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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

June 13, 2008

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2007-0681 – Hydro One Networks' 2008 Distribution Rate Application – Evidence Update Filing

Hydro One Networks Inc. is updating the evidence filed to date with the Board.

An electronic copy of the complete application, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

The scope of this update is narrowly defined and does not result in a change to the requested 2008 revenue requirement of $1,067 million. The material provided with this update will contribute to the accuracy and completeness of the evidence in this application, and covers the following items:

1. 2007 year-end Hydro One Networks Distribution and 2008 first quarter Hydro One Incorporated financial statements.
2. 2007 Hydro One Incorporated Annual Report.
3. Corrections identified in the pre-filed evidence and interrogatory responses.

To facilitate the integration of this update into your copies of pre-filed evidence, we are attaching a Distribution Application Update Instruction.

Hydro One Networks will post electronic copies of the update on the Hydro One Networks' website for public access. In addition, one copy is being provided for public access at each of the following Hydro One Networks' offices –

Hydro One Networks Head Office, 8th Floor, South Tower, 483 Bay Street, Toronto, Ontario

Hydro One Networks Barrie Field Business Centre, 45 Sarjeant Drive, Barrie, Ontario

Hydro One Networks Peterborough Field Business Centre, 913 Crawford Drive, Peterborough, Ontario

Hydro One Networks Sudbury Field Business Centre, 957 Falconbridge Road, Sudbury, Ontario

Hydro One Networks Merivale Service Centre, 31 Woodfield Drive, Ottawa, Ontario

Hydro One Networks Dundas Field Business Centre, 40 Olympic Drive, Dundas, Ontario

Hydro One Networks Beachville Field Business Centre, 56 Embro Street, Beachville, Ontario

Hydro One Networks Thunder Bay Field Business Centre, 255 Burwood Road, Thunder Bay, Ontario

Hydro One Networks' point of contact for service of documents associated with this Application is listed in Exhibit A, Tab 1, Schedule 1.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

cc: Intervenors of EB-2007-0681

EB-2007-0681 Distribution Application Update Instruction[1]

Exhibit A, Tab 9, Schedule 1	Update page 1
Exhibit A, Tab 9, Schedule 1	Insert new Attachment 4
Exhibit A, Tab 10, Schedule 1	Update page 1
Exhibit A, Tab 10, Schedule 1	Insert new Attachment 2
Exhibit A, Tab 10, Schedule 2	Update page 1
Exhibit A, Tab 10, Schedule 2	Insert new Attachment 5
Exhibit A, Tab 20, Schedule 1	Update pages 1, 2
Exhibit C1, Tab 2, Schedule 2	Update page 3, 4
Exhibit H, Tab 1, Schedule 59	Update page 1
Exhibit H, Tab 1, Schedule 71	Update page 1
Exhibit H, Tab 12, Schedule 51	Update page 1, 2
Exhibit H, Tab 13, Schedule 66	Update page 1, 2

[1]Note: not all pages have revisions but have been included for convenience.

Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
OEB Staff	1	1	Tab	1	Schedule	1
OEB Staff	1	2	Tab	1	Schedule	2
OEB Staff	1	3	Tab	1	Schedule	3
OEB Staff	1	4	Tab	1	Schedule	4
OEB Staff	1	5	Tab	1	Schedule	5
OEB Staff	1	6	Tab	1	Schedule	6
OEB Staff	1	7	Tab	1	Schedule	7
OEB Staff	1	8	Tab	1	Schedule	8
OEB Staff	1	9	Tab	1	Schedule	9
OEB Staff	1	10	Tab	1	Schedule	10
OEB Staff	1	11	Tab	1	Schedule	11
OEB Staff	1	12	Tab	1	Schedule	12
OEB Staff	1	13	Tab	1	Schedule	13
OEB Staff	1	14	Tab	1	Schedule	14
OEB Staff	1	15	Tab	1	Schedule	15
OEB Staff	1	16	Tab	1	Schedule	16
OEB Staff	1	17	Tab	1	Schedule	17
OEB Staff	1	18	Tab	1	Schedule	18
OEB Staff	1	19	Tab	1	Schedule	19
OEB Staff	1	20	Tab	1	Schedule	20
OEB Staff	1	21	Tab	1	Schedule	21
OEB Staff	1	22	Tab	1	Schedule	22
OEB Staff	1	23	Tab	1	Schedule	23
OEB Staff	1	24	Tab	1	Schedule	24
OEB Staff	1	25	Tab	1	Schedule	25
OEB Staff	1	26	Tab	1	Schedule	26
OEB Staff	1	27	Tab	1	Schedule	27
OEB Staff	1	28	Tab	1	Schedule	28
OEB Staff	1	29	Tab	1	Schedule	29
OEB Staff	1	30	Tab	1	Schedule	30
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OEB Staff	1	63	Tab	1	Schedule	63
OEB Staff	1	64	Tab	1	Schedule	64
OEB Staff	1	65	Tab	1	Schedule	65
OEB Staff	1	66	Tab	1	Schedule	66
OEB Staff	1	67	Tab	1	Schedule	67
OEB Staff	1	68	Tab	1	Schedule	68
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Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
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OEB Staff	1	72	Tab	1	Schedule	72
OEB Staff	1	73	Tab	1	Schedule	73
OEB Staff	1	74	Tab	1	Schedule	74
OEB Staff	1	75	Tab	1	Schedule	75
OEB Staff	1	76	Tab	1	Schedule	76
OEB Staff	1	77	Tab	1	Schedule	77
OEB Staff	1	78	Tab	1	Schedule	78
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OEB Staff	1	82	Tab	1	Schedule	82
OEB Staff	1	83	Tab	1	Schedule	83
OEB Staff	1	84	Tab	1	Schedule	84
OEB Staff	1	85	Tab	1	Schedule	85
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OEB Staff	1	88	Tab	1	Schedule	88
OEB Staff	1	89	Tab	1	Schedule	89
OEB Staff	1	90	Tab	1	Schedule	90
OEB Staff	1	91	Tab	1	Schedule	91
OEB Staff	1	92	Tab	1	Schedule	92
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OEB Staff	1	94	Tab	1	Schedule	94
OEB Staff	1	95	Tab	1	Schedule	95
OEB Staff	1	96	Tab	1	Schedule	96
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OEB Staff	1	102	Tab	1	Schedule	102
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OEB Staff	1	104	Tab	1	Schedule	104
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OEB Staff	1	109	Tab	1	Schedule	109
OEB Staff	1	110	Tab	1	Schedule	110
OEB Staff	1	111	Tab	1	Schedule	111
OEB Staff	1	112	Tab	1	Schedule	112
OEB Staff	1	113	Tab	1	Schedule	113
OEB Staff	1	114	Tab	1	Schedule	114
OEB Staff	1	115	Tab	1	Schedule	115
OEB Staff	1	116	Tab	1	Schedule	116
OEB Staff	1	117	Tab	1	Schedule	117
OEB Staff	1	118	Tab	1	Schedule	118
OEB Staff	1	119	Tab	1	Schedule	119
OEB Staff	1	120	Tab	1	Schedule	120
OEB Staff	1	121	Tab	1	Schedule	121
OEB Staff	1	122	Tab	1	Schedule	122
OEB Staff	1	123	Tab	1	Schedule	123
OEB Staff	1	124	Tab	1	Schedule	124
OEB Staff	1	125	Tab	1	Schedule	125
OEB Staff	1	126	Tab	1	Schedule	126
OEB Staff	1	127	Tab	1	Schedule	127
OEB Staff	1	128	Tab	1	Schedule	128
OEB Staff	1	129	Tab	1	Schedule	129
OEB Staff	1	130	Tab	1	Schedule	130
OEB Staff	1	131	Tab	1	Schedule	131
OEB Staff	1	132	Tab	1	Schedule	132
OEB Staff	1	133	Tab	1	Schedule	133
OEB Staff	1	134	Tab	1	Schedule	134
OEB Staff	1	135	Tab	1	Schedule	135
OEB Staff	1	136	Tab	1	Schedule	136
OEB Staff	1	137	Tab	1	Schedule	137
OEB Staff	1	138	Tab	1	Schedule	138

Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
OEB Staff	1	139	Tab	1	Schedule	139
OEB Staff	1	140	Tab	1	Schedule	140
OEB Staff	1	141	Tab	1	Schedule	141
OEB Staff	1	142	Tab	1	Schedule	142
OEB Staff	1	143	Tab	1	Schedule	143
OEB Staff	1	144	Tab	1	Schedule	144
OEB Staff	1	145	Tab	1	Schedule	145
OEB Staff	1	146	Tab	1	Schedule	146
OEB Staff	1	147	Tab	1	Schedule	147
OEB Staff	1	148	Tab	1	Schedule	148
OEB Staff	1	149	Tab	1	Schedule	149
OEB Staff	1	150	Tab	1	Schedule	150
OEB Staff	1	151	Tab	1	Schedule	151
OEB Staff	1	152	Tab	1	Schedule	152
OEB Staff	1	153	Tab	1	Schedule	153
OEB Staff	1	154	Tab	1	Schedule	154
OEB Staff	1	155	Tab	1	Schedule	155
OEB Staff	1	156	Tab	1	Schedule	156
OEB Staff	1	157	Tab	1	Schedule	157
OEB Staff	1	158	Tab	1	Schedule	158
OEB Staff	1	159	Tab	1	Schedule	159
OEB Staff	1	160	Tab	1	Schedule	160
OEB Staff	1	161	Tab	1	Schedule	161
OEB Staff	1	162	Tab	1	Schedule	162
OEB Staff	1	163	Tab	1	Schedule	163

Interrogatory Index						
Intervenor Name	**Question List**	**Question Number**	**Equivalent Tab and Schedule Number - All responses are Exhibit H**			
Pollution Probe	1	1	Tab	2	Schedule	1
Pollution Probe	1	2	Tab	2	Schedule	2
Pollution Probe	1	3	Tab	2	Schedule	3
Pollution Probe	1	4	Tab	2	Schedule	4
Pollution Probe	1	5	Tab	2	Schedule	5
Pollution Probe	1	6	Tab	2	Schedule	6
Pollution Probe	1	7	Tab	2	Schedule	7
Pollution Probe	1	8	Tab	2	Schedule	8
Pollution Probe	1	9	Tab	2	Schedule	9
Pollution Probe	1	10	Tab	2	Schedule	10
Pollution Probe	1	11	Tab	2	Schedule	11
Pollution Probe	1	12	Tab	2	Schedule	12
Pollution Probe	1	13	Tab	2	Schedule	13
Pollution Probe	1	14	Tab	2	Schedule	14
Pollution Probe	1	15	Tab	2	Schedule	15
Pollution Probe	1	16	Tab	2	Schedule	16
Pollution Probe	1	17	Tab	2	Schedule	17
Pollution Probe	1	18	Tab	2	Schedule	18
Pollution Probe	1	19	Tab	2	Schedule	19
Pollution Probe	1	20	Tab	2	Schedule	20
Pollution Probe	1	21	Tab	2	Schedule	21
Pollution Probe	1	22	Tab	2	Schedule	22
Pollution Probe	1	23	Tab	2	Schedule	23
Pollution Probe	1	24	Tab	2	Schedule	24
Pollution Probe	1	25	Tab	2	Schedule	25
GEC	1	1	Tab	3	Schedule	1
GEC	1	2	Tab	3	Schedule	2
GEC	1	3	Tab	3	Schedule	3
GEC	1	4	Tab	3	Schedule	4
ECMI	1	1	Tab	4	Schedule	1
ECMI	1	2	Tab	4	Schedule	2
ECMI	1	3	Tab	4	Schedule	3
ECMI	1	4	Tab	4	Schedule	4
ECMI	1	5	Tab	4	Schedule	5
ECMI	1	6	Tab	4	Schedule	6
ECMI	1	7	Tab	4	Schedule	7
ECMI	1	8	Tab	4	Schedule	8
ECMI	1	9	Tab	4	Schedule	9
ECMI	1	10	Tab	4	Schedule	10
Wescast	1	1	Tab	5	Schedule	1
Wescast	1	2	Tab	5	Schedule	2
PWU	1	1	Tab	6	Schedule	1
PWU	1	2	Tab	6	Schedule	2
PWU	1	3	Tab	6	Schedule	3
PWU	1	4	Tab	6	Schedule	4

Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
Energy Probe	1	1	Tab	7	Schedule	1
Energy Probe	1	2	Tab	7	Schedule	2
Energy Probe	1	3	Tab	7	Schedule	3
Energy Probe	1	4	Tab	7	Schedule	4
Energy Probe	1	5	Tab	7	Schedule	5
Energy Probe	1	6	Tab	7	Schedule	6
Energy Probe	1	7	Tab	7	Schedule	7
Energy Probe	1	8	Tab	7	Schedule	8
Energy Probe	1	9	Tab	7	Schedule	9
Energy Probe	1	10	Tab	7	Schedule	10
Energy Probe	1	11	Tab	7	Schedule	11
Energy Probe	1	12	Tab	7	Schedule	12
Energy Probe	1	13	Tab	7	Schedule	13
Energy Probe	1	14	Tab	7	Schedule	14
Energy Probe	1	15	Tab	7	Schedule	15
Energy Probe	1	16	Tab	7	Schedule	16
Energy Probe	1	17	Tab	7	Schedule	17
Energy Probe	1	18	Tab	7	Schedule	18
Energy Probe	1	19	Tab	7	Schedule	19
Energy Probe	1	20	Tab	7	Schedule	20
Energy Probe	1	21	Tab	7	Schedule	21
Energy Probe	1	22	Tab	7	Schedule	22
Energy Probe	1	23	Tab	7	Schedule	23
Energy Probe	1	24	Tab	7	Schedule	24
Energy Probe	1	25	Tab	7	Schedule	25
Energy Probe	1	26	Tab	7	Schedule	26
Energy Probe	1	27	Tab	7	Schedule	27
Energy Probe	1	28	Tab	7	Schedule	28
Energy Probe	1	29	Tab	7	Schedule	29
Energy Probe	1	30	Tab	7	Schedule	30
Energy Probe	1	31	Tab	7	Schedule	31
Energy Probe	1	32	Tab	7	Schedule	32
Rogers	1	1	Tab	8	Schedule	1
Rogers	1	2	Tab	8	Schedule	2
Rogers	1	3	Tab	8	Schedule	3
Rogers	1	4	Tab	8	Schedule	4
Rogers	1	5	Tab	8	Schedule	5
Rogers	1	6	Tab	8	Schedule	6
Rogers	1	7	Tab	8	Schedule	7
Rogers	1	8	Tab	8	Schedule	8
Rogers	1	9	Tab	8	Schedule	9
Rogers	1	10	Tab	8	Schedule	10
Rogers	1	11	Tab	8	Schedule	11
Rogers	1	12	Tab	8	Schedule	12
Milton Hydro	1	1	Tab	9	Schedule	1
Milton Hydro	1	2	Tab	9	Schedule	2
Milton Hydro	1	3	Tab	9	Schedule	3
Milton Hydro	1	4	Tab	9	Schedule	4
Milton Hydro	1	5	Tab	9	Schedule	5
Milton Hydro	1	6	Tab	9	Schedule	6
Milton Hydro	1	7	Tab	9	Schedule	7
Milton Hydro	1	8	Tab	9	Schedule	8
Milton Hydro	1	9	Tab	9	Schedule	9
Milton Hydro	1	10	Tab	9	Schedule	10
Milton Hydro	1	11	Tab	9	Schedule	11
Milton Hydro	1	12	Tab	9	Schedule	12
Milton Hydro	1	13	Tab	9	Schedule	13
Milton Hydro	1	14	Tab	9	Schedule	14
Milton Hydro	1	15	Tab	9	Schedule	15

Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
CCC	1	1	Tab	10	Schedule	1
CCC	1	2	Tab	10	Schedule	2
CCC	1	3	Tab	10	Schedule	3
CCC	1	4	Tab	10	Schedule	4
CCC	1	5	Tab	10	Schedule	5
CCC	1	6	Tab	10	Schedule	6
CCC	1	7	Tab	10	Schedule	7
CCC	1	8	Tab	10	Schedule	8
CCC	1	9	Tab	10	Schedule	9
CCC	1	10	Tab	10	Schedule	10
CCC	1	11	Tab	10	Schedule	11
CCC	1	12	Tab	10	Schedule	12
CCC	1	13	Tab	10	Schedule	13
CCC	1	14	Tab	10	Schedule	14
CCC	1	15	Tab	10	Schedule	15
CCC	1	16	Tab	10	Schedule	16
CCC	1	17	Tab	10	Schedule	17
CCC	1	18	Tab	10	Schedule	18
CCC	1	19	Tab	10	Schedule	19
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CCC	1	21	Tab	10	Schedule	21
CCC	1	22	Tab	10	Schedule	22
CCC	1	23	Tab	10	Schedule	23
CCC	1	24	Tab	10	Schedule	24
CCC	1	25	Tab	10	Schedule	25
CCC	1	26	Tab	10	Schedule	26
CCC	1	27	Tab	10	Schedule	27
CCC	1	28	Tab	10	Schedule	28
CCC	1	29	Tab	10	Schedule	29
CCC	1	30	Tab	10	Schedule	30
CCC	1	31	Tab	10	Schedule	31
CCC	1	32	Tab	10	Schedule	32
CCC	1	33	Tab	10	Schedule	33
CCC	1	34	Tab	10	Schedule	34
CCC	1	35	Tab	10	Schedule	35
CCC	1	36	Tab	10	Schedule	36
CCC	1	37	Tab	10	Schedule	37
CCC	1	38	Tab	10	Schedule	38
CCC	1	39	Tab	10	Schedule	39
CCC	1	40	Tab	10	Schedule	40
CCC	1	41	Tab	10	Schedule	41
CCC	1	42	Tab	10	Schedule	42
CCC	1	43	Tab	10	Schedule	43
CCC	1	44	Tab	10	Schedule	44
CCC	1	45	Tab	10	Schedule	45

Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
AMPCO	1	1	Tab	11	Schedule	1
AMPCO	1	2	Tab	11	Schedule	2
AMPCO	1	3	Tab	11	Schedule	3
AMPCO	1	4	Tab	11	Schedule	4
AMPCO	1	5	Tab	11	Schedule	5
AMPCO	1	6	Tab	11	Schedule	6
AMPCO	1	7	Tab	11	Schedule	7
AMPCO	1	8	Tab	11	Schedule	8
AMPCO	1	9	Tab	11	Schedule	9
AMPCO	1	10	Tab	11	Schedule	10
AMPCO	1	11	Tab	11	Schedule	11
AMPCO	1	12	Tab	11	Schedule	12
AMPCO	1	13	Tab	11	Schedule	13
AMPCO	1	14	Tab	11	Schedule	14
AMPCO	1	15	Tab	11	Schedule	15
AMPCO	1	16	Tab	11	Schedule	16
AMPCO	1	17	Tab	11	Schedule	17
AMPCO	1	18	Tab	11	Schedule	18
AMPCO	1	19	Tab	11	Schedule	19
AMPCO	1	20	Tab	11	Schedule	20
AMPCO	1	21	Tab	11	Schedule	21
AMPCO	1	22	Tab	11	Schedule	22
AMPCO	1	23	Tab	11	Schedule	23
AMPCO	1	24	Tab	11	Schedule	24
AMPCO	1	25	Tab	11	Schedule	25
AMPCO	1	26	Tab	11	Schedule	26
AMPCO	1	27	Tab	11	Schedule	27
AMPCO	1	28	Tab	11	Schedule	28
AMPCO	1	29	Tab	11	Schedule	29
AMPCO	1	30	Tab	11	Schedule	30
AMPCO	1	31	Tab	11	Schedule	31
AMPCO	1	32	Tab	11	Schedule	32
AMPCO	1	33	Tab	11	Schedule	33
AMPCO	1	34	Tab	11	Schedule	34
AMPCO	1	35	Tab	11	Schedule	35
AMPCO	1	36	Tab	11	Schedule	36
AMPCO	1	37	Tab	11	Schedule	37
AMPCO	1	38	Tab	11	Schedule	38
AMPCO	1	39	Tab	11	Schedule	39
AMPCO	1	40	Tab	11	Schedule	40
AMPCO	1	41	Tab	11	Schedule	41
VECC	1	1	Tab	12	Schedule	1
VECC	1	2	Tab	12	Schedule	2
VECC	1	3	Tab	12	Schedule	3
VECC	1	4	Tab	12	Schedule	4
VECC	1	5	Tab	12	Schedule	5
VECC	1	6	Tab	12	Schedule	6
VECC	1	7	Tab	12	Schedule	7
VECC	1	8	Tab	12	Schedule	8
VECC	1	9	Tab	12	Schedule	9
VECC	1	10	Tab	12	Schedule	10
VECC	1	11	Tab	12	Schedule	11
VECC	1	12	Tab	12	Schedule	12
VECC	1	13	Tab	12	Schedule	13
VECC	1	14	Tab	12	Schedule	14
VECC	1	15	Tab	12	Schedule	15
VECC	1	16	Tab	12	Schedule	16
VECC	1	17	Tab	12	Schedule	17
VECC	1	18	Tab	12	Schedule	18
VECC	1	19	Tab	12	Schedule	19
VECC	1	20	Tab	12	Schedule	20
VECC	1	21	Tab	12	Schedule	21
VECC	1	22	Tab	12	Schedule	22
VECC	1	23	Tab	12	Schedule	23
VECC	1	24	Tab	12	Schedule	24
VECC	1	25	Tab	12	Schedule	25
VECC	1	26	Tab	12	Schedule	26
VECC	1	27	Tab	12	Schedule	27
VECC	1	28	Tab	12	Schedule	28

Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
VECC	1	29	Tab	12	Schedule	29
VECC	1	30	Tab	12	Schedule	30
VECC	1	31	Tab	12	Schedule	31
VECC	1	32	Tab	12	Schedule	32
VECC	1	33	Tab	12	Schedule	33
VECC	1	34	Tab	12	Schedule	34
VECC	1	35	Tab	12	Schedule	35
VECC	1	36	Tab	12	Schedule	36
VECC	1	37	Tab	12	Schedule	37
VECC	1	38	Tab	12	Schedule	38
VECC	1	38	Tab	12	Schedule	39
VECC	1	39	Tab	12	Schedule	40
VECC	1	40	Tab	12	Schedule	41
VECC	1	41	Tab	12	Schedule	42
VECC	1	42	Tab	12	Schedule	43
VECC	1	43	Tab	12	Schedule	44
VECC	1	44	Tab	12	Schedule	45
VECC	1	45	Tab	12	Schedule	46
VECC	1	46	Tab	12	Schedule	47
VECC	1	47	Tab	12	Schedule	48
VECC	1	48	Tab	12	Schedule	49
VECC	1	49	Tab	12	Schedule	50
VECC	1	50	Tab	12	Schedule	51
VECC	1	51	Tab	12	Schedule	52
VECC	1	52	Tab	12	Schedule	53
VECC	1	53	Tab	12	Schedule	54
VECC	1	54	Tab	12	Schedule	55
VECC	1	55	Tab	12	Schedule	56
VECC	1	56	Tab	12	Schedule	57
VECC	1	57	Tab	12	Schedule	58
VECC	1	58	Tab	12	Schedule	59
VECC	1	59	Tab	12	Schedule	60
VECC	1	60	Tab	12	Schedule	61
VECC	1	61	Tab	12	Schedule	62
VECC	1	62	Tab	12	Schedule	63
VECC	1	63	Tab	12	Schedule	64
VECC	1	64	Tab	12	Schedule	65
VECC	1	65	Tab	12	Schedule	66
VECC	1	66	Tab	12	Schedule	67
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VECC	1	68	Tab	12	Schedule	69
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VECC	1	71	Tab	12	Schedule	72
VECC	1	72	Tab	12	Schedule	73
VECC	1	73	Tab	12	Schedule	74
VECC	1	74	Tab	12	Schedule	75
VECC	1	75	Tab	12	Schedule	76
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Interrogatory Index						
Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
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Ontario Energy Board (Board Staff) INTERROGATORY #1 List 1

Interrogatory

Ref: Exhibit C1 Tab 6 Schedule 1 – Impacts of Distribution Asset Acquisitions and Sales, page 2 of 4, Table 1 / Issue 4.1

Hydro One states that it does not forecast losses/gains on the sale of assets. However, Hydro One has filed several applications under section 86 of the OEB Act for the acquisition or sale of assets.
Please indicate if and how the value of these transactions (or proposed transactions), is reflected in the 2008 test year rate base.

Response

The section 86 transactions that are before the Board are not reflected in the 2008 test year rate base. There is typically little gain or loss on the sale of assets under the majority of section 86 applications. The aggregate amount of purchases or sale as compared to our rate base is small. Any material sale would be reviewed by the Board as part of a section 86 application.

Ontario Energy Board (Board Staff) INTERROGATORY #2 List 1

Interrogatory

Ref: Exhibit D1 Tab 1 Schedule 1 – Continuity of Fixed Assets Summary and Rate Base/ Issue 4.1

Please update Table 2 – Continuity of Fixed Assets Summary and Table 1 – 2008 Distribution Rate base to reflect the 2007 actuals.

Response

Updated tables below:

Table 1
Distribution Rate Base ($ Millions)

Description	Test 2008
Gross Plant	6,371.2
Accumulated Depreciation	(2,378.5)
Net Plant	3,992.8
Cash Working Capital	273.2
Materials and Supplies Inventory	23.3
Distribution Rate Base	**4,289.3**

Table 2
Continuity of Fixed Assets Summary ($ Million)

Description	Historic			Bridge	Test
	2004	2005	2006	2007	2008
Opening Gross Asset Balance	4,941.9	5,224.8	5,492.7	5,866.5	6,098.3
In-Service Additions	285.1	290.7	379.9	416.5	595.9
Retirements	(31.8)	(23.2)	(10.9)	(184.8)	(50.8)
Sales	(16.3)	(3.6)	(10.3)	(8.5)	-
Transfers	45.9	4.0	15.1	8.6	0.6
Closing Gross Asset Balance	5,224.8	5,492.7	5,866.5	6,098.3	6,644.0
Mid Year Gross Asset Balance	5,083.4	5,358.8	5,679.6	5,982.4	6,371.2

Ontario Energy Board (Board Staff) INTERROGATORY #3 List 1

Interrogatory

3. Ref: Exhibit D1 Tab 1 Schedule 1 – Capital Expenditures/ Issue 4.1

For each of the years 2002 through 2008, please provide:

a) A table listing the following, using actual values in years where available, and if not, then using expected or planned or projected, or percent(%):
   I) Allowed Return on Equity (%) portion of the regulated rate base;
   II) Actual Return on Equity (%) portion of the regulated rate base;
   III) Retained Earnings;
   IV) Dividends to shareholders;
   V) Sustainment Capital expenditures excluding smart meters;
   VI) Development Capital Expenditures excluding smart meters;
   VII) Operations Capital Expenditures;
   VIII) Smart meters Capital Expenditures;
   IX) Other Capital Expenditures (identify);
   X) Total Capital Expenditures including and excluding smart meters;
   XI) Depreciation;
   XII) Construction Work in Progress;
   XIII) Number of customer additions by class;
   XIV) Rate Base.

b) For the years 2002 to 2008 inclusive, please complete the following table including actuals, estimated dollars and percent (%) where indicated. Please identify the cost drivers, as indicated in the table. (Examples of cost drivers are: building new facilities, replacement of obsolete poles, and replacement of aging underground cables). Please identify the type and amount of any one-time, unusual expenditure incurred in any particular year that caused the change outside the given threshold, as provided in the table. Please **exclude** smart meter expenditures from the capital expenditures.

	Capital Expenditure (A) ($)		**Capital Expenditure (B) ($)**	**Change (AB) ($)**	**% Change (A/B)**	**Cost Drivers for the change (increase or decrease) if the % change is either less than zero or more than 10%**
2003		2002				
2004		2003				
2005		2004				
2006 Actual		2005				
2006 Actual		2006 Board Approved				
2007 Bridge Year		2006 Actual				
2008 Test Year		2007 Bridge Year				

Response

a)

in $M except where noted	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Bridge	2008 Test [1]
Allowed Return on Equity (%) portion of the regulated rate base [2]	9.44%	9.44%	9.44%	9.44%	8.64%	8.64%	8.64%
Actual Return on Equity (%) portion of the regulated rate base [3]	4.5%	3.6%	12.1%	6.7%	8.5%	5.9%	7.9%
Retained Earnings [4]	120	161	322	372	451	512	614
Dividends to shareholders	5	5	5	46	47	34	36
Sustainment Capital expenditures excluding smart meters	99.4	116.3	104.9	117.3	172.2	146.9	152.3
Development Capital Expenditures excluding smart meters	100	107.1	138.6	141.7	146.8	154.2	167.7
Operations Capital Expenditures	3.7	11.1	6.3	4.7	2.1	2.0	3.6
Smart meters Capital Expenditures					14.1	76.7	164.8
Other Capital Expenditures (identify)							
Network Line Losses					1.1	5.6	0.0
Transport and Work, and Service Equipment	22.2	36.7	12.0	32.1	33.6	35.7	44.5
Information Technology Capital	24.1	7.3	10.6	19.5	19.3	20.1	15.3
Cornerstone Project						26.6	28.0
Facilities Capital	0.7	1.2	2.8	1.8	2.1	6.4	4.4
Conservation & Demand Management					1.8	2.3	0.0
Other	12.1	0.6	(3.2)	0.1	(0.5)	0.1	(14.4)
Total Other capital expenditures	59.1	45.8	22.2	53.4	57.4	96.7	77.8
Total Distribution Capital including smart meters	262.2	280.4	272.0	317.2	392.6	476.6	566.2
Total Distribution Capital excluding smart meters	262.2	280.4	272.0	317.2	378.5	399.9	401.4
Depreciation (of fixed assets in service)	120	129	152	155	159	164	197
Construction Work in Progress	68	64	53	80	87	94	65
Number of customer additions by class [5]							
Retail							
UR		2,150	2,684	1,844	1,529	1,569	1,481
R1		5,854	6,255	4,366	4,873	4,074	3,843
R2		4,160	4,796	3,441	2,880	2,941	2,780
R3		(485)	(285)	293	(10)	(78)	(74)
R4		157	8	587	354	268	253
F1		(841)	(1,305)	(370)	(578)	(585)	(553)
F3		(42)	3	7	(0)	2	2

in $M except where noted	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Bridge	2008 Test [1]
UG		25	9	(30)	73	16	15
G1		(497)	45	221	89	97	92
G3		(562)	200	385	302	243	230
T		44	5	3	5	3	3
Lights		-	-	-	-	-	-
Subtotal		9,964	12,416	10,747	9,517	8,550	8,074
Acquired							
Acq Residential		1,698	1,833	1,561	817	2,230	1,238
Acq General Service		(851)	54	93	199	196	94
Acq Large Users		-	-	(1)	1	-	-
Subtotal		847	1,887	1,653	1,017	2,426	1,332
Direct & LDC Accounts		3	3	3	41	(13)	7
Total customer additions		10,814	14,306	12,403	10,575	10,963	9,413
Rate Base [6]	3095	3239	3419	3579	3720	4014	4382

Footnotes

[1] Based on proforma financial statements

[2] Weighted allowed return on total equity (common and preferred)

[3] Calculated as net income divided by deemed total equity

[4] Retained Earnings is derived from Excess of Assets over Liabilities in Hydro One Distribution audited financial statements

[5] 2002 Number of customer additions by class not available

[6] 2002-2005 allowance for working capital calculated as 15% of OM&A and Purchased Power. 2006-2008 allowance for working capital calculated using Lead Lag Study and includes materials and supplies inventory

1

b)

	Capital Expenditure (A) ($)		Capital Expenditure (B) ($)	Change (A-B) ($)	% Change (A/B)	Cost Drivers for the change (increase or decrease) if the % change is either less than zero or more than 10%
2003	280.4	2002	262.2	18.2	7%	
2004	272.0	2003	280.4	(8.4)	-3%	Expenditures were lower in 2004 primarily due to lower storm damage costs and reduced Transport & Work Equipment expenditures due to advancement of purchases into 2003, partially offset by higher labour costs caused by the increase in payroll burden recognizing Hydro One's higher pension obligation in 2004, the change in DSC policy that reduced the funds that Hydro One could collect from customers, and higher trouble program costs
2005	317.2	2004	272.0	45.3	17%	Distribution Capital expenditures in 2005 were higher than those of 2004. Capital expenditures to sustain our distribution system increased primarily due to increased investments related to storm damage recovery and transport and work equipment, including brushing equipment to assist with our forestry program and increased new connections work. Also, there were increased investments in information technology assets including projects to facilitate integrated work planning, and replace an outdated computer telephony interface, call centre applications, and aging servers and IT resources. Due to a labour disruption these increases were partially offset by a reduction in expenditures to expand and reinforce the low voltage distribution system.
2006 Actual	378.5	2005	317.2	61.3	19%	The increase in 2006 compared to 2005 was primarily due to higher planned replacements of end of life assets (e.g. wood pole replacements), combined with increased expenditures for other unplanned asset replacements and line relocations, as well as the impact of the previous year's labour disruption. There also were higher asset replacement expenditures related to storm damage.
2006 Actual	378.5	2006 Board Approved	333.0	45.5	14%	Distribution capital expenditures were higher than the Board approved figure primarily due to higher than planned Distribution storm repair, new connection and line relocation work. These increases were partially offset by a reduction in our investments in information technology assets.
2007 Bridge Year	399.9	2006 Actual	378.5	21.4	6%	N/A (less than 10%)
2008 Test Year	401.4	2007 Bridge Year	399.9	1.5	0%	N/A (less than 10%)

Ontario Energy Board (Board Staff) INTERROGATORY #4 List 1

Interrogatory

Ref: Exhibit D1 Tab 1 Schedule 1 – Cash Flow/ Issue 4.1

Please provide cash flow data for 2002 to 2008 in the following format.

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual or Projected	2008 Projected
1.Net Income (loss)							
2. Total Depreciation & Amortization Expenses							
3. Total Capital Expenditures (including Smart Meters)							
4.Non-cash working capital balances							
5. Other							
Subtotal (A=1+2+3+4+5)							
Cash, beginning of period (B)							
Cash, end of period (B) + (A)							

Response

Cash flow data for 2002-08 is provided below:

$ millions	**Actual 2002**	**Actual 2003**	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Proj. 2007**	**Proj. 2008**
Net income	56	46	164	96	126	94	138
Depreciation	150	182	194	195	219	229	243
Capital expenditures	(262)	(280)	(272)	(317)	(393)	(516)	(566)
Non-cash working capital	(164)	63	(52)	114	(140)	79	40
Other	191	246	(10)	72	62	80	187
Sub-total	**(29)**	**257**	**24**	**160**	**(126)**	**(34)**	**42**
Cash*, beg. of period	(352)	(381)	(124)	(102)	58	(68)	(102)
Cash*, end of period	(381)	(124)	(100)	58	(68)	(102)	(60)

* Inter-company demand facility.

Ontario Energy Board (Board Staff) INTERROGATORY #5 List 1

Interrogatory

Reference: Exhibit D1 Tab 1 Schedule 1 – Depreciation/ Issue 4.3

a. Please confirm the statement on page 3 that "plant older than the proposed amortization period be immediately retired from service" does not mean physical retirement, but rather a set of accounting entries that effectively removes that item's net asset value, if any, from Rate base. If that is not correct, please clarify the statement.

b. Please define the retirement categories mentioned in lines 18-20, namely:
   I) "resulting from assets reaching their end of life";
   II) "due to the Distribution portion of Passport"; and
   III) "normal retirements".

Response

a. Hydro One Distribution confirms that the term "retirement" is used in this context to refer to an accounting transaction rather than physical removal from service.

b. The retirement categories mentioned in lines 18-20 are more fully explained below:

   I) "resulting from assets reaching their end of life" - refers to amortizable capital assets (i.e. certain minor fixed assets or conventional meters) that are retired for accounting purposes upon completion of their assigned accounting service life, irrespective of operational status;

   II) "due to the Distribution portion of Passport" refers to the expected retirement of the Passport system upon placement in service of its successor system, Cornerstone; and

   III) "normal retirements" are accounting retirements that are triggered by removing assets and major asset components from operational service.

Ontario Energy Board (Board Staff) INTERROGATORY #6 List 1

Interrogatory

Ref: Exhibit D1 Tab 1 Schedule 1 – Transfers/ Issue 4.1

In Table 2 – Continuity of Fixed Assets Summary, Hydro One shows net transfers of $7.2M in 2007 and $0.6M in 2008. Hydro One Networks states that the net transfers of $15.1M in 2006 primarily reflect "the transfer of wholesale meters to Distribution due to deregistration of the meters" (page 4 of 5).
[Emphasis Added]. Please provide further explanation of other transfers for the 2007 bridge and 2008 test years.

Response

Forecasted asset transfers in 2007 and 2008 include the following:

- transfer of wholesale meters from Transmission ($0.6M in 2007 and $0.6M in 2008);
- transfer of assets from Transmission to reflect the implementation of the latest common asset splits as of January 1, 2007 ($3.5M in 2007 and zero in 2008); and
- transfer of smart meter in-service asset balance previously treated as a regulatory asset ($3.1M in 2007 and zero in 2008).

Ontario Energy Board (Board Staff) INTERROGATORY #7 List1

Interrogatory

Reference: 2006 Filing requirement (EB-2006-0170) section 2.3 Exhibit 2 – Leave to Construct Applications/ Issue 4.2

a. Please provide the corporate capitalization policy and indicate any changes since 2006 from prior policy and the rationale for any change. Please also provide for each of the historical, bridge and test years:
b. A listing of depreciation for each of the USoA Groupings (i.e. by Asset Account) as listed in Exhibit D2 Tab2 Schedule 4, page 1.
c. The Continuity statements for Accumulated Depreciation of Assets by function (i.e. transmission plant, distribution plant, general plant, other plant).
d. Please confirm that Hydro One Distribution has no Leave to Construct projects under section 92, or if Hydro One Distribution has Leave to Construct applications under section 92 before the Board, please provide a list of all such applications. For each application, provide the cost estimate of the Leave to Construct project and indicate if the project has been included in the 2008 test year rate base.

Response

a. The Corporation's capitalization accounting policy dated October 2000, "Classification of Expenditures," is attached as Attachment A. This policy has not been revised since then.

b. Depreciation on fixed assets by USofA grouping for historical, bridge and test years is shown in the following table:

($ millions)	**2006**	**2007**	**2008**
Land and buildings	3.5	3.5	3.4
TS primary above 50	1.9	2.0	2.1
Distribution station equipment	5.8	5.8	6.4
Poles, wires	61.0	68.1	79.3
Line transformers	36.9	27.0	24.6
Services and meters	5.7	5.0	5.3
General plant	2.5	2.3	2.3
Equipment	23.2	27.9	32.6
IT assets	16.2	22.1	28.9

Other distribution assets	2.1	2.1	2.4
Smart meters	0.2	3.0	9.6
Sub-total (D2-3-2)	**159.2**	**168.9**	**196.9**
Adjustment	-	(4.9)	-
Total (C2-5-1)	**159.2**	**164.0**	**196.9**

c. Continuity statements for accumulated depreciation by function for historical, bridge and test years are provided in the following tables:

	2006			
	Dx Plant	General Plant	Other	Total
Opening balance	1,819.4	355.9	0.5	2,175.8
Depreciation	114.9	44.1	0.2	159.2
Retirements	(10.3)	(9.8)	0.0	(20.1)
Transfers	15.5	(1.5)	(0.2)	13.8
Closing balance	1,939.5	388.7	0.5	2,328.7

	2007			
	Dx Plant	General Plant	Other	Total
Opening balance	1,939.5	388.7	0.5	2,328.7
Depreciation	114.4	54.5	-	168.9
Retirements	(145.6)	(64.5)	-	(210.1)
Transfers	0.3	3.6	-	3.9
Closing balance	1,908.6	382.3	0.5	2,291.4

	2008			
	Dx Plant	General Plant	Other	Total
Opening balance	1,908.6	382.3	0.5	2,291.4
Depreciation	130.7	66.3	-	196.9
Retirements	(30.1)	(20.7)	-	(50.8)
Transfers	0.3	-	-	0.3
Closing balance	2,009.5	427.8	0.5	2,437.9

d. Hydro One Distribution has no Leave to Construct projects under section 92. All Hydro One Section 92 applications before the Board are by Hydro One Transmission.

Title

CLASSIFICATION OF EXPENDITURES
October 31, 2000

Policy Statement

Hydro One shall classify its expenditures between capital and OM&A expense so as to allocate costs to specific accounting periods in a manner that appropriately matches those costs with related future economic benefits. Accordingly, expenditures that are material in amount and which meet the definition of an asset shall be capitalized.

Scope

This policy applies to all operations and subsidiaries of Hydro One Inc., whether regulated or unregulated.

Corporate Requirements

GENERAL REQUIREMENTS:

- Expenditures incurred for the following general purposes shall be capitalized, where above established materiality limits:

  a) purchase, construction and commissioning of specific assets that will provide future economic benefits;
  b) design and development of specific assets that will provide future economic benefits;
  c) additions to specific assets; and
  d) betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific assets.

  Current materiality limits are provided in Appendix A.

  Exception
  Materiality limits shall not apply to plant retirement units.

- Direct expenditures qualifying for capitalization include direct labour, direct materials and supplies, transportation costs, directly attributable external costs and fees, permits, and injuries and damages incurred in construction work (net of insurance recoveries).

  Indirect expenditures qualifying for capitalization include financing costs (i.e. for unregulated subsidiaries – (1) interest costs and for regulated subsidiaries - the regulator's allowance for funds used during construction), (2) attributable shared service costs (e.g. general engineering, administrative salaries and expenses, insurance and taxes), and (3) attributable depreciation of capital tools and transport and work equipment used in the capital project.

- Direct and indirect decommissioning, fixed asset removal and site restoration costs shall be charged to current operations (i.e. depreciation expense) as incurred unless specific accounting provisions have already been made. If a specific accounting provision has been made, such expenditures are to be charged to that accumulated balance sheet provision.

- In unusual cases, generally accepted accounting principles require the deferral and amortization of certain specific costs when future economic benefits can be directly attributed and are reasonably assured. Recognition of such deferred charges

requires a high level of accounting judgement and is potentially subject to inconsistent application. As such, deferred charge accounting treatments shall only be used in cases where the business facts are reviewed and approved by Corporate Finance.

- Materials, supplies and capital spares purchased for future usage are not immediately capitalized as in-service assets, nor are they immediately charged to operations. Materials, supplies and spare capital components are treated as inventories of stock for future consumption in Hydro One's operations, maintenance and construction programs. Materiality limits and business facts will determine the final accounting classification of these items as capital or OM&A.

SPECIFIC REQUIREMENTS:

Assets Not Owned by Hydro One

Expenditures on assets not owned by Hydro One but providing future economic benefits shall be capitalized, provided there is assurance that Hydro One has the right to use the asset or that the asset's future economic benefits will continue to be accrue to Hydro One.

Carrying Charges

Carrying charges shall be capitalized as asset acquisition costs as long as a project is undergoing design and construction activities and there is a reasonable expectation of completion and recovery. Carrying charges shall be charged to current operations once a project is either declared in-service or is declared as ready for service.

Carrying charges related to cancelled capital projects and capital facilities with rescheduled in-service dates shall be accounted for in accordance with the Corporate Financial Policy, "Cancelled Capital Projects and Capital Projects with Rescheduled In-service Dates."

Common Facilities

A portion of the cost of common facilities in a multiple-asset facility or asset shall be transferred to fixed assets in service at the same time as each of the associated major assets is declared in service and in proportion to the total output or benefit represented by that asset.

Computer Software Costs

System software expenditures shall be capitalized. Major applications software projects with total acquisition and enhancement expenditures in excess of established materiality limits, and with an expected future useful life exceeding two years, shall be capitalized. All other software expenditures shall be charged to current operations as incurred.

Software acquisition and enhancement costs shall include:

- Software purchase costs (including internal and external customization charges);
- Initial and ongoing payments for licensing agreements to use external software packages where the license period exceeds two years;
- Attributable development costs where software is internally developed; and
- Testing, data purchase and loading costs, commissioning, and documentation.

Software-related expenditures for existing data clean up prior to loading are not capitalized as they represent a repair of existing data. Business process reengineering costs that are directly related to certain computer systems shall be charged to current operations as incurred, as these reengineering costs are not an integral component of the software.

Major software projects that consist of several related but independent modules should be placed in service as each module meets in-service criteria.

Contributions in Aid of Construction

Fixed assets funded in whole or in part by external parties are capitalized at cost. Contributions in Aid of Construction received from external parties should be recorded in capital accounts as a specific asset contra account (i.e. credit account) offsetting the asset cost in whole or in part.

Land and Land Rights

Capitalized land costs include direct purchase costs including appraisals, fees, commissions surveys, title search and registration, and net clearance costs of unwanted buildings. Costs for first clearing, grading and damage costs related to construction and installation of plant are ultimately capitalized as part of the cost of fixed assets constructed on the land, rather than as an integral cost of the land.

Capitalized land rights include Hydro One's cost of acquiring rights, interests and privileges in land owned by others.

Net profits from sales of timber or other resources located on land or rights of way shall be credited to the cost of the land.

Leases

Capital and operating leases shall be accounted for in conformance with the requirements of section 3065 of the Handbook of the Canadian Institute of Chartered Accountants.

Major Infrequent Repairs

The accounting treatment of unbudgeted infrequent repairs which are material in amount shall be referred to Corporate Finance to determine whether a special regulatory accounting treatment should be sought. All other expenditures for repairs shall be expensed as incurred.

Major Transformation Equipment

The cost of major transformation equipment to be installed at a current construction project shall be transferred to the project capital work order at the time the equipment is delivered to site.

The cost of major transformation equipment for installation at a future construction project shall be transferred to the "Assets Held for Future Use Account" at the time the equipment is delivered to a storage site. While in this account, interest on the equipment will be charged to current operations until the equipment is delivered to a current construction project.

The cost of major transformation equipment purchased as power system operating spares shall be treated as if the equipment is placed in service at the time it is delivered to a storage site.

Mobile Distribution Station Equipment

The costs, including depreciation, rental, connection and disconnection, and moving such mobile distribution equipment, shall be charged to the related capital project in cases where the equipment is used to maintain service to customers during extensive re-arrangements of Hydro One distribution stations. The cost of mobile equipment used for other purposes shall be charged to current operations.

Penalty Payments

Contract penalty payments related to the design and construction of Hydro One fixed assets should be charged to current operations.

Plant Retirement Units (PRU's)

Expenditures for the creation or replacement of a PRU shall be capitalized. Expenditures to replace a component of a PRU or for the physical removal or relocation of a PRU, shall be charged to current operations or, where previously provided for, to the appropriate provision account (e.g. asset removal), as incurred.

Premium Labour Costs

Premium labour costs incurred in performing work during an emergency, whether the base work is of a capital, removal or OM&A nature, shall be charged to operations as incurred.

Project Development Costs

Project development and pre-engineering costs shall be capitalized once a preferred alternative has been selected and approved. All general planning and specific project planning costs incurred prior to the approval of a preferred alternative shall be charged to current operations as incurred.

Research and Development Costs

Research and development expenditures shall be accounted for in accordance with the recommendations of the CICA Handbook Section 3450, "Research and

Development Costs." Specific capital project development expenditures shall be accounted for under the "project development costs" provision found elsewhere within this policy.

Temporary Facilities Built to Assist Construction

The cost of building and removing such facilities, including material cost less salvage, shall be capitalized as part of the cost of the related capital construction project.

Temporary Operating Plant

The cost of constructing such temporary operating assets shall be capitalized as operating plant if total cost exceeds established materiality levels and if the estimated service life exceeds two years.

Training Costs

Training costs related to assets that are new to Hydro One's operations or which are otherwise unconventional in nature, and which can be directly associated with those specific tangible assets, shall be capitalized as an integral cost of those assets. All other training costs, including those associated with capitalized computer software projects, shall be charged to current operations as incurred.

Definitions

Many definitions relevant to this policy are provided in the Canadian Institute of Chartered Accountants' Handbook, in section 1000 (Financial Statement Concepts), section 3060 (Capital Assets), section 3065 (Leases) and section 3450 (Research & Development).

Addition:

An expenditure made to add to an existing capital asset.

Allowance for Funds Used During Construction (AFUDC):

AFUDC represents an allowance for financing costs attributable to the construction or acquisition of a regulated fixed asset. The allowance, which must be approved by the rate regulator, is capitalized as an integral cost of the asset.

Asset:

Economic resources controlled by an enterprise with three essential characteristics: (1) they embody future economic benefits; (2) the enterprise can control access to the benefit, and (3) the transaction giving rise to the future economic benefit has already occurred.

Betterment:

Expenditure made to enhance the service potential of a capital asset over its original specification. This can be accomplished by an increase in service life, increase in output,

reduction in operating costs etc.

***Capital Asset**:*

Fixed assets or property, plant & equipment meeting all three of the following criteria: (1) held for the production or supply of goods or services, for rental, for administrative purposes, or for the development, construction, maintenance or repair of other capital assets; (2) acquired, constructed or developed with the intention of being used on a continuing basis, and (3) not intended for resale in the usual course of business.

***Carrying Charges**:*

Carrying charges are recurring costs associated with the possession or ownership of property. They include such costs as interest, utilities, security, insurance, payments in lieu of property taxes, and storage costs.

Commissioning (or Testing):

The need for commissioning or testing work occurs whenever an asset is constructed or extensively modified. Commissioning work includes pre-start checks and inspections, startup of equipment and systems, functional tests, identification and resolution of problems, running parallel systems in the case of major computer software, and bringing the unit up to full capacity with an acceptable operating reliability. The commissioning or testing period for an asset unit normally starts well prior to the end of construction and continues to the in-service date.

Expenditure:

A cash disbursement, liability incurred or transfers of property for the purpose of obtaining goods or services.

Fixed Asset:

Generally synonymous with "capital asset."

Future economic benefits:

Future economic benefits are generally evidenced by an increase in net cash inflow. Increased revenues reduced operating costs, or some combination of the two can cause this.

Future Use Asset:

An asset is a future use asset when it is acquired for future use in either a capital or OM&A project. Future use assets are not charged with capitalized interest (or AFUDC for regulated assets), nor are they depreciated or amortized.

In-service Asset:

An asset is declared in-service when ready for commercial use. Generally this point is

evidenced by the commencement of the asset's contribution of net economic benefits to the enterprise. Capitalization of interest (or in the case of regulated enterprises, capitalization of the allowance for funds used during construction) ceases at the in-service date and depreciation or amortization commences.

Major Infrequent Repair:

Occasionally, a significant repair is required to operating plant which does not result in the replacement of a plant retirement unit and does not result in an addition to, or the betterment of, an asset. A repair could be considered unusual if it is non-recurring, has not been budgeted for and is not expected to recur during the service life of the related asset. If the cost of such a repair is large enough to significantly distort net income in the year in which it occurs, it may require special consideration to determine whether an extraordinary regulatory accounting treatment is required.

Maintenance:

The ongoing cost of keeping a capital asset in good operating condition.

Materiality Limit:

For the purposes of classifying expenditures as capital additions or OM&A, Corporate Finance maintains specific quantitative limits to guide decision-making. Expenditures in excess of these preset limits, and which meet subjective criteria to be considered as capital assets, are capitalized. All other expenditures are charged to current operations as incurred.

Penalty Payment:

Any additional payment made to suppliers as a result of canceling or changing the terms of a contract or agreement to purchase which does not result in the acquisition of additional tangible goods, equipment or services of equivalent value. Examples of penalty payments are contract cancellation payments, shop under-absorption charges, loss of profit claims, and interest costs incurred by vendors. Costs arising because of errors in the design and construction process are not considered to be penalty payments. Likewise, storage costs are not considered to be penalty payments – they are treated as carrying charges.

Plant Retirement Unit (PRU):

The smallest unit of capital asset that is recorded in the accounts for the purposes of retirement or replacement.

Preferred Alternative:

The preferred alternative is the point at which pre-engineering or capital project development costs begin to be capitalized. A preferred alternative exists when management with sufficient authority provides expenditure approval for a specific capital project.

Project Development Costs (or 'Pre-engineering Costs'):

Costs incurred during the planning and approval phases of a capital project, prior to detailed design and construction.

Ready for Service Asset:

An asset is ready for service when construction activity has ceased and the asset is capable of providing net economic benefits but is constrained in some manner from making this contribution. Capitalization of interest (or in the case of regulated enterprises, capitalization of the allowance for funds used during construction) ceases when the asset becomes ready for service. Depreciation or amortization does not commence until the asset is actually in-service.

Repair:

The cost of corrective action required to return a capital asset to good operating condition.

Replacement:

The act of replacing one capital asset or PRU with another.

Temporary Operating Plant:

Plant constructed specifically to provide or to maintain service to customers and which will eventually be replaced by permanent facilities. Temporary plant is built to provide immediate relief to the operating system until permanent facilities are warranted or otherwise made available.

Temporary Facility:

A facility built, used, and dismantled during the progress of a Hydro One capital construction project. A temporary facility is required to assist construction or extensive re-arrangements to operating plant. An example is a temporary sub-station.

Appendix A - Materiality Limits for Capital Additions

Transmission stations - $50,000
Transmission line sections - $50,000
Communication line sections, stations or systems - $10,000
Distributing stations or line sections - $5,000
Administrative or service buildings - $5,000
Minor fixed assets - $2,000
Retail system facilities - none established
Administrative application software - $2 million total project cost

Functional Responsibility

Hydro One Networks Inc. – Corporate Finance

Ontario Energy Board (Board Staff) INTERROGATORY #8 List 1

Interrogatory

8. Ref: Exhibit D1 Tab 3 Schedule 1 – Carryover Projects/ Issue 4.2

Please identify carryover projects, on an individual basis (i.e., one project at a time, including $ amount carried over from one year to another), for the 2006 actual, 2007 bridge, and 2008 test year.

CONTINUITY SCHEDULE OF CARRYOVER PROJECTS

Type of the Carryover Project (e.g. Underground Cable replacement, smart meters, etc.)	**Start Date**	**End Date**	**$ Carryover from 2005 to 2006**	**% Carryover from 2005 to 2006 to total 2006 Capital expenditure**	**$ Carryover from 2006 to 2007**	**% Carryover from 2006 to 2007 to total 2007 Capital expenditure**	**$ Carryover from 2007 to 2008**	**% Carryover from 2007 to 2008 to total 2007 Capital expenditure**
1								
2								
3								
4								
5								
6								

For each project documented in the above table, please explain why the project was carried over (or is expected to be carried over). Please also specify if the project is one-time or ongoing.

Response

The following table depicts material projects ($1M or greater) scheduled to be undertaken over two or more years. Work is planned to occur over several years (initial year plus carryover years) for such reasons as to accommodate the size and complexity of the project, availability of outages and other project planning factors that affect multi-year projects. All are one-time projects, although Smart Meters could be thought of more as a longer-term program than a project.

1

Type of the Carryover Project (e.g. Underground cable replacement, smart meters, etc.)	Start Date	End Date	$ Carryover from 2005 to 2006	% Carryover from 2005 to 2006 to total 2006 Capital expenditure	$ Carryover from 2006 to 2007	% Carryover from 2006 to 2007 to total 2007 Capital expenditure	$ Carryover from 2007 to 2008	% Carryover from 2007 to 2008 to total 2007 Capital expenditure
Minden TS 87M1-87M4 Double Cir	2005	2007	$1,985,638	36%	$95,576	2%	$0	0%
Havelock TS 57M1 phase 5	2006	2008	$0	0%	$1,913,431	35%	$3,512,384	65%
Stayner TS Blue Mtn 2 New Feed	2006	2008	$0	0%	$135,195	3%	$4,056,034	95%
Everett TS 44 kV Feeders New	2005	2007	$2,254,234	69%	$915,058	28%	$0	0%
HAVELOCK TS 57M1 FEEDER REHAB	2006	2007	$0	0%	$2,258,883	69%	$0	0%
BELLE RIVER DX COSTS	2006	2006	$3,101,819	100%	$0	0%	$0	0%
Longlac TS 16M1 part 3 of 5	2005	2007	$2,354,475	80%	$212,962	7%	$0	0%
Bruno Knoepfli-Z2 Relocate	2005	2007	$35,974	1%	$2,838,724	97%	$0	0%
Kingsville TS 3M10 Feeder Ext	2005	2007	$54,100	2%	$2,776,267	98%	$0	0%
EXTEND MUSKOKA TS M9 FEEDER	2005	2007	$1,718,637	62%	$938,554	34%	$0	0%
Allenburg TS M6 Reconf	2005	2008	$12,635	0%	$1,155,870	43%	$1,455,347	54%
Everett TS Capital Contributio	2005	2007	$11,495	0%	$2,310,000	88%	$0	0%
WILSON TS M15 FEEDER REHAB	2005	2007	$784,083	31%	$1,585,810	62%	$0	0%
TIMMINS VIMY DS VOLTAGE CONVES	2005	2007	$608,532	25%	$14,296	1%	$0	0%
ORANGEVILLE TS M2 FEEDER REHAB	2005	2007	$1,801,623	74%	$94,447	4%	$0	0%
SHINING TREE DS F3 FEEDER REHB	2005	2007	-$102,107	-4%	$997,171	41%	$0	0%
SIDNEY TS FEEDERS REHAB	2005	2008	$34,718	1%	$182,256	8%	$2,047,523	88%
LINDSAY TS D4M7 FEEDER REHAB	2005	2007	$938,339	42%	$192,461	9%	$0	0%
MTO Hwy 11 Katrine Relocate	2005	2007	$2,066,066	94%	$84,715	4%	$0	0%
Belle River TS M2 to Haycroft	2007	2008	$0	0%	$0	0%	$2,061,151	96%
LAUZON TS M27 FEEDER RELIEF	2005	2007	$880,871	42%	$156,915	8%	$0	0%
TAUNTON DS VOLTAGE CONVERSION	2005	2007	$148,291	7%	$6,485	0%	$0	0%
Fort Frances TS 22M1 Phase 3	2006	2008	$0	0%	$165,089	8%	$1,841,677	92%
Honda Relocate 9M11	2006	2007	$0	0%	$1,874,957	96%	$0	0%
GREY BRUCE RELOCATE PHASE 2	2006	2007	$0	0%	$505,433	26%	$0	0%
Timmins TS M9 Feeder Ext	2006	2008	$0	0%	$6,890	0%	$1,886,160	98%

Type of the Carryover Project (e.g. Underground cable replacement, smart meters, etc.)	Start Date	End Date	$ Carryover from 2005 to 2006	% Carryover from 2005 to 2006 to total 2006 Capital expenditure	$ Carryover from 2006 to 2007	% Carryover from 2006 to 2007 to total 2007 Capital expenditure	$ Carryover from 2007 to 2008	% Carryover from 2007 to 2008 to total 2007 Capital expenditure
Minden TS M1 Year 3 Const	2006	2008	$0	0%	$10,732	1%	$1,772,448	99%
Rockland Supply Reinforcement	2005	2007	$1,178,973	70%	$72,865	4%	$0	0%
SUPLY MT ALBERT DS - BROWN HILL	2005	2007	$299,594	18%	$1,332,296	82%	$0	0%
Ingersol TS 38M44 Voltage Conv	2005	2008	$1,719	0%	$23,885	1%	$1,558,000	97%
Armitage M12 Supply to Stoufv	2006	2008	$0	0%	$24,932	2%	$1,506,329	95%
Belle River West TS Egress	2005	2007	$1,309,770	84%	$35,478	2%	$0	0%
Change Lively DS Primary Volta	2005	2006	$55,108	4%	$0	0%	$0	0%
Owen Sound TS C2M25	2005	2006	$1,429,370	94%	$0	0%	$0	0%
Gardiner TS 44 kV Feeders - RF	2005	2006	$173,347	12%	$0	0%	$0	0%
Dorset DS F2 Feeder Upgrades	2006	2008	$0	0%	$162,405	12%	$1,166,682	84%
Kingsville TS M3 M6 Rehab	2006	2008	$0	0%	$27,281	2%	$1,322,608	97%
Lindsay TS D4M7 phase 4	2006	2008	$0	0%	$24,817	2%	$1,288,065	96%
Minden TS M1 QC37X8732 Rehab	2005	2007	$902,822	71%	$104,209	8%	$0	0%
LONGLAC TS 16M1 FEEDER	2005	2006	$65,528	5%	$0	0%	$0	0%
TAYLOR KIDD DS-ADD TX & FEEDER	2005	2007	$599,947	49%	$13,923	1%	$0	0%
Minden TS M2 44 kV Feeder	2005	2007	$101,495	8%	$944,235	77%	$0	0%
Timmins Moneta DS Voltage Conv	2006	2008	$0	0%	$67,883	6%	$1,119,059	92%
PINESTONE DS F1 F2 F3 COORD	2005	2007	$100,552	8%	$3,600	0%	$0	0%
Bloomington RS New	2005	2007	$175,924	15%	$1,000,389	84%	$0	0%
THAMESVILLE WEST-NEW MVA	2005	2006	$4,332	0%	$0	0%	$0	0%
Sub Cable Program Z6 2060	2005	2007	$653,203	55%	$11,472	1%	$0	0%
Norfolk TS New M4 Feeder	2006	2007	$0	0%	$1,143,253	96%	$0	0%
44KV Recloser Inventory 24 Unt	2006	2007	$0	0%	-$56,762	-5%	$0	0%
TAUNTON DS CONVERSION	2005	2006	$302	0%	$0	0%	$0	0%
MTO Relocates Hwy 11	2005	2007	$52,030	5%	$1,036,557	91%	$0	0%
2004 SEAFORTH TS 21M5 FEEDER	2005	2006	$259,482	24%	$0	0%	$0	0%
Lindsay TS D4M7 Year 3 const	2006	2007	$0	0%	$948,085	91%	$0	0%
Baseline and Green Rd Relocate	2006	2007	$0	0%	$971,844	95%	$0	0%

Type of the Carryover Project (e.g. Underground cable replacement, smart meters, etc.)	Start Date	End Date	$ Carryover from 2005 to 2006	% Carryover from 2005 to 2006 to total 2006 Capital expenditure	$ Carryover from 2006 to 2007	% Carryover from 2006 to 2007 to total 2007 Capital expenditure	$ Carryover from 2007 to 2008	% Carryover from 2007 to 2008 to total 2007 Capital expenditure
Kent TS New M6 Feeder	2005	2007	$47,715	5%	$900,405	94%	$0	0%
CROYDON DS F2 VOLTAGE CONVERSI	2005	2006	$229,317	24%	$0	0%	$0	0%
Muskoka TS 30M1	2005	2007	$785,490	82%	$152,981	16%	$0	0%
KILLALOE DS F1 FEEDER REHAB	2005	2008	$4,368	0%	$24,201	3%	$905,121	97%
ARMITAGE TS M32	2005	2007	$85,273	9%	$842,380	91%	$0	0%
Minden TS M1 2nd year const	2006	2007	$0	0%	$783,050	86%	$0	0%
MTO Hwy 11N Sundridge	2006	2007	$0	0%	$848,950	97%	$0	0%
Parry Sound TS Split M1 Feeder	2006	2007	$0	0%	$848,168	97%	$0	0%
CENTRALIA TS 24M1 LOAD RELIEF	2005	2006	$31,507	4%	$0	0%	$0	0%
WILHAVEN DS F5 EXTENSION	2006	2007	$0	0%	$790,640	95%	$0	0%
WOODSTOCK TS 10M4 LINE EXTEND	2005	2007	$258,826	31%	$555,707	67%	$0	0%
CL A EST:SOUTH MARCH A9M6	2005	2006	$4,088	0%	$0	0%	$0	0%
CIS/CSS Hybrid Upgrade	2006	2008	$385,004	8%	$2,663,325	52%	$2,000,000	39%
CTI Upgrade	2005	2007	$3,320,070	60%	$720,563	13%	$0	0%
ACPI/WEP	2005	2007	$7,971,433	43%	$946,875	5%	$0	0%
Asset Data Collection and Data Mart	2005	2007	$810,852	36%	$898,060	40%	$0	0%
Smart Metering #	2005		$14,100,000	N/A	$76,700,000	N/A	$164,800,000	N/A
Cornerstone *	2007		$0	N/A	$60,400,000	N/A	$63,000,000	N/A

* Cornerstone supports both the Distribution and Transmission businesses.

Smart Meters is a long-term program.

Ontario Energy Board (Board Staff) INTERROGATORY #9 List 1

Interrogatory

Ref: Exhibit D2 Tab 2 Schedule 1 – Rate Base Summary/ Issue 4.1

Please complete the table below with the requested information.

RATE BASE SUMMARY

Rate Base Summary	**2006 Board Approved ($)**	**2006 Actual**	**Variance from2006 Board Approved ($)**	**2006 Actual ($)**	**2007**	**Variance from 2006 Actual($)**	**2007 ($)**	**2008 Test**	**Variance from 200 ($)**
Gross Asset Values at Cost									
Accumulated Depreciation									
Net Fixed Assets									
Allowance for Working Capital									
Rate Base									

Response

RATE BASE SUMMARY ($M)	**2006 Board Approved**	**2006 Actual**	**Variance from 2006 Board Approved**	**2006 Actual**	**2007 Bridge**	**Variance from 2006 Actual**	**2007 Bridge**	**2008 Test**	**Variance from 2007 Actual**
Gross Asset Values at Cost	5,550	5,680	130	5,680	6,022	342	6,022	6,450	428
Accumulated Depreciation	(2,127)	(2252)	(126)	(2252)	(2,310)	(58)	(2,310)	(2,365)	(55)
Net Fixed Assets	3,423	3,428	5	3,428	3,712	284	3,712	4,085	373
Allowance For Working Capital	288	292	4	292	302	10	302	297	(5)
Rate Base	3,712	3,720	8	3,720	4,014	294	4,014	4,382	368

Ontario Energy Board (Board Staff) INTERROGATORY #10 List 1

Interrogatory

10. Ref: Exhibit D1 Tab 1 Schedule 2 – Distribution System Assets / Issue 4.1

Please complete the table below identifying the actual or projected asset values for each of the classes of assets for the period 2002 to 2007.

Hydro One Distribution System Assets							
		2002	2003	2004	2005	2006	2007
Asset Values ($M)							
Secondary Distribution Feeders	48,000 km						
Poles (line supports)	1.65 million						
Distribution Stations	931						
Regulating Stations	75						
Station Transformers And Regulators	1,477						
Pole-mount & Pad-mount Transformers	475,000						

Response

Hydro One Distribution System Assets							
	2006 Values	2002	2003	2004	2005	2006	2007
		Asset Values ($M)					
Secondary Distribution Feeders	48,000 km	202.3	212.1	227.7	238.1	252.1	269.6
Poles (line supports)	1.65 million	1,368.3	1,443.6	1,503.1	1,568.2	1,664.9	1,753.2
Distribution Stations	931	290.0	294.2	297.3	307.6	316.4	316.8
Regulating Stations	75	26.6	27.1	27.3	28.4	28.5	32.8
Station	1,477	112.2	114.4	117.2	126.6	131.3	136.8

Hydro One Distribution System Assets							
	2006 Values	2002	2003	2004	2005	2006	2007
		Asset Values ($M)					
Transformers and Regulators							
Pole-mount & Pad-mount Transformers	475,000	278.4	301.5	332.8	364.4	396.8	435.3

1

Ontario Energy Board (Board Staff) INTERROGATORY #1 List 11

Interrogatory

Ref: Exhibit D1 Tab 1 Schedule 3 – Working Capital / Issue 4.1

a. On December 18, 2007, the Federal Government reduced the Goods and Services Tax (GST) to 5% effective January 1, 2008. Please provide updates to Tables 1 and 2 reflecting the GST reduction.
b. In Table 1 of Exhibit D1 Tab 1 Schedule 3, please provide the unit cost for energy used in the calculation of the projected cost of energy of $1,959.3M for the test year 2008.
c. For years 2002 through 2008, please provide a table listing the rate base, working capital and working capital as a percent of rate base.
d. What is the percentage increase in the 2008 test year rate base that wouldresult from a 1% increase in the cost of power?
e. Please provide a description of "Environment (or Environmental) Cost" category as used in the determination of Working Capital.

Response

a. Table 1 and Table 2 updated to reflect GST reduction to 5%.

Table 1
Distribution Net Cash Working Capital Requirement
(All Data in $M Except Lead/Lag Days)

	Revenue Lag (Days)	**Expense Lag (Days)**	**Net Lag (Lead) (Days)**	**2008 Test Year Amount**
	(A)	(B)	(C)	(D)
Expenses				
Cost of Power	68.41	32.96	35.45	1,959.3
OM&A Expenses	68.41	16.87	51.54	477.7
Removal Costs	68.41	15.69	52.72	22.8
Environment Costs	68.41	15.69	52.72	7.9
Interest on Long-term Debt	68.41	74.66	(6.25)	132.9
Income & Capital Tax	68.41	15.61	52.8	50.2
Total				**2,650.8**
GST (See Table 2)				31.5
TOTAL AMOUNTS PAID / ACCRUED				**$2,682.3**

Working Capital Required (Calculations based on above values, for each expense category, calculated using the following formula: Col (D)*Col (C)/366)	
Cost of Power	189.8
OM&A Expenses	67.3
Removal Costs	3.3
Environment Costs	1.1
Interest on Long-term Debt	(2.3)
Income & Capital Tax	7.2
Total	266.4
GST (See Table 2)	5.6
NET WORKING CASH REQUIRED	**$272.1**

Table 2
Distribution Summary of GST Cash Working Capital Requirement
(All Data in $M Except Lead-Lag Days)

GST Category	**2008 Test Year**	**5% GST Projection**
	(A)	(B)
Revenue	3,026.1	151.3
Cost of Power	(1,959.3)	(98.0)
OM&A Expenses	(187.8)	(9.4)
Removal Cost	(22.8)	(1.1)
Environmental Cost	(7.9)	(0.4)
Capital	(219.1)	(10.9)
TOTAL		**$31.5**
GST (Benefit) Cost	**Expense Leads (Days)**	**GST Amounts**
	(C)	(D)
The values shown in the Col (D) labeled "GST Amounts" are calculated using the expense leads shown in Col (C) divided by 366 and multiplied by the 5% GST projected amount in Col (B)		
Revenue	20.20	8.3
Cost of Power	43.08	(11.5)
OM&A Expenses	36.88	(1.0)
Removal Cost	44.50	(0.1)
Environmental Cost	44.50	(0.0)
Capital	44.50	(1.3)
TOTAL		**($5.6)**

b. The unit price used to calculate the cost for energy projected cost of energy of $1959.3M for the test year 2008 was $0.0767/kWh.

c.

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Bridge	2008 Test
Working Capital ($M) (includes Material & Supplies inventory)	294	298	315	331	292	302	297
Rate Base ($M)	3,095	3,239	3,419	3,579	3,720	4,014	4,382
Working Capital: Rate Base	9.5%	9.2%	9.2%	9.2%	7.9%	7.5%	6.8%

d. A 1% increase in the cost of power in the 2008 test year would result in a $2 million increase in rate base.

e. The "Environment Cost" category includes the 2008 expected cash expenditures required to remediate past environmental contamination, specifically for remediation of contaminated lands and the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment. These expenditures are included in the working capital calculation because they represent a use of cash in 2008 even though they are classified as an amortization expense.

Ontario Energy Board (Board Staff) INTERROGATORY #12 List 1

Interrogatory

Reference: Exhibit D1 Tab 1 Schedule 4 – Inventory Levels/ Issue 4.2

On page 2, Hydro One states, "Over the 2004 – 2006 period, particularly in 2006, annual inventory levels excluding smart meters increased by 44%. Further slight increases are expected over 2007 to 2008 period and onwards".

a. Please provide and quantify the cost drivers responsible for the 44% increase in inventory levels.
b. What percentage of the increase in inventory levels can be attributed to the market increase in price of steel and other commodities versus the change in the level of inventory?
c. What inventory control methods has Hydro One deployed to manage inventory levels? Please also state the financial implications of these methods on inventory management and inventory control.
d. Has Hydro One conducted benchmarking and best practice study regarding the inventory levels with other similar size North American and Canadian distributors? If yes, then please file any studies conducted since 2005.

Response

a. The 44% increase in inventory cost levels of $6.9M is primarily driven by the cost increase of transformers and conductors. Three major commodities (transformers, conductors and poles) represent ~75% of our 2006 YE inventory. Of the $6.9M increase about 95% or $6.5M can be attributed to the increased material costs for transformers ($3.4M of the $6.5M) and conductors ($3.1M of the $6.5M), with the remaining 5% (or $0.4M) due to increased volumes.

b. See (a), above.

c. Hydro One utilizes a Distribution Requirements Planning tool, which forecasts monthly demand requirements based on historical usage, and on current and future demand identified in the system, and replenishes stock based on these forecasts. We have not carried out a comparison of inventory levels arising from our methodology to levels which arise from other methodologies. Hydro One believes that there would be little value in conducting analysis of this nature since experience has shown that

the methodologies utilized by Hydro One have resulted in adequate availability of equipment, with no excessive backlog in inventory levels.

d. No. Hydro One has not conducted a benchmarking and best practice study regarding the inventory levels with other similar sized North American and Canadian distributors. Hydro One believes that there would be little value in conducting such a detailed best practice study, given the unique characteristics of the highly dispersed Hydro One Distribution asset base and the integrated nature of the Transmission and Distribution businesses owned and operated by the company.

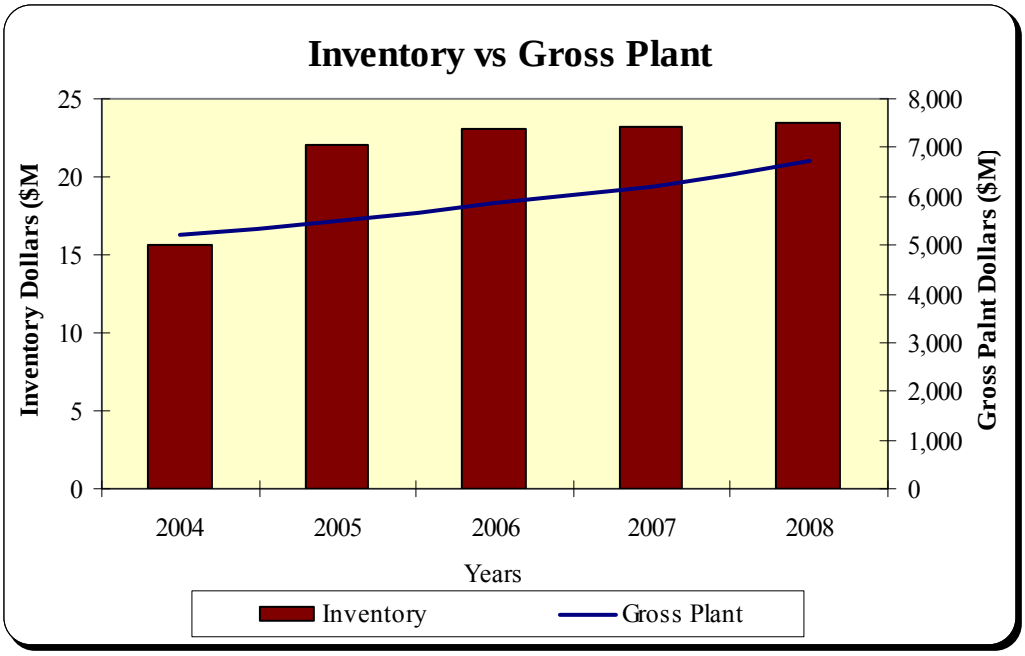
Ontario Energy Board (Board Staff) INTERROGATORY #13 List 1

Interrogatory

13. Ref: Exhibit D1 Tab1 Schedule 4 – Inventory/ Issue 4.2

Please provide a graph of Inventory ($) against Gross Plant ($) for each of years 2004 through 2008.

Response



Ontario Energy Board (Board Staff) INTERROGATORY #14 List 1

Interrogatory

Ref: Exhibit D1 Tab 2 Schedule 1 – Asset Condition Assessment and Analysis
Issue 4.8
Hydro One states "[Asset Condition Assessment] practices are based on studies carried out by Acres International Ltd., comparisons with other members in the electrical utility industry and expert opinion available within Hydro One".

a. Please provide copies of any recent studies conducted by Acres International which Hydro One has relied on in assessing the condition of its assets.
b. Please provide copies of any internal or external reports involving comparisons with other members in the electrical utility industry which Hydro One has relied on in assessing the condition of its assets.

Response

a) The "Asset Condition Assessment Study Summary Report of Distribution Assets" is the most recent study completed by Acres International for Hydro One Networks Inc. (Attachment A)

b) Other reports that have been used are:

1. Industry Best Practices Review for Hydro One, May 22, 2006, EPRI Solutions. (Attachment B)

2. 2008 Vegetation Management Program Review, March 12, 2008, Hydro One Networks Incorporated. (Attachment C)

Note: All the following CEA Technologies Inc. reports are proprietary in nature and therefore cannot be provided.

3. Distribution Power Line Inspection Training and Standards, August 2006, CEA Technologies Inc. Report No. T044700-5058

4. Asset Management Practices of Leading Distribution Utilities, April 2006, CEA Technologies Inc., Report No. T044700-5055

5. Replacement/"End of Life" Criteria for Distribution System Assets, February 2008, CEA Technologies Inc, Report T074700-5067 (note this is not yet available for purchase)

Asset Condition Assessment Study Summary Report of Distribution Assets

By

Acres International Limited

July 2005

This report is an update to a March 2003 report prepared by Acres International Limited, Canada in association with EA Technology Limited, UK, (Consultants) for Hydro One Distribution.

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Any reference in this report to any specific process or service by trade name, trademark, manufacturer or otherwise does not necessarily constitute or imply its endorsement or recommendation by Hydro One Distribution or its Consultants.

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Executive Summary

E.1 Introduction

In preparation for effectively rationalizing Hydro One Distribution's sustainment based work programs the company has undertaken a major condition assessment program for its Distribution (Dx) Assets. Since the inception of the asset management organization, Hydro One Distribution has reviewed the data available within its maintenance databases, identified additional data required to facilitate an objective appraisal of asset condition, and undertaken additional condition assessment surveys as necessary to collect the critical mass of asset condition data needed to plan its sustainment work programs.

This report contains a review of the overall asset condition assessment (ACA) process adopted by Hydro One Distribution, and documents the evaluated condition of the total population of Distribution assets, based on condition criteria and end-of-life criteria that are indicative of asset condition and consistent with industry practices.

The Distribution assets were grouped into 20 asset classes and prioritized into three categories, Priority 1 (P1), Priority 2 (P2), and Priority 3 (P3), based on their value to the business (in terms of reliability, customer, finance, health & safety, regulatory/legal/environment) and importance of acquiring the condition information. P1 assets (5 asset classes) represent the highest priority assets and are of high value (in terms total sustainment program expenditures) and high risk to the business. P2 assets (6 asset classes) are second in priority with moderate value and high risk; and finally P3 assets (9 asset classes) are lowest in priority with lower value and risk to the business. This report presents the condition assessment results of the P1 and P2 assets. For the low priority P3 assets only a review of industry practices is presented – any available condition assessment was not assessed because of the lower priority of these assets.

This report has been prepared by Acres International Limited (Acres) of Oakville Ontario. The analysis and report has been prepared in consultation with Hydro One Distribution's staff specialists, but the report and its conclusions are based on the findings of the consultant. For one asset group, Distribution Station Land Assessment Remediation (Dx LAR), Hydro One Distribution prepared the report section, including the underlying analysis. This approach was adopted since the relevant analysis and reporting was well advanced at the time of project commencement and it was felt that in-house Hydro One Distribution specialists were best qualified to undertake the required analysis. The consultants in this case limited their involvement to auditing the process and analytical methods and the assessed condition results.

E.2 Process Review

In general, it has been found that Hydro One Distribution has undertaken a very careful and thoughtful evaluation of condition assessment needs, and has followed a steady and measured program of data collection to secure the information needed to assess the condition of its Distribution assets. The data collection methods, tools and technologies are generally appropriate to the task of measuring asset condition, providing the right data at an appropriate cost. The methods used by Hydro One Distribution have been found to be consistent with industry practices. The methods and procedures for data collection are

well documented in head office procedure documents and specifications for data collection services.

Except for a few exceptions that did not result in any significant impact to the ACA results, the identified data collection procedures have been executed according to specifications, and useable data has been collected and stored in centralized or distributed databases.

Hydro One Distribution is using this data appropriately, having adopted condition criteria that form a rational basis for asset decision-making. Hydro One Distribution has adopted methods of analysis that are consistent with industry practices in most cases, and are at the cutting edge of industry practices in several cases. With composite Health Indices for critical class of assets, as recommended by the consultant, Hydro One Distribution has established a coherent and rational basis for evaluating the overall condition of each Distribution asset owned by the company.

Tables E1 and E2 show an overall evaluation of the quality of the processes adopted by Hydro One Distribution, and the quality of the data found in the various databases.

	Benchmarking & Process Review			
	Utility Comparisons	**Process Viability**	**Data Availability**	**Health Index Developed**
Distribution Stations				
Transformers	1	1	1	Yes
Land Assessment & Remediation	1	1	1	Yes
Distribution Lines				
Wood Poles	1	1	1	Yes
Overhead Line Sections	1	2	3	Yes
Rights-of- Way	1	1	1	Yes

Assessment Shading:

	- Score of 1- 2	Very Good - No significant issues
	- Score of 3	Fair - Some gaps or issues
	- Score of 4-5	Poor - Significant gaps or issues

Table E1 Evaluation of Hydro One Distribution ACA Processes for P1 Assets

	Benchmarking & Process Review			
	Utility Comparisons	Process Viability	Data Availability	Health Index Developed
Distribution Stations				
Reclosers	1	2	4	Yes
Circuit Switchers and High Voltage Fuses	1	1	1	Yes
Sites and Structures	1	1	1	Yes
Mobile Unit Substations	1	1	3	Yes
Distribution Lines				
Submarine Cables	2	2	4	Yes
Underground Cables	2	2	4	Yes

Assessment Shading:

	- Score of 1- 2	Very Good - No significant issues
	- Score of 3	Fair - Some gaps or issues
	- Score of 4-5	Poor - Significant gaps or issues

Table E2 Evaluation of Hydro One Distribution ACA Processes for P2 Assets

The results of the industry comparisons require little discussion. In all cases, Hydro One Distribution is pursuing a program of asset condition assessment that is equal to or better than programs executed in forward-thinking utilities around the world. The ACA processes of Hydro One Distribution have largely been demonstrated to be viable, in the sense that the data collected and the uses made of it are entirely appropriate to support the spending decisions that Hydro One Distribution must make.

Composite Health Indices have been recommended for Hydro One Distribution use by the consultant for most of the asset groups. Health Indices provide a basis for assessing the overall health of an asset. Health Indices are based on identification of the modes of failure for the asset and its sub-systems, and then developing measures of generalized degradation or degradation of key sub-systems that can lead to end-of-life for the entire asset.

The data availability rankings require some clarification. The only assets ranked "poor" on this aspect were for Distribution Station Reclosers, Distribution Submarine Cables and Distribution Underground Cables. These information gaps are not inconsistent with other utilities.

The most common way of managing Distribution Submarine and Underground Cables is on a run-to-failure basis. However, it is valuable to identify demographic characteristics and historical performance for evaluating risk and it is recommended that Hydro One Distribution redefine their process for acquiring and managing data for these asset classes.

In the case of station reclosers Hydro One Distribution uses a time based maintenance program (i.e., a 6-year cycle) to maintain and refurbish them. After an assessment the recloser is either rebuilt to "Very Good" condition or replaced. However, detail information on the assessment is not collected. It is recommended that Hydro One Distribution start collecting more detailed condition information as it could then provide an ideal opportunity to implement a condition assessment process using a Health Index to identify end-of-life, estimate remaining life and establish optimal maintenance cycles.

E.3 Asset Condition Results

The condition of the Hydro One Distribution assets has been evaluated in all circumstances where viable condition criteria are in place and sufficient condition data exists. Health Indices have been calculated for every asset with a recommended Health Index formulation and sufficient condition data to satisfy the minimum requirements for application of that formulation.

The results of the asset condition assessments for the P1 and P2 assets are presented in Tables E3 and E4, based on the Health Index formulations and the extrapolated test results.

	ACA Results				
	Very Poor	**Poor**	**Fair**	**Good**	**Very Good**
Distribution Stations					
Transformers	1.7%	1.3%	3.6%	17.6%	75.8%
Land Assessment & Remediation	44.6%	--	--	--	55.4%
Distribution Lines					
Wood Poles	1.3%	2.8%	0.5%	0.9%	94.4%
Overhead Line Sections	--	--	--	--	--
Rights-of- Way(Line Clearing)	2.8%	24.4%	36.0%	23.6%	13.1%

Assessment Shading for "Very Poor" and "Poor" Categories:

	<1%	Limited deterioration
	1 to 5%	Increasing deterioration, attention required
	>5 %	Significant deterioration, requires diligent and timely attention

Table E3 ACA Condition Results for P1 Assets

	ACA Results				
	Very Poor	**Poor**	**Fair**	**Good**	**Very Good**
Distribution Stations					
Reclosers	--	--	--	--	--
Circuit Switchers	0.0%	0.0%	0.0%	8.3%	91.7%
High Voltage Fuses	--	26.5%	34.8%	38.7%	--
Sites and Structures	0.1%	1.8%	22.4%	40.2%	35.5%
Mobile Unit Substations	0.0%	7.1%	0.0%	71.4%	21.4%
Distribution Lines					
Submarine Cables	--	--	--	--	--
Underground Cables	--	--	--	--	--

Assessment Shading for "Very Poor" and "Poor" Categories:

	<1%	Limited deterioration
	1 to 5%	Increasing deterioration, attention required
	>5 %	Significant deterioration, requires diligent and timely attention

Table E4 ACA Condition Results for P2 Assets

For some asset groups, maintenance and condition data has been collected for virtually every individual asset owned by Hydro One Distribution. In other asset classes, a smaller proportion of the total asset base has been tested and/or inspected, and the size and nature

of the samples taken is sufficient to extend the results to the balance of the assets in that class through statistically relevant sampling.

A consistent approach has been used in developing the Health Index formulations, so that the meaning of the categories is broadly consistent across most assets except for Rights-of-Way, Land Assessment and Remediation (LAR), and Spares, for which a conventional end-of-life definition is not applicable.

In general terms, a "Very Poor" asset can be interpreted to be at or very close to end-of-life, requiring urgent attention in the form of a risk assessment potentially leading to asset replacement or a major overhaul. Assets in the "Poor" category can be interpreted as being close to end-of-life, requiring risk assessment potentially leading to replacement or significant maintenance expenditures in a 1 to 5-year time frame. Assets in "Fair" condition have experienced noticeable deterioration, but should survive at least another 5-10 years with regular maintenance and/or component replacements. Assets in the "Good" category can be considered to have at least 10 to 20 years of service left, given normal maintenance expenditures. Assets in the "Very Good" category should survive for more than 20 years, given normal maintenance expenditures.

As might be expected, the vast majority of the assets owned by Hydro One Distribution are ranked in "Good" or "Very Good" condition, meaning that these assets are generally being managed effectively and are being maintained in a condition suitable for many more years of service. The same conclusion may be drawn from the relatively small proportion of assets found in "Very Poor" or "Poor" condition.

In general, concerns exists for those assets that are exhibiting greater then 1% in the poor to very poor category, with more specific concerns highlighted below.

- Distribution wood poles, with about 4.1% (66,000 poles) being at or near end-of-life. These poles should be replaced over the next inspection cycle as they are identified taking into consideration criticality and consequence of failure. This level of deterioration is consistent with a mature wood pole plant that has a substantial number of poles entering the end of life category each year.
- Distribution Rights-of-Way (ROW), with about 27.2% of the ROW requiring tree clearing in about the next two years.
- Distribution Station Land Assessment & Remediation (DS LAR), has 44.6% of stations showing some level of contamination and based strictly on condition, is rated as very poor even through the risk may be low in some cases. As the consultant was not directly involved in evaluating the condition assessment details, the rating was based purely on "contamination" or "no contamination". As such, further analysis is recommended to assess the severity and impacts of the contamination. Hydro One Distribution has carried out additional risk assessment and this is discussed in greater detail in Section 3.1.2.
- Distribution Mobile Unit Substations (MUS), with 2 (7%) of the stations in poor condition. These stations are at risk of failing road certification within the next 5 years and will need refurbishment if they are to be kept in operation.

E.4 Field Audits

Field audits were undertaken in 2003 for most of the P1 and P2 assets, to ascertain the degree of conformance of data collection activities to defined procedures and practices, and the degree of conformance of observed conditions to recorded field data and stored data.

In general, the auditors found that data was being collected by field groups in accordance with specifications, and that there was good correlation between field observations and recorded data. Such minor discrepancies as were observed followed no discernible pattern, and it has been concluded that no bias has been introduced in the overall condition results as a result of these minor discrepancies. Given the relatively short time period (i.e. less than 2 years) since the completion of this 2003 audit study, it was determined that a new field audit for the 2005 update was not necessary.

SUMMARY REPORT

1. Introduction

Hydro One Distribution retained Acres to update the March 2003 comprehensive assessment of the condition of the Distribution assets owned by Hydro One Distribution. The investigation commenced in January of 2005 and was concluded in July 2005.

The scope of the project, as set out in Terms of Reference issued by Hydro One Distribution in January of 2005, is as follows:

1. Investigate the modes of degradation and failure for each of the asset classes in the Distribution systems owned by Hydro One Distribution.

2. Review the asset condition assessment processes employed by Hydro One Distribution to measure the condition of the assets, and benchmark these processes against those employed by other utilities around the world.

3. Recommend asset condition criteria, end-of-life criteria and Health Indices for use by Hydro One Distribution in their asset management activities.

4. Assess the adequacy of the available condition data in preparing an objectively verifiable assessment of asset condition, and recommend measures to close any identified gaps in the existing condition data.

5. Evaluate the condition of Hydro One Distribution's Distribution asset base, using the recommended criteria and the available condition data.

This Summary Report documents the methodology employed in the investigation and the philosophical approach used, along with summary results for all 20 Distribution asset classes.

Recognizing that to gather detailed condition information on every individual asset and every "nut and bolt" is both practically and economically infeasible, all Distribution assets were grouped into 20 asset classes and prioritized into three categories, Priority 1 (P1), Priority 2 (P2), and Priority 3 (P3), based on their value to the business (in terms of reliability, customer, finance, health & safety, regulatory/legal/environment) which determines the importance of acquiring the condition information. P1 assets (5 asset classes) represent the highest priority assets and are of high value (in terms total sustainment program expenditures) and high risk to the business. P2 assets (6 asset classes) are second in priority with moderate value and high risk; and finally P3 assets (9 asset classes) are lowest in priority with lower value and risk to the business. This report presents the condition assessment results of the P1 and P2 assets. Limited information is to be provided on the P3 assets because acquiring asset condition information on these assets is of "low" value for any of the following reasons:

- The assets are of low dollar value in terms of ongoing investments and it is not cost effective or practical to collect ACA information on these assets e.g. Distribution Line Fuses.

- When these assets fail, risks are considered relatively low and managed process exists to quickly identify and repair or replace assets that have failed, or are about to fail, e.g. pole-top transformers.

The assets included in each asset group (P1, P2 and P3) and the corresponding section numbers of the report dealing with these assets are listed in the following tables. It is noted that Acres completed the comprehensive asset condition assessment for all P1 and P2 assets in accordance with the scope of work, except for Dx Land Assessment and Remediation. In this case Hydro One Distribution wanted to understand the results internally prior to consultant involvement, however, Acres reviewed the findings of the internal study.

P1 Assets

	DESCRIPTION	SECTION NO.
Dx Stations	Dx Transformers and ULTCs	3.1.1
	Dx Land Assessment & Remediation (LAR)	3.1.2
Dx Lines	Dx Wood poles	3.1.3
	Dx Overhead Line Sections	3.1.4
	Dx Rights-of-Way (ROW)	3.1.5

P2 Assets

	DESCRIPTION	SECTION NO.
Dx Stations	Dx Station Reclosers	3.2.1
	Dx Station Circuit Switchers & HV Fuses	3.2.2
	Dx Station Sites and Structures	3.2.3
	Dx Mobile Unit Substations	3.2.4
Dx Lines	Dx Submarine Cables	3.2.5
	Dx Underground Cables	3.2.6

P3 Assets

	DESCRIPTION	SECTION NO.
Dx Stations	Dx Oil Circuit Breakers	3.3.1
	Dx Spares (Transformers and Switchgear)	3.3.2
	Dx AC/DC Service Equipment (Batteries and Chargers)	3.3.3
	Dx Switch and Fuse Feeder Protection	3.3.4
	Dx Oil Containment	3.3.5
	Dx PCB and Hazardous Waste	3.3.6
Dx Lines	Dx Line Switches	3.3.7
	Dx Line Reclosers	3.3.8
	Dx Line Transformers	3.3.9

2. Methodology

2.1 Asset Descriptions

A detailed description has been prepared for each of the 11 assets in the P1 and P2 and for some in the P3 asset classes investigated as part of this study. The descriptions focus on the nature of the assets, their function within the power system, and key characteristics of the assets including the critical subsystems that make up the assets.

2.2 Asset Demographics

Detailed demographics were prepared for all 11 assets in the P1 and P2 asset classes, focusing on the total population size of each asset, and the distribution of this population by various salient asset characteristics, such as asset types, operating characteristics (voltage ratings, current or power ratings), ages, and geographic locations. The objective of the demographic breakdown was to quantify population sizes within definable groupings, which then form the basis for extrapolation of sampled condition results to the respective target populations.

The source data for the Distribution demographic analyses was from a variety of data sources, including the Distribution Work Management system, Line Asset Surveys and the Distribution Station (DS) ACA Survey (for station assets). The consultant did not directly access the raw data, but instead relied on Hydro One Distribution staff to extract needed data.

2.3 Review of Asset Condition Assessment Process

Acres carried out a review of asset condition assessment processes for each of the P1 and P2 asset classes. This review was carried out in comparison with an idealized framework for a hierarchical and prioritized asset condition assessment process, as described in Section 2.3.1. The specific elements of the review include:

- Analysis of asset deterioration and failure modes,
- Description of the Hydro One Distribution condition assessment process,
- Review of industry practices,
- Benchmarking of Hydro One Distribution practices against industry practices,
- Recommendation of practices for use by Hydro One Distribution,
- Analysis and recommendation of composite Health Indices.

For P3 asset classes only a review of industry "practices" is carried out.

2.3.1 Overview of Asset Condition Assessment Processes

Throughout the world, electricity companies are undergoing major change due to privatization or deregulation. While the detail of these processes varies from country to country, some of the effects are almost universal. Essentially, the engineering activities of utility companies have been subject to much closer scrutiny and there is great pressure to reduce cost while maintaining or improving system performance. As a consequence of

this, there is greater need to provide technical and economic justification for engineering decisions and spending plans. The analysis outlined in this report specifically focuses on the technical justification, namely asset condition as it is considered by the industry and engineering judgment on the risks associated with certain condition levels. Engineering judgement with input from other utilities was applied to assess risks concerning performance, reliability, technical obsolescence, customers, health and safety, environment, etc.

This increased need for utilities has resulted in a need to understand the condition of assets in more detail than was previously necessary. Throughout the world, electricity companies are attempting to move towards condition-based management strategies for their major assets. This requires a very good understanding of the present condition and how this relates to future performance and end-of-life. While this is a very understandable and necessary approach, there are some significant difficulties in developing and implementing condition assessment processes to deliver the outcomes required.

Electricity distribution systems are made up of a very large number of individual components, which are widely distributed. Conventionally, in order to make a decision about the future of an individual asset, relatively detailed condition information is required. This immediately raises a very significant practical problem for electricity companies. To attempt to gather detailed condition information about every individual asset would be both practically and economically infeasible. In order to overcome this situation, a hierarchical approach to condition assessment must be applied, to enable prioritization and focused gathering of detailed condition information.

There are a number of ways in which this prioritization and focusing can be achieved. These include the use of existing knowledge and simple, low cost, condition assessment procedures to progressively identify items at high risk, so that resources necessary for detailed condition assessment can be concentrated on these items. Alternatively, a sampling approach may be adopted within definable subgroups of assets, again to limit the number of pieces of equipment subject to detailed condition assessment.

A) Review of Asset Deterioration & Degradation Processes

When considering asset condition assessment (ACA) it is important to understand the differences between defect management and regular maintenance versus long-term asset degradation and asset condition assessment.

Defects are usually well defined and associated with failed or defective components in the ancillary systems that affect operation and reliability of the asset well before end-of-life. These do not normally affect the life of the asset itself, if detected early and corrected. Defects are routinely identified during inspection and dealt with by maintenance activities to repair or replace failed components to ensure continued operation of the asset.

Long term degradation is generally less well defined and is not easily determined by routine inspection. The purpose of asset condition assessment is to detect and quantify long-term degradation and to provide some means of quantifying remaining asset life.

This includes determining assets that are "high risk" or are at or near end-of-life that will require major capital or maintenance expenditures to either refurbish or replace.

A good understanding of the asset degradation and failure processes is vital if condition assessment procedures are to be effectively applied. It is important to identify the critical modes of degradation, the nature and consequences of asset failure, and, if possible, the time remaining until the asset is degraded to the point of failure. Unless there is a reasonable understanding of the degradation and failure processes, it is impossible to establish sensible assessment criteria or to define appropriate end-of-life criteria.

B) Review of Hydro One Distribution's ACA Processes

Existing Hydro One Distribution condition assessment procedures have been identified through review of Hydro One Distribution documentation and interviews with Hydro One Distribution asset specialists. The primary source documents for these reviews was Hydro One Distribution's procedure documents ("HO" documents) that describe the maintenance practices, and specifications for carrying out maintenance work and assessing Asset Condition.
Hydro One Distribution carries out its asset condition assessment using an overall ACA process that describes the overall ACA objectives, prioritization and process to be used for assessing the condition of all its distribution assets. The process is illustrated in Figure 2.1 and is described below.

B1) Overall ACA Process

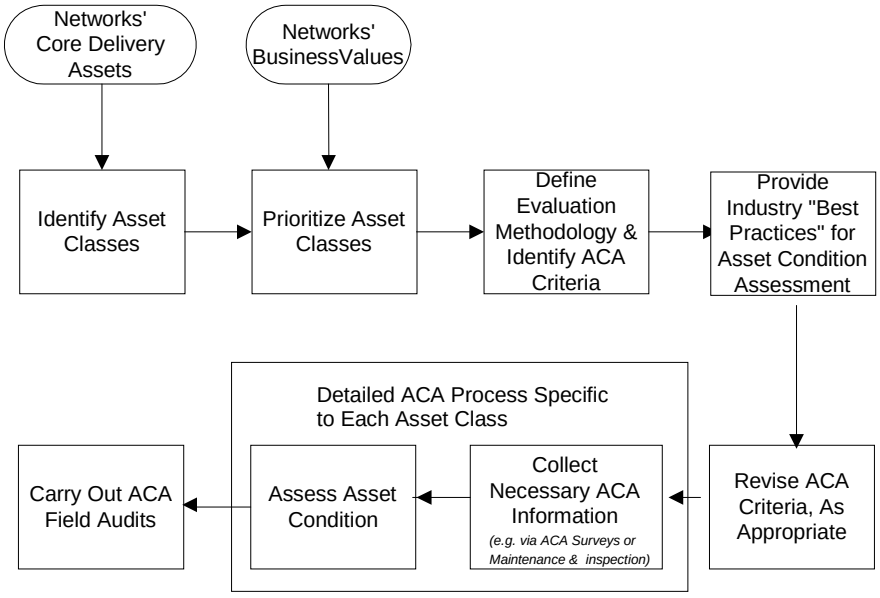

Figure 2.1: Hydro One Distribution Overall ACA Process

Hydro One Distribution's application of condition assessment techniques on the Distribution system assets can only be viewed objectively as part of an overall ACA process as shown in Figure 2.1. The ACA process defines objectives; prioritizes assets for which ACA is to be carried out; identifies the asset degradation and failure modes to determine condition and end-of-life criteria; benchmarks utility practices; assesses asset condition; and verifies that the asset condition assessment results reflect actual field

conditions. Hydro One Distribution's ACA process follows the eight major steps described below.

1. Identify all asset classes and demographics.

2. Prioritize the asset classes (P1, P2, P3) based on the value to the business (Finance, Reliability, Customer, Health & Safety, Regulatory/Legal/Environment), which determines the importance of acquiring condition information.

3. Define the asset information needed to determine/evaluate asset condition against predefined condition indicators, expected results or specifications for all P1 and P2 asset classes.

4. Provide documentation and industry practices / understanding of the asset deterioration process, the failure modes and consequences (including any mean time to failure trends) and define the asset condition and asset end-of-life criteria for all P1 and P2 asset classes.

5. Review the adequacy of existing asset condition documentation (both condition information and decision criteria) on all P1 and P2 asset classes and determine the additional condition information required to adequately assess asset condition.

6. Collect the necessary asset condition information. This information may be obtained from existing databases or through regular testing, surveys or inspections. Define the measurements and coordinate/schedule the necessary work with other Hydro One staff to collect suitable statistically relevant population samples of asset condition information for all major asset categories that will enable an overall population condition assessment.

7. Analyze the asset condition and performance information to identify population condition and performance trends and high risks/impacts of asset condition on meeting business objectives, including service quality standards.

8. Verify and confirm that the asset condition assessment results reflect actual field condition ("spot audits").

2.3.2 Comparison of Hydro One Distribution's Processes With Industry Practices

A benchmarking exercise has been undertaken to compare Hydro One Distribution's practices with those employed by utilities around the world. This benchmarking exercise has been conducted informally, through information known to the Acres project team through prior project involvement and augmented by contacts with utility executives in Canada and the United States.

The practices of the following organizations were included as part of the benchmarking task:

Canadian Utilities

- TransEnergie, Quebec

- Newfoundland Power
- Nova Scotia Power
- NB Power
- Hydro-Quebec
- Manitoba Hydro
- SaskPower
- EPCOR
- Utilicorp
- BC Hydro
- Great Lakes Power Ltd.
- Hydro-Ottawa
- Toronto Hydro
- UtiliCorp Hydro One Distribution Canada (now Aquila)
- Enersource (Mississauga Hydro)
- Acton Hydro
- EPCOR

American Utilities
- ConEdison, New York
- Entergy, New Orleans
- New York Power Authority, Utica NY
- Duke Power, Charlotte, NC
- Seattle City Light
- Puget Sound Energy

UK Utilities
- National Grid Company
- Scottish Power
- Scottish and Southern Energy
- United Utilities
- Northern Electric
- Yorkshire Electricity
- East Midlands Electricity
- GPU
- Western Power Distribution
- 24seven
- Seeboard
- Northern Ireland Electricity

European Utilities
- Stattnett, Norway
- Vattenfal, Sweden
- Fortrum, Finland
- EGE, Czech Rep
- EDF, France
- ESB, Ireland

Australian Utilities

- Orion Energy, NZ
- Mercury Power, NZ
- Integral Energy, Aus
- Energy Australia, Aus
- TransPower, Aus
- TransGrid, Aus
- Powercorr

Acres carried out benchmarking exercises for all of the assets in the study. Not all utilities were contacted in regard to every asset class. Rather, the benchmarking focused on prior project involvement and on business relationships between particular team members and specialists within the various utility organizations. However, each of the organizations listed above served as a point of reference for several classes of assets, and every asset class was benchmarked against at least three organizations within each geographic area.

The benchmarking focused on the types of testing and inspection undertaken for each asset in question, the frequency of testing and inspection, and on the uses made of maintenance and condition assessment data. Particular attention was paid to the extent of development of composite Health Indices for different classes of assets, although most utilities were reluctant to reveal the details of the algorithms used for such Health Indices.

2.3.3 Analysis of Practices for Hydro One Distribution

Building on the insights gleaned from the review of deterioration processes and industry practices, Acres reviewed the practices in use by Hydro One Distribution and other alternative practices. This review, which can be seen in the individual asset sections, included an analysis of available testing techniques, and analysis of improvements, which might be realized by Hydro One Distribution through the adoption of additional or different tests. The review also included an evaluation of suitable condition criteria arising from the tests carried out by Hydro One Distribution.

2.4 Analysis of Asset Condition

2.4.1 Analysis of Specific Condition Indicators – Sampled Assets

The first step in the analytical phase of the study was to evaluate the condition of each asset in respect to the specific condition rating (CR) indicators. This involved screening the available condition data and summarizing the condition results for each condition criterion associated with the Health Index. Valid asset sample results were tabulated for quantities of assets found in the CR1 (i.e. good condition) through CR4 (i.e. poor condition) ratings reported via maintenance activities and ACA surveys. This rating scheme was applied specifically for station assets, for line assets similar methodology was applied to the somewhat different assessment scheme.

In most cases, test and inspection data was available either for the full population of the total asset base or for a statistically significant sample of the total population.

2.4.2 Analysis of Overall Asset Condition – Sampled Assets

The next step was the calculation of a Health Index for each sampled asset, and the assignment of each sampled asset to one of the five health categories of asset condition ("Very Good", "Good", "Fair", "Poor" and "Very Poor"). The results were tabulated for all sampled assets.

2.4.3 Extrapolation of Overall Asset Condition to Entire Asset Base

The final step in the analysis was the extrapolation of the condition results for the sampled condition data to the entire population of similar assets. The extrapolation methods used in this exercise varied from asset to asset, depending upon the bias of the sample. In most cases, the sample was randomly chosen and the condition results were directly extrapolated to the entire population. In other cases, some bias was involved in the selection of the samples, which was accounted for in the extrapolation methodology. But in every case, care was taken to ensure that a statistically relevant sample of asset condition assessments were available prior to extrapolating the results. The methods of extrapolation for each asset class are stated in the detailed asset condition assessment reports.

2.5 Audit of ACA Data Collection Process

The final task in the study was the audit of the ACA data collection process. The objective of the audit was to assess the effectiveness of the ACA process by examining the data collection process (via maintenance activities or ACA surveys), the quality/integrity of data collected from the field and comparing it to localized data repositories and central databases.

Specific elements of the ACA process were reviewed as part of the audit. These included:

a) Form and detail of the request for information to field staff.
b) Collection of information by field staff in a timely manner.
c) Procedures used by field staff, and the accuracy of the data collected.
d) Data entry or concentration for return to Hydro One Distribution.
e) Information available (electronically) to the Asset Managers and Planners within the Hydro One Distribution organization.

Field audits were undertaken in 2003 and the results are presented in Section 4 of this report. Given the short time period (i.e. less than 2 years) since the completion of this audit study, it was determined that a new field audit for the 2005 update was not necessary.

3 Distribution Assets

3.1 P1 Assets

3.1.1 Distribution – Transformers and Under Load Tap Changers

Transformers are static devices that either step-up or step-down voltages. They change AC energy at one voltage-level to AC energy at another voltage-level using magnetic activity. A transformer consists of two or more wire coils wrapped around a common ferromagnetic core. Usually, these coils are not directly connected. The magnetic flux between the coils represents the only connection between them. One of the transformer windings is connected to the AC electric power source (i.e., the primary or input winding). The second winding is connected to the load (i.e., secondary or output winding).

Hydro One Distribution has 1489 transformers and regulators in its distribution substations. These assets operate at various voltages, mainly less than 50 kV. About 9.1% of these are regulating transformers, 61.2% are single- or three-phase transformers without tap changers, and the remaining are three-phase transformers with under-load tap changers (ULTC). As shown in Table 3.1 about 38% of the transformers are over 40 years old.

			Age Group							
	Phase	Voltage Class	0-10yrs	11-20yrs	21-30yrs	31-40yrs	41-50yrs	>50yrs	Total	(%)
Regulators	1	<50 kV	0	0	0	2	3	1	**6**	
	3	<50 kV	5	33	10	47	22	13	**130**	
Sub Total			5	33	10	49	25	14	**136**	9.1%
Transformers	1	<50 kV	0	1	16	48	30	281	**376**	
		>50 kV	0	3	6	54	9	24	**96**	
	3	<50 kV	7	80	66	129	74	77	**433**	
		>50 kV	0	0	0	0	4	3	**7**	
Sub Total			7	84	88	231	117	385	**912**	61.2%
Transformers with ULTC	3	<50 kV	5	79	103	154	12	3	**356**	
		>50 kV	0	36	31	8	5	5	**85**	
Sub Total			5	115	134	162	17	8	**441**	29.6%
Grand Total			**17**	**232**	**232**	**442**	**159**	**407**	**1489**	100.0%
(%)			1.1%	15.6%	15.6%	29.7%	10.7%	27.3%	100.0%	

Table 3.1 - Distribution Station Transformers and Regulators Demographics

Recently, Hydro One Distribution has recognized that the age profile of their distribution transformers raises the potential for increasing failures. Because of this, Hydro One Distribution has developed an enhanced condition assessment program. Utilities worldwide with similar transformer age profiles have made comparable decisions. Due to potential significant end-of-life failures for these assets, it is considered prudent to estimate the remaining life for these transformers before considerable problems occur.

Hydro One Distribution's condition assessment process involves using available information to identify transformers approaching their end-of-life and estimate the

remaining life for other units. The process is a positive step towards a proactive asset management program. It is consistent with current approaches of forward thinking electricity companies.

Hydro One Distribution has used a survey to gather information about many transformer and regulator condition parameters, six of which are considered highly important to the overall condition of these assets. Hydro One Distribution has rated each of these parameters on a scale of 1 to 4. These parameters are also weighted and scored in the Health Index formulation presented in this report. Two of the parameters, Dissolved Gas Analysis (DGA) and the presence of Furans in oil, are considered the most important parameters. Because of their importance in terms of severity on the asset life, if either of these parameters are rated CR4 (i.e., the worst rating possible), the calculated Health Index is divided by 2 to arrive at a final Health Index showing at least poor condition for the unit.

Condition based health indices were developed for about 93% of the total population of distribution station transformers and then extrapolated to the full population. Figure 3.1 shows the extrapolated results.

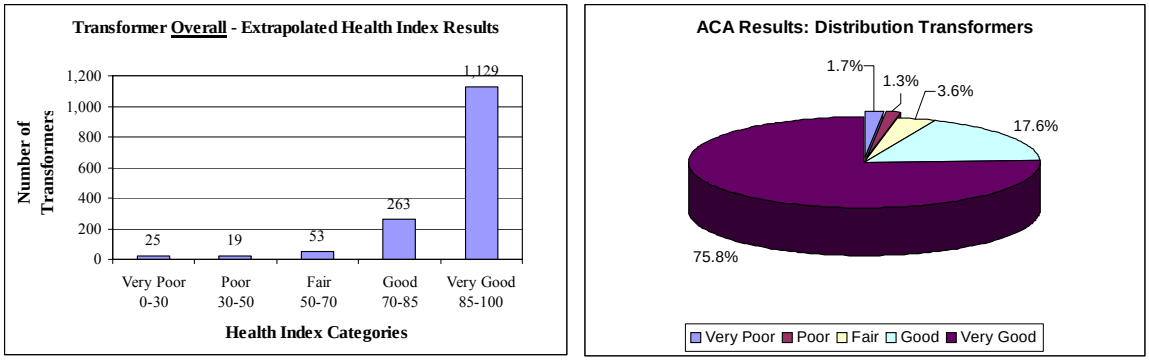

Figure 3.1 - Summary of Extrapolated Condition Assessment Results Distribution - Transformers and Regulators

Based on the above, about 3% of the distribution transformers on the Hydro One Distribution's system are at significant risk of failure and will likely require replacement or refurbishment in the next 5 years. In addition, about 3.6% will likely require increased maintenance/monitoring or specific intervention to ensure that their condition does not deteriorate further over the next 5 years. The remaining 93.4% of the distribution transformers are in "Good" or "Very Good" condition. For those in good and very good condition, it is expected that ongoing maintenance activities will be adequate to maintain that condition during the next 5-year period.

3.1.2 Distribution – Land Assessment and Remediation (LAR) (2003 Assessment)

Hydro One Distribution currently manages 1013 distribution and regulator stations (herein called distribution stations) and a number of other sites that need to be managed from a context of potential site contamination. Historical contamination has occurred within some of the distribution stations, service centres and storage sites as a result of leaks and/or spills from station equipment and from the application of certain long lasting chemicals, such as wood preservatives and herbicides. The primary contaminants of concern include:

- Arsenic (As): from arsenic trioxide, a registered herbicide at the time, used for total vegetation control within Distribution Stations from the 1950s until about 1965,
- Total Petroleum Hydrocarbons (TPH): from leaked and/or spilled transformer mineral insulating oil,
- Polychlorinated Biphenols (PCBs): as a component of transformer oil,
- Pentachlorophenol (PCP): released from treated wood poles.

Hydro One Distribution's distribution station sites are geographically dispersed throughout the Province of Ontario. The station proper typically occupies a fenced area of approximately 1,000 square meters, on a site ranging in size from just over 1,000 square meters to approximately a hectare (10.000 square meters).

Hydro One Distribution has undertaken an aggressive system of management for the environmental conditions at its distribution stations, service centres, and material storage sites. The program is known as Distribution Station Land Assessment and Remediation (DS LAR) and was developed by Hydro One Distribution from practices available in the environmental industry.

The Risk-Based Ranking System developed for the DS LAR program is an electrical industry leading approach that uses practices from across the environmental industry to prioritize sites that represent the highest risks.

There are no known programs to deal with contamination across distribution stations by other utilities. Sites are dealt with on an as-needed basis when a property purchase, sale or lease is undertaken. Hydro One Distribution appears to be well ahead of other power utility companies in its development and application of the DS LAR program to evaluate and manage the environmental condition of the DS sites.

Based on the initial site screening investigations completed at 1,068 sites, approximately 45% of the sites sampled were found to have at least 1 sample, which exceeded the MOE's guideline values for agricultural/residential land-use, for either As, TPH, PCBs, or PCP. These sites were rated as very poor based solely on condition with the understanding that follow-up risk assessment will be needed. As well, since a DS site is not such a land-use, these values were used to assess the severity and impact of contamination, and as inputs for the criticality evaluation.

The risk-based ranking of the sites provides an indication of the health of the sites. For the sites reviewed in the DS LAR program, 377 properties were selected for risk ranking (Tier 1, Tier 2 and Tier 3 with Tier 1 exhibiting the highest risk) by Hydro One Distribution. The remaining sites were considered very low risk because they were built after 1965 (arsenic no longer in use) or had been sampled and shown no significant levels of arsenic, PCBs or TPH. As of the end of 2004, 62 of these sites were rated to be in the Tier 1 and Tier 2 category, which would indicate that for the majority of the DS LAR sites there is a low risk of significant environmental impact. During 2005, it is projected that 7 of these sites will be remediated leaving 55 sites for future years. The current proposed schedule will remediate all 55 sites by 2013.

3.1.3 Distribution – Wood Poles

Wood poles are the most common forms of support for overhead distribution utility feeders and equipment. Low Voltage (LV) feeders make up the 44 kV and 27.6 kV sub transmission system. Hydro One Distribution also owns and operates rural feeders at 8.32/4.8 kV, 12.48/7.2 kV, 25/14.4 kV and 27.6/16 kV.

Hydro One Distribution now manages about 1.6 million wood poles to support the 3,200 feeders in the distribution network. Wood species are predominately Red Pine and Jack Pine (66%), Western Red Cedar (33%) and Douglas Fir (1%).

Table 3.2 shows the age of the distribution pole population as well as the geographic and use profiles. As shown in the Table, over 28% of the total population of distribution wood poles are more than 40 years old.

		Southern Ontario		Northern Ontario			
		Rural	**LV**	**Rural**	**LV**	**Total**	**(%)**
Age Group	**0-10yrs**	145,000	30,000	20,000	10,000	**205,000**	12.8%
	11-20yrs	275,000	30,000	55,000	3,000	**363,000**	22.7%
	21-30yrs	245,000	35,000	45,000	3,000	**328,000**	20.5%
	31-40yrs	180,000	45,000	25,000	5,000	**255,000**	15.9%
	>40yrs	315,000	25,000	100,000	9,000	**449,000**	28.1%
	Total	**1,160,000**	**165,000**	**245,000**	**30,000**	**1,600,000**	100.0%
	(%)	72.5%	10.3%	15.3%	1.9%	100.0%	

Table 3.2 - Age and Geographical Breakdown of Distribution Wood Poles

Based on the process review undertaken by Acres, the testing, inspection practices and decision criteria used by Hydro One Distribution constitute viable and effective processes. Hydro One Distribution's testing and inspection techniques and assessment cycles are consistent with practices around the world. Hydro One Distribution's use of this inspection and test data is in line with practices used by leading-edge utilities in the world.

Hydro One Distribution has used a survey to gather information about several distribution wood pole condition parameters. Measurements of shell thickness and external rot enable Hydro One Distribution to estimate the remaining strength of a pole as a percentage of original design strength. A remaining strength less than 65% (CSA requirement) of the original design strength constitutes the end-of-life for a wood pole in the Hydro One Distribution system. Field crews inspecting overall wood pole conditions also make recommendations based on other factors that may render a pole unsuitable for continued service (e.g., woodpecker damage). These recommendations are factored into the overall Health Index for each pole.

Condition based health indices were developed for about 320,000 distribution wood poles based on surveys conducted by Hydro One Distribution. . An assessment of the condition of the entire population was developed by extrapolating the results for the partial set of

data to the entire population of 1.6 million poles using a linear basis. Figure 3.2 shows the extrapolated results.

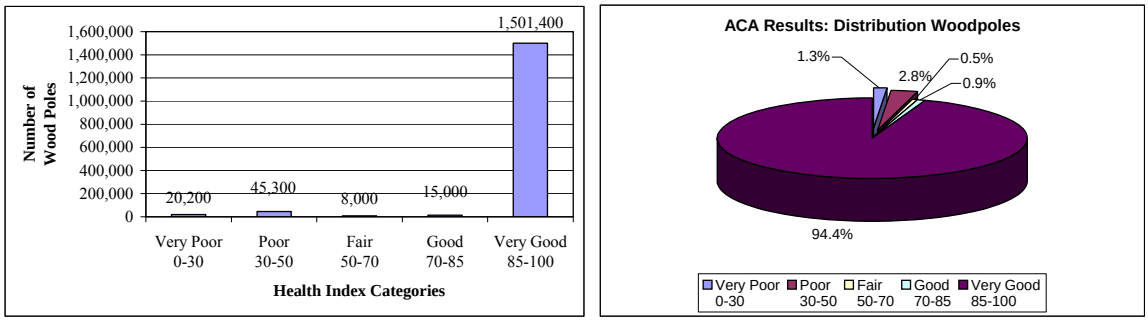

Figure 3.2 - Summary of Extrapolated Condition Assessment Results for Distribution - Wood Poles

Based on the above and considering risk and consequence, about 4.1% (66,000) of Hydro One Distribution's distribution wood poles are at or near end-of-life and should be replaced in a timely manner or over the next inspection cycle. Pole testing programs are normally on about 10-years cycle and the actual poles that need replacement will be identified during that time. About 0.5% (8,000) of the distribution wood poles are in Fair condition and may require increased inspection and remedial action to prevent failure over the next inspection cycle. The remaining 95.4% of the distribution wood poles are expected to remain in "Good" or "Very Good" operating condition during the next inspection cycle.

3.1.4 Distribution – Overhead Line Sections (OHLS)

The distribution overhead feeders asset class is unique from the other asset classes, in that it consists of a group of overhead line component assets (i.e., conductor, insulators and wood poles) that extend anywhere from 1 km to 100 km. Assessing these components as a group is considered the most practical and cost effective method of determining the condition of distribution feeders because end-of-life replacement or refurbishment usually occurs on entire feeder sections rather than on individual components. This approach recognizes that replacement or refurbishment may include some individual components that may not yet have reached their end-of-life.

Hydro One Distribution manages about 3200 feeders.

Determining overall feeder degradation and end-of-life are complex and difficult to define because a feeder comprises multiple overhead line sections with separate components. Each of the components will degrade at a different rate and reach their end-of-life at a different time. The rate of degradation may also vary greatly along a feeder, particularly for wood poles. Detailed degradation and failure modes for individual components are dealt with in programs for specific components (e.g. the wood pole replacement program).

Justifying a major refurbishment or rebuild of a feeder on the basis of end-of-life condition normally requires identifying serious and widespread degradation of its major components (i.e., wood poles, or the conductor). Normally, responses to degradation of individual supports or minor components would occur either through specific replacement programs or as part of ongoing maintenance and restoration processes.

The Health Index formulation presented in this report consists of a composite Health Index for each pole structure. These structure scores are aggregated into a composite structure score for the entire feeder that is then merged with a condition score for the conductor.

Inspections to obtain the information needed for the Health Index involves a foot patrol, basic assessment of poles and visual assessment of supports, conductors and related items. The inspection is limited to poles, cross arms, guys, conductors, insulators and fittings (i.e., the basic functional components of the feeder). It does not include ancillary line equipment.

Hydro One Distribution establishes the condition of the major line components and determines the best course of action for the overhead line section, i.e., refurbishment or replacement. The Health Index can be applied to support the condition-based information as part of the process to decide whether to upgrade or to prioritize opportunities for overall feeder improvements. Having a feeder or section replacement program as part of the overall management of Hydro One Distribution's distribution feeders is necessary and consistent with the rest of the condition-based program to sustain the distribution system.

Condition based health indices were developed for about 15% of the total Distribution Overhead Feeders based upon 2004 pole inspections data. This was not a sufficient sample to extrapolate for the full population of feeders but results for the 15% sample are shown in the main report.

Adoption of the inspection based Health Index to support and focus existing processes provides an objective way to assess asset condition, to ensure effective and consistent decision-making, and to target capital spending.

3.1.5 Distribution – Rights of Way

A Distribution Right-of-Way (Dx-ROW) consists of connected urban and rural land corridors with rights to construct, operate and maintain electric utility distribution lines (i.e., distribution feeders). A Dx-ROW provides the land base for constructing and installing lines at voltage levels of 50 kV and below. These corridors provide a secure means for the safe and reliable distribution of electricity.

Hydro One Distribution Dx-ROW corridors occupy 109,700 hectares in the Province of Ontario. This area spans a length of about 100,600 km, and must be maintained regularly to ensure the safe and reliable supply of electricity to both Hydro One Distribution's customers and other Local Distribution Companies (LDCs). Figure 3.3 shows the land area occupied by Dx-ROW in northern and southern Ontario.

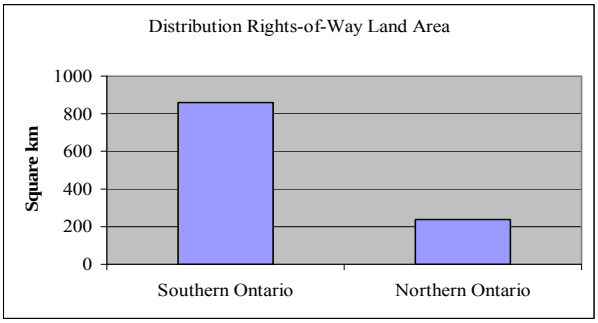

Figure 3.3 - Geographical Breakdown of Distribution Rights-of-Way

Distribution rights-of-way are found in 3 vegetation communities. The predominate community is the temperate hardwood forests which includes areas of the south, east and near north. (includes areas as far north as Wawa & New Liskeard as well as areas in the Northwest around Thunder Bay, Fort Francis, and Dryden) The other two communities include the deciduous forests of Southwestern Ontario (Niagara, Sarnia, and Windsor) and the boreal forests of parts of northern Ontario. (Timmins, Kapuskasing, Geraldton, Chapleau, Pickle Lake, and Red Lake)

Maintenance is based on the growth rates of the vegetation found on the Dx-ROW. Normally, better growing conditions in the south results in more frequent maintenance cycles than in the north.

Small portions of Hydro One Distribution's lines are located on narrower than normal rights of way and therefore requiring more frequent maintenance. Many of these line sections are located within communities. It is estimated that about 10% of the system requires a shorter line clearing and assessment schedule. The sections of a feeder that are on short cycle maintenance are typically reviewed for line clearing and hazard tree assessment on a 3 to 4 year cycle, whereas the assessment on the rest of the system is carried out on a 6 to 8 year cycle.

Staring in late 1990's Hydro One Distribution moved to an asset condition assessment approach, which was then implemented fully in 2001. Since then the Dx-ROW vegetation management program has been based on an assessment of vegetation condition and vegetation caused outages. Also, Hydro One Distribution's program involves tree trimming, hazard tree assessment and removal, and ROW floor vegetation

management that incorporates the use of herbicides, mechanical, manual and biological/ecological controls.

Historically, the rate of vegetation related outages on the Hydro One Distribution overhead lines has been relatively high compared to other jurisdictions with similar terrain and vegetation. Some reasons for this performance include public opposition to tree clearance, budgetary pressures on maintenance expenditures and Dx-ROW maintenance cycles that have been greater than 9 years.

Hydro One Distribution has introduced a Dx-ROW management program based on condition and reliability that also incorporate other factors such as customer complaints, off cycle requests, critical lines, public safety and line maintenance activities. To support this initiative, Hydro One Distribution has introduced an effective condition assessment process that will enable the utility to determine the effectiveness of the current program and target resources where they are most needed.

Hydro One Distribution has gathered information on seven Dx-ROW condition parameters that it considers highly significant to the overall condition of the Dx-ROW and associated feeder(s). Hydro One Distribution also has rated each of these parameters on a scale of 1 to 4 in importance. These parameters are weighted and scored in two separate Health Index formulations for Dx-ROW, one for tree clearance - which relates to reliability optimization and cost consideration, and one for brush control - which relates primarily to cost optimization. The tree clearance Health Index also takes outage performance into consideration to ensure the Health Index for the Dx-ROW reflects both the performance of the feeder and the vegetation condition.

Condition based health indices were developed for about 79% of the total Dx-ROWs that require vegetation management. The results for the tree clearance are shown in Figure 3.4a and for the brush control in Figure 3.4b.

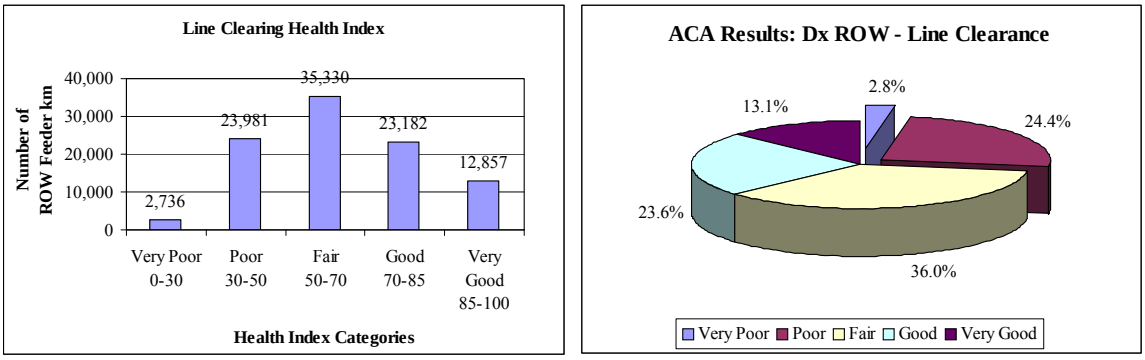

Figure 3.4a - Summary of Extrapolated Condition Assessment Results Distribution Rights-of-Way – Tree Clearance

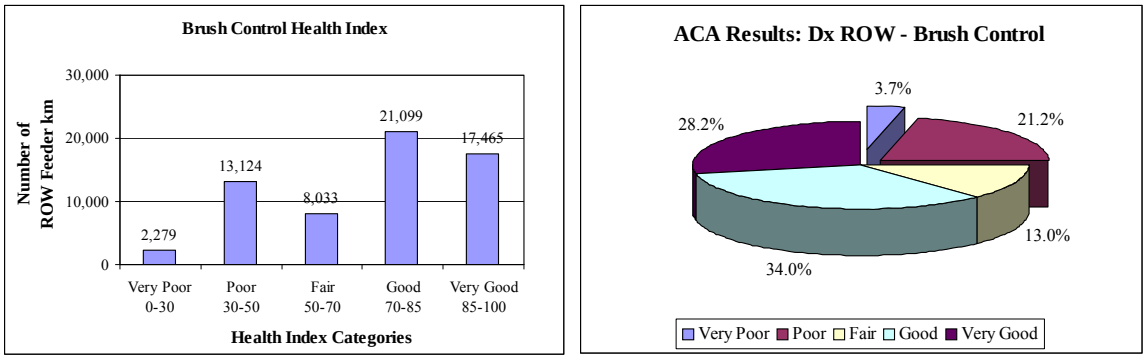

Figure 3.4b - Summary of Extrapolated Condition Assessment Results Distribution Rights-of-Way – Brush Control

Due to the asset group's nature and much shorter life span, the Health Index Scale for Dx-ROW is very different than for most other asset groups and is shown in Table 3.3.

Health Index	Condition	Requirements
85-100	Very Good	Unschedule pending re-assessment in 4 to 5 years or future scheduling based on projection of growth
70-85	Good	Unschedule pending re-assessment in 3 to 4 years or future scheduling based on projection of growth
50-70	Fair	Work may be required within 3-4 years depending on further analysis of ROW
30-50	Poor	Work may be required within two years depending on further analysis of ROW
0-30	Very Poor	Work may be required within one year depending on further analysis of ROW

Table 3.3 - Health Index Scale for Dx-ROW

Based on the above, about 27% of the vegetation managed Dx-ROW on the Hydro One Distribution system may require tree clearance work within the next two years (for brush control this is about 25%). The balance of the Dx-ROW (73%) is not expected to require tree-clearing work before the third or fourth planning year (75% for brush control). The scheduling of these feeders will be adjusted through future planning processes based on updated ACA information, growth projections and feeder tree caused outage data.

3.2 P2 Assets

3.2.1 Distribution – Station Reclosers

Reclosing involves re-energizing overhead and underground circuits shortly after they have been tripped to reduce the length and severity of circuit outages due to temporary overhead circuit faults. In distribution systems a device called an automatic circuit recloser (abbreviated as recloser) often performs the reclosing function. A recloser is a cost-effective light duty breaker that can operate independently to interrupt fault currents.

Reclosers are available in three phase and single-phase design. Single-phase reclosers are used mainly for single-phase loads. They perform trips, reclosures and lockouts on their associated phase. Three single-phase reclosers can also be operated simultaneously via a controller to protect a three-phase load. Three-phase reclosers are used to protect three phase loads. Tripping and reclosing takes place for all three phases simultaneously.

Hydro One Distribution currently manages 5981 distribution station reclosers, consisting of 5823 single-phase and 158 three-phase.

Hydro One Distribution operates an effective recloser maintenance program consistent with normal practice in other leading utilities. Hydro One Distribution currently uses a time based maintenance program (i.e., a 6-year cycle) to maintain and refurbish these devices. After an unrecorded assessment the recloser is either rebuilt to "Very Good" condition or replaced. It is recommended that Hydro One Distribution start recording the assessment as this program could then provide an ideal opportunity to implement a condition assessment process using a Health Index to identify end-of-life, estimate remaining life and establish optimal maintenance cycles.

Using a multi-criteria decision analysis approach, a condition based Health Index was derived for reclosers based on the results of information that could be gathered via regular maintenance activities. The Health Index can be applied on an ad hoc basis to provide condition-based information when considering upgrades or developing priorities for recloser improvement programs. Adoption of an inspection based Health Index can provide an objective assessment tool ensuring effective and consistent decision-making as well as appropriately targeting capital spending.

Hydro One Distribution is replacing or upgrading reclosers with vacuum interrupters. Hydro One Distribution is also considering a program of replacing existing reclosers with SF_6 interrupters. Separate end of life criteria, degradation processes and health indexing will be required for these units since their construction and performance are significantly different than the existing recloser design.

3.2.2 Distribution – Station Circuit Switchers and HV Fuses

Circuit switchers are relatively light duty mechanical switching devices capable of making, carrying and interrupting electrical currents under normal and limited abnormal circuit conditions. A circuit switcher is a combination of a light duty circuit breaker and a disconnect switch, usually the vertical break type. Often, circuit switchers can be substituted for circuit breakers to interrupt abnormal currents and minimize effects on the rest of the system. In general, circuit switchers offer a low cost alternative to the more commonly used circuit breaker and disconnect switch combination.

High voltage (HV) fuses have similar purposes as distribution circuit switchers. Basically HV fuses protect distribution transformers. Hydro One Distribution uses pre-packaged fuse units that consist of:

- The fuse element;
- A boric acid filler that serves as a fault interruption agent; and
- A spun fiberglass tube containment system complete with appropriate end fittings to seal the active components and to allow suitable fuse mounting.

Hydro One Distribution currently manages 37 circuit switchers and 995 HV fuses. As shown in Table 3.4, all but one of the circuit switchers are used at the 115 kV level.

	Voltage Class		
CIRSW	44kV	115kV	Total
Total	1	36	37
(%)	2.7	97.3	100.0

Table 3.4 – Distribution Station Circuit Switcher Demographics

		Voltage Class				
HVFuse		<=28kV	44kV	115kV	Total	(%)
Age Group	0-10yrs	26	93	21	140	14.1
	11-20yrs	99	381	35	515	51.8
	21-30yrs	31	146	28	205	20.6
	31-40yrs	2	3		5	0.5
	>40yrs	1			1	0.1
	Unknown	40	83	6	129	13.0
	Total	199	706	90	995	100.0
	(%)	20.0	71.0	9.0	100.0	

Table 3.5 – Distribution Station HV Fuse Demographics

While fuses can be used at any voltage level, their use becomes increasingly expensive at higher voltage levels. Thus, Hydro One Distribution uses fuses only up to the 115 kV level. As shown in Table 3.5, 71% of Hydro One Distribution's fuses are used at the 44 kV level. In addition, almost all the fuses were installed within the last 30 years, with only 6 units or 0.6% over 30 years old.

Hydro One Distribution's approach to the management of circuit switchers and HV fuses is consistent with practices in other utilities. Hydro One Distribution includes these items in its general routine distribution station inspections. Visual assessment is carried out and, in some cases, infrared surveys also are undertaken. Hydro One Distribution conducts invasive maintenance on circuit switchers as part of a 6-year distribution station maintenance program.

Using a multi-criteria decision analysis approach, a condition based Health Index was derived for Circuit Switchers and HV fuses based on the results of information gathered via regular maintenance activities.

Condition based health indices were developed for 36 of the 37 Circuit Switchers. The results are shown in Figure 3.5.

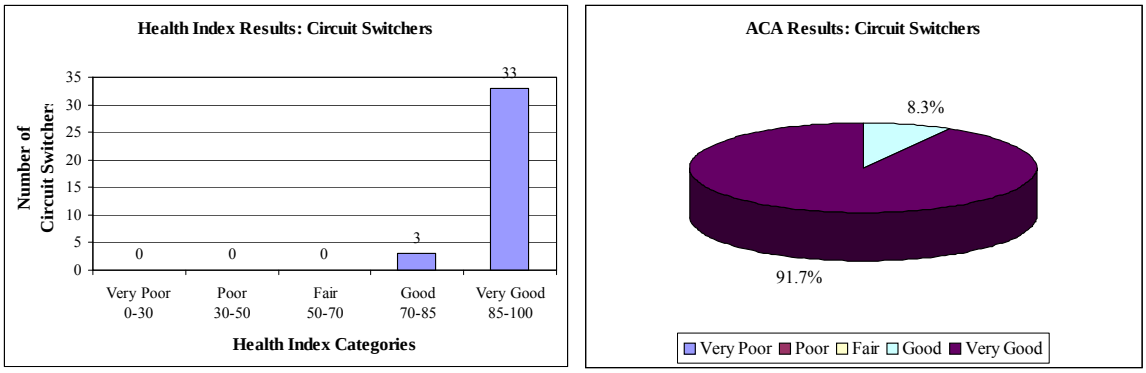

Figure 3.5 - Summary of Condition Assessment Results for Circuit Switchers

Condition based health indices were developed for 988 of the 995 HV fuses (99.2%). The Health Index is based on two condition criteria, outer coating condition and airflow test. Hydro One Distribution only recently began doing airflow tests and had only limited data available for this assessment. Thus, the Health Index relied mostly on outer coating condition information. . It should also be noted that many of the distribution stations recently acquired from local LDC's have obsolete fuse installations that are being replaced by Hydro One Distribution. The criterion used for identifying obsolete fuses is that if the fuse was not manufactured by S&C, it is obsolete and will be replaced as soon as possible. Figure 3.6 shows the results for HV Fuses.

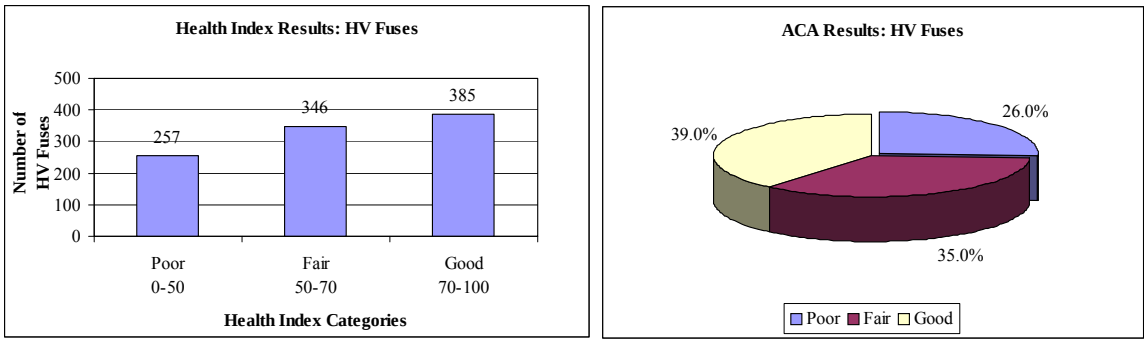

Figure 3.6 - Summary of Condition Assessment Results for HV Fuses

The Health Index results show that about 26.0% of the HV fuses are at high risk of failure, and refurbishment or replacement is likely required within the next five years to prevent failure. About 35.0% of the HV fuses will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further. The remaining 39.0% of the HV fuses are in "Good" or "Very Good" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5-year period.

All Circuit Switchers are in "Good" or "Very Good" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5-year period.

3.2.3 Distribution – Station Sites and Structures

The Distribution Station Sites and Structures asset class includes distribution station fences, structures, insulators, buildings, yards and roads. Security fences around distribution facilities protect the public from hazardous electrical contact and protect the facilities from intrusion and vandalism. At distribution stations, structures made of galvanized steel and wood support buses and equipment. At those structures, insulators are used for the termination of conductors and to support busses or equipment. Hydro One Distribution also owns several types and sizes of buildings in and about distribution stations. Most of these are relay and control buildings used primarily to house protection and metering equipment, batteries, and control and communication systems.

Hydro One Distribution currently manages 1013 distribution and regulating stations and a number of other sites requiring maintenance. These stations and sites have various types of structures and almost all of these sites have fences of differing heights and lengths. Hydro One Distribution has 716 stations (i.e.,) equipped with structures that can readily connect to one of Hydro One Distribution's Mobile Unit Substations (MUS).

	Number of Stations and Sites
Total Stations and Sites	**1049**
Stations and sites with:	
Fences	1032
MUS Structures	716
Support Structures	1033
Buildings	529
Foundation Pads	1042
Access Roads	1039
Drainage	1043
Structure Footings	1026

Table 3.6 – Distribution Stations and Sites; Fences, Structures and Civil

Hydro One Distribution uses a time based distribution station inspection and maintenance system consistent with the Distribution System Code requirements. Maintenance activities include inspecting and repairing assets when defects are noted. Generally, local field staff make these decisions about repairing/replacing defective equipment.

Hydro One Distribution's asset condition assessment (ACA) process, part of its recent distribution station survey provides the basis for a well-calibrated condition-based refurbishment program. Combining the ACA process with ongoing inspection and specific defect repairs provides an effective management program for these assets. This approach for managing sites and structures is also consistent with Hydro One Distribution's wider asset management objectives.

Hydro One Distribution inspection, maintenance and repair program for these assets is typical of the program used by other electric utilities. Other utilities also rely on local

decision making in determining the need for repairs or replacement. Hydro One Distribution's recent distribution stations ACA, however, is not typical of other utilities. It is unusual for utilities to apply a systematic approach to their distribution station infrastructure management. Only few utilities have introduced structured approaches to overall asset management or specific condition assessments for their infrastructure.

The Health Index formulation for sites and structures involved developing multiple criteria representing end-of-life conditions for these assets. Information gathered during regular maintenance activities was used in calculating the Health Index.

Condition based health indices were calculated for all the 1013 distribution stations and number of other sites. About 98.5% of the stations had sufficient data to compute the overall Health Index. The results are shown in Figure 3.7.

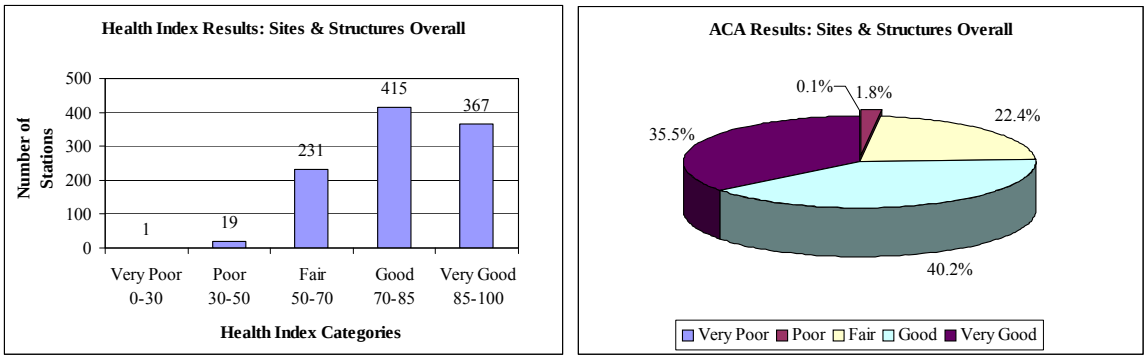

Figure 3.7 - Summary of Condition Assessment Results for Distribution Stations Sites and Structures, Overall

Based on the above, about 0.1% of the distribution station sites and structures are at a very high risk of failure and refurbishment or replacement is required as soon as possible. In addition, about 1.8% of them are at a high risk of failure, and refurbishment or replacement of various components such as fences, buildings and structures will likely be required within the next five years to prevent failure. About 22.4% of the stations and sites will likely require increased maintenance or inspection over the next 5 years to ensure that their condition does not deteriorate further. The remaining 75.7% of these assets are in "Good" or "Very Good" condition, and it is expected that ongoing maintenance activities will be adequate to maintain them in this condition during the next 5-year period.

3.2.4 Distribution – Mobile Unit Substations

Mobile Unit Substations (MUS) are distribution substations mounted on large flatbed trailers suitably equipped and ready for installation. MUSs are deployed at distribution stations to provide continuity of service to customers during construction, maintenance activities, or major component outages. Following a distribution forced outage or distribution system equipment failure, an MUS is deployed to minimize customer outage times until repairs are completed.

Currently, Hydro One Distribution manages 28 MUSs of varying age groups as is shown in Table 3.7.

Age Group	Number of MUS Trailer	%
0 – 10 yrs	7	24
10 – 20 yrs	8	29
20 – 30 yrs	3	11
30 - 40 yrs	10	36
> 50 yrs	0	0
Total	**28**	**100**

Table 3.7 – Distribution MUS Trailer Demographics

Due to the nature of MUS use, Hydro One Distribution recognizes that their reliability is critical. Therefore, MUS electrical equipment (i.e., transformers, switchgear and ancillary equipment) is fully inspected and undergoes maintenance between each use. Basically, MUS maintenance and inspection programs are the same as those applied to static equipment in distribution substations. However, MUS inspection and maintenance procedures are done much more frequently. Also, Hydro One Distribution immediately addresses any deterioration detected that could compromise substation performance during its next use. Consequently, MUS switchgear, tap changers and ancillary equipment are maintained at a very high standard.

A multi-criteria decision analysis approach was used to derive a condition based Health Index for MUS. It is based on results of information gathered via regular maintenance activities. The overall MUS Health Index combines individual Health Indices for MUS switchgear, transformers and trailers. In this case, however, there was insufficient condition information to compute a Health Index for switchgear and transformers. It is recommended that this information will be collected and recorded for future analyses.

Condition based health indices also were developed for all 28 MUS Trailers. Figure 3.8 shows the results.

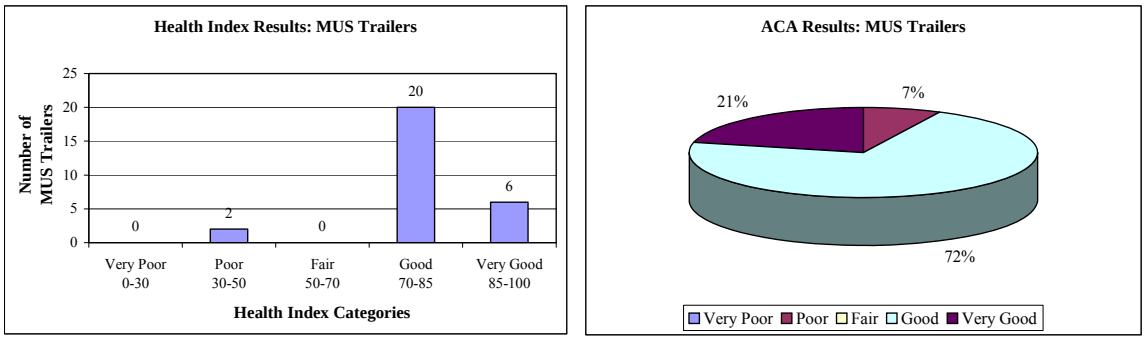

Figure 3.8 - Summary of Extrapolated Condition Assessment Results for MUS Trailers

Based on the above, only two (i.e., 7%) of the MUS Trailers are in poor condition and at medium risk of failure. For these, to prevent failures, increased monitoring, assessment and maintenance will be needed plus plans for refurbishment or replacement will be required in the next five years. The remaining 93% of the MUS are in "Good" or "Very Good" condition. It is expected that ongoing maintenance activities will prove adequate to maintain them in this condition during the next 5-year period.

3.2.5 Distribution – Submarine Cables

Distribution System Submarine Cables consist of submarine cables, potheads, terminators and shore terminations at both ends of each cable. This kind of cable is used mainly in "cottage country" where lakes and water crossings are common. It is impossible to build overhead lines in these areas due to the distance between points of landfall across water bodies. Distribution system submarine cable installations have a high initial capital cost. They also are very costly to maintain and repair because the cables are laid on the bottom of the waterways that they cross.

Hydro One Distribution currently manages a system of distribution submarine cables with a total circuit length of about 2200 km operating at voltages less than 28 kV.

About 80% of the distribution system submarine cables are configured in a single-phase radial system. To provide electricity to larger islands, a three-phase supply is used. These consist of four single cables with one cable serving as an emergency standby.

Prior to the 1970's, typical installations were Paper Insulated Lead Covered (PILC) submarine cables. Since the 1970's, Extruded Cross-Linked Polyethylene (XLPE) distribution submarine cables have been used. About 80% of Hydro One Distribution's submarine cables are XLPE.

Hydro One Distribution bases its management practices for submarine and underground cables on performance, i.e. two failures within a section of cable will normally lead to decision to replace the cable. In recent years, decisions on submarine cable replacement have been supported with inspection and corrosion assessment of the neutral at the point of entry into the water. Neutral corrosion has been identified as a potential safety issue. Thus, the degree of neutral corrosion at the waterline will determine the need to repair or replace the cable. The decision whether to repair or replace is made on the basis of visual assessment and performance of the cable.. Hydro One Distribution's submarine cable management program is consistent with traditional approaches adopted by many other utilities for these assets.

Hydro One Distribution does not currently collect sufficient condition information on submarine cables to calculate a condition based Health Index. However, if the results of the neutral inspections and relevant cable characteristics and performance information could be collated in a consistent fashion, it might be possible to identify the high risk cables that are at the end of their useful service life.

3.2.6 Distribution – Underground Cables

Distribution System Underground Cables consist of underground cables, splices/joints, elbows, potheads and terminators at 44 kV voltage levels and lower. This asset class includes sections of underground cable running from distribution stations to overhead lines and from overhead lines to customer service connections and switches. However, it does not include cables contained entirely within stations. Distribution underground cables are used mainly in urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The configuration of the underground cable system is mainly radial.

Hydro One Distribution currently manages a system of distribution underground cables with a total circuit length of about 4200 km operating at voltages of 44 kV and lower.

Hydro One Distribution's underground cables consist of about 80% Extruded Cross-Linked Polyethylene (XLPE) 20% Paper Insulated Lead Covered (PILC) and a very small percentage of Ethylene Propylene Rubber (EPR). Over 80% of the cable conductor is stranded aluminum and the rest is stranded copper. About 85% of the distribution underground cables are direct buried except when crossing roads and railways.

Several factors can affect cable performance. These include the soil surrounding underground cables, proximity to heat sources and other underground services. These factors can critically affect the reliability, performance and deterioration of underground cables.

Consistent with OEB regulations, maintenance activities for distribution underground cables involve a 3-year inspection for urban circuits and a 6-year inspection for rural circuits. Inspections involve visual examination of the components associated with cable terminations, potheads, elbows and cable riser poles. For most cables that are buried directly underground, no examination of cable or splices is done. For a few cables that are in ducts, some examination of their external condition may occur for troublesome or critical circuits.

Hydro One Distribution does not currently collect sufficient condition information on underground cables to calculate a condition based Health Index. As a result, Hydro One Distribution has limited condition information on underground cables. This is consistent with industry practices for managing a small system of distribution underground cables. However, if the results of Hydro One Distribution's cable inspections and relevant cable characteristics and performance information could be collated in a consistent fashion, it might be possible to identify the high-risk cables that are at the end of their useful service life.

Hydro One Distribution has a relatively new and predominantly XLPE underground cable network. Therefore, it is unlikely that these new cables are approaching any near-term widespread end-of-life issues that will result in increasing failure rates.

P3 Assets

3.3.1 Distribution – Circuit Breakers

The circuit breaker asset class includes several types of mechanical switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Distribution system circuit breakers are used sparingly on the Hydro One Distribution system. They typically serve feeders with single loads, and multiple single and three-phase transformers.

Hydro One Distribution follows a process that is very similar to other major utilities around the world with respect to circuit breaker inspection and diagnostic testing as part of its overall preventative maintenance program. Its process contains all the necessary elements for managing a small fleet of circuit breakers that is similar to other leading electricity companies: existing practices and programs include the same range of tests applied at approximately the same frequency. Hydro One Distribution includes circuit breakers in its general routine distribution station inspections. Visual assessment is carried out and, in some cases, infrared surveys also are undertaken. Hydro One Distribution conducts invasive maintenance on circuit breakers as part of a 6-year distribution station maintenance program. Refurbishment and replacement decisions are made based on observed condition during maintenance inspections.

3.3.2 Distribution – Spares

At Hydro One Distribution, spares are held for the maintenance/replacement of distribution fixed assets and planned projects. It primarily includes transformers, poles, switches, protective devices, metering systems, and component replacement parts for the distribution system. A key driver in establishing the spares inventory is the need to restore power in a timely manner. Other factors in the establishment of spares and inventory levels are the vendor lead-time, demand levels and the forecasted work program. Emergency stock is located at a number of sites around the province, primarily in work centres.

Distribution level spares' management varies considerably between utilities. In theory, most utilities maintain a unified list of strategic spares (e.g., complete equipment and component parts) and keep them in defined storage conditions. For used equipment, utilities normally define its condition at the time of removal from the system. Usually, assessment is limited to recording the operational history and results of previous maintenance based tests (e.g. oil test results of transformers). In many cases, the only assessments carried out during storage are periodic checks of storage conditions. It is rare to have specific, defined maintenance programs for spares. In most cases re-assessment of condition is only undertaken prior to re-use. Although, this seems to be the normal process for utilities it is not considered adequate for reliable spare management on certain types of assets such as power transformers. It should be noted that Hydro One Distribution's process was not studied in this regard.

In practice, the situation is less well organized. Often records for spares are incomplete, with different regions or departments within a company maintaining separate spares

policies and programs. Also, storage conditions and assessments can be totally different, even within the same company.

For many types of older distribution switchgear, obtaining component parts has become increasingly difficult. Often the original manufacturer no longer exists or does not support the old equipment. In such cases utilities have sought alternative sources for components. While this has been successful in many cases, it also has raised some problems related to specification and quality of components. A number of failures have been attributed to the use of inappropriate or sub-standard components.

The degradation processes for spare transformers and switchgear stored outdoors are similar in many ways to those that are still operational, and maintenance and inspection should be performed at similar levels. The rate and severity of degradation is dependent on a number of inter-related factors, particularly the environment in which the equipment is stored. For items not in use, and therefore not subject to electrical, operational or load related degradation, moisture ingress and other moisture and environmental effects such as corrosion are the most significant.

3.3.3 Distribution – AC/DC Service Equipment (Including Batteries and Battery Chargers)

AC/DC service equipment such as batteries and chargers help ensure the availability of stand-by power for critical equipment. Batteries, for example, supply power for control, operation, monitoring and annunciation, including protection and control devices, switchgear, circuit breakers, and transformers. Generally, batteries consist of banks of cells that when connected in series provide required voltage levels for the battery bank.

Historically, factors used to assess the end of a battery's life have included age, appearance, and the history of specific gravity and cell voltage measurements. Now, battery load tests provide the best indication of a battery's condition. Typically, load tests are used to identify and confirm the condition of batteries that appear deficient based on previous inspections or evaluations.

Regular inspections and operating tests help track the health and condition of AC/DC service equipment such as batteries and chargers. Routine maintenance activities help to detect and rectify deficiencies before they cause permanent battery damage. Reviewing trends in maintenance records also can provide early warnings of potential failures.

Hydro One Distribution's AC/DC service equipment is managed during routine distribution station inspections. The frequency of such inspections varies from once every three months to once every year. During inspections, the AC/DC service equipment receives visual evaluation and functionally testing. Inspectors note any deficiencies and report them as defects, which are categorized as either urgent or non-urgent. This initiates repairs or other corrective actions as appropriate. Occasionally, if widespread or frequent problems appear, an assessment may be undertaken to determine need for complete replacement/refurbishment.

3.3.4 Distribution – Switch and Fuse Feeder Protection

Hydro One Distribution uses a combination of reclosers and fuses to provide the necessary feeder protection – relays are rarely used.

Fuses may be applied to a distribution feeder at the substation or downstream of the substation. Hydro One Distribution may use fuses or reclosers at the substation for overall protection of the feeder. Hydro One Distribution also uses line reclosers and fuses to provide feeder section isolation by coordinating the characteristics of the fuses and recloser settings and the number of reclosures programmed into each recloser. Reclosers allow a faster return to service automatically under many conditions and thereby improve the reliability of the service to distribution customers.

3.3.5 Distribution – Oil Containment

Oil containment systems capture spills from various pieces of distribution equipment. Generally, these systems consist of concrete vaults large enough to contain any potential spills from a particular piece of equipment. Also, such systems must be decoupled from normal drainage systems.

Over the last 20 years, heightened awareness of environmental issues plus additional regulations and higher penalties have led electric utilities to develop more systematic and consistent approaches to spill containment. Before this, oil containment represented a possible design feature for large transformer installations. However, the use of containment systems was inconsistent and non-uniform. Electric utilities now ensure that equipment containing oil over certain volumes has properly designed spill containment systems. In addition, local environmental authorities may audit these systems for compliance with applicable regulations.

Spill containment systems are made primarily from concrete. These facilities may degrade from cracking, corrosion, and shifting overtime. Generally, maintenance and ongoing management of oil containment systems is limited to visual assessment during routine distribution station inspection. Functional checks are performed on pumps used to remove rainwater.

As part of a recent program to ensure that oil containment systems conform to certain standards, the overall condition of these systems was assessed. This condition assessment process resulted in upgrades and replacements as needed. Since most systems were subject to that relatively recent assessment, significant end-of-life conditions typically should not be found. However, full assessment and any needed refurbishments occur when major defects or damage are detected during routine inspections.

3.3.6 Distribution – PCBs and Hazardous Waste

Polychlorinated biphenyls, commonly known as chlorobiphenyls or PCBs, are mixtures of synthetic organic chemicals first synthesized and commercialized in North America in 1929. Due to their non-flammability, chemical stability, high boiling point and electrical insulating properties, PCBs were used in hundreds of industrial and commercial applications including electrical, heat transfer, and hydraulic equipment; as plasticizers in

paints, plastics and rubber products; in pigments, dyes and carbonless copy paper and many other applications.

PCBs are very persistent both in the environment and in living tissue. Because of potential adverse effects of PCBs, the Canadian government has taken several steps to eliminate PCBs from Canada. In 1977, Canada banned the import, manufacture, and sale (for re-use) of PCBs. In 1985, Canada also prohibited releases of PCBs to the environment. Canada regulated PCB storage in 1988. PCB handling, transport and destruction are also regulated, primarily through provincial government regulations.

Canada has allowed owners of PCB equipment to continue using PCB equipment until the end of its service life. Canada also has compiled and maintains and inventory of PCBs, and now monitors changes in status from PCBs in-use to storage or destruction. Recently Canada proposed revisions to the existing Chlorobiphenyl Regulations of the Canadian Environmental Protection Act (CEPA) that would set specific dates for the complete destruction of PCBs in service and storage for certain equipment types. These regulations have not yet been adopted but many utilities have begun to phase-out PCB equipment and dispose of PCBs in approved waste disposal facilities.

At Hydro One Distribution, equipment such as circuit breakers and switchgear have frequent oil changes. If testing reveals PCB contamination, the used oil is treated in conformance with regulatory requirements. Hydro One Distribution has conducted widespread sampling of oil in ground-mounted transformers and confirmed that PCB contamination is generally below regulatory limits. Transformers containing higher levels of PCBs have been appropriately labelled and registered with applicable government agencies. Pole-mount transformers are outside the scope of the proposed changes to the environmental regulations as there is no requirement to test for PCB's.

Hydro One Distribution routinely tests equipment before decommissioning. In addition, soil testing is done when specific concerns arise (e.g., after a spill) or when the utility plans to re-use land for different applications.

3.3.7 Distribution – Line Switches

Disconnect switches isolate equipment or line sections of the distribution system for maintenance, safety, and other operating requirements. Unless specifically designed to operate under load conditions, these switches operate only when the current through the switch is zero. Most distribution line switches are 600 A.

Generally, distribution utilities do not have replacement programs for these switches, and they are considered "run-to-failure" items. However, some utilities have had to replace in-line switches due to misalignment problems. Several utilities perform maintenance on a cyclic basis (e.g., every 5 years), but in most cases this is done on an as-needed basis. Maintenance involves cleaning, lubricating and adjusting switch contact alignments. Generally, no testing or electrical measurements are done.

3.3.8 Distribution – Line Reclosers

Reclosers are cost-effective light duty breakers able to operate independently to switch fault currents. They are equipped with fault sensing devices and control programs that cause them to trip and reclose up to four times before final lock out. Reclosers are designed for operation up to a maximum of 36 kV, and are only used on distribution circuits. Reclosers are equipped with interrupters in which the breaking and making of fault currents takes place. The interrupters use oil or vacuum as their insulating and interrupting agent. Two types of controllers are used in reclosers: hydraulic (used in older models) and electronic (used in newer models).

Increasingly, utilities are replacing traditional oil-filled devices with more modern vacuum and SF6 pole mounted switchgear. The more modern equipment requires less maintenance than the traditional oil-filled equipment. Utilities generally manage their remaining oil-filled equipment through regular time interval or number of operations based maintenance. The maintenance time cycle can range from 6 months to 8 years, depending on the type and number of operations. Often travelling spares or refurbished recovered units are used as replacements during recloser maintenance.

External corrosion represents the most significant degradation process for this equipment. At the end of their useful service life, these devices are generally replaced with modern SF_6 and vacuum equipment.

3.3.9 Distribution – Line Transformers (Pole and Pad)

Most utilities typically operate pole-mounted transformers as run-to-failure items. Because of this, utilities seldom make any attempt to gather information about the duties or condition of these assets.

Line transformers generally receive basic visual inspections during line patrols. Replacements would occur if very severe degradation (e.g., corrosion or oil leaks) or damage was observed, or if the equipment was obsolete or overloaded.

In the few cases when utilities do perform specific inspections on line transformers, they typically occur on a 5 to 6-year cycle. During such inspections, infrared and ultrasound evaluation is performed along with standard checks for leakage, oil levels, connections and general condition of the unit (corrosion and seals, etc).

4 Audit of ACA Data Collection Process

This audit was intended to confirm that the process established by Hydro One Distribution to obtain condition information from service staff for the Priority 1 (P1) and Priority 2 (P2) asset classes met the following criteria:

1) has been clearly defined by Hydro One Distribution
2) has been properly contracted for by Hydro One Distribution
3) has been clearly communicated to service staff
4) has been properly and accurately collected by service staff
5) has been properly and accurately recorded on site by service staff in accordance with the defined schedule
6) was properly and accurately recorded electronically by service staff in a timely fashion after site work was completed
7) is readily available to Hydro One Distribution staff for the purpose of analyzing asset condition

The data collection process was audited, complete with demonstrations of its execution, with the help of sample data. Weaknesses or deficiencies that may affect the integrity of accumulated condition related data and information were identified.

The following discussion of audit results is presented according to the grouping discussed previously: lines and ROW assets, and station assets.

4.1 Audit of Lines and ROW (From 2003 report)

Field audits were undertaken in 2003 for most of the P1 and P2 assets, to ascertain the degree of conformance of data collection activities to defined procedures and practices, and the degree of conformance of observed conditions to recorded field data and stored data.

In general, the auditors found that data was being collected by field groups in accordance with specifications, and that there was good correlation between field observations and recorded data. Such minor discrepancies as were observed followed no discernible pattern, and it has been concluded that no bias has been introduced in the overall condition results as a result of these minor discrepancies. Given the relatively short time period (i.e. less than 2 years) since the completion of this 2003 audit study, it was determined that a new field audit for the 2005 update was not necessary.

Appendix 1

Development of Asset Condition Composite Health Indices

An asset condition composite Health Index is a very useful tool for representing the overall health of a complex asset. Distribution assets are seldom characterized by a single subsystem with a single mode of degradation and failure. Rather, most assets are made up of multiple subsystems, and each subsystem is characterized by multiple modes of degradation and failure. Depending on the nature of the asset, there may be one dominant mode of failure, or there may be several independent failure modes. In some cases, an asset may be considered to have reached "end-of-life" (EOL) only when several subsystems have reached a state of deterioration that precludes continued service. The composite Health Index combines all of these factors using a multi-criteria assessment approach into a single indicator of the health/condition of the asset.

Individual condition indicators provide a basis for assessing specific condition information about an asset, and these indicators may reflect specific asset defects or the extent of one particular mode of asset deterioration. Hydro One Distribution uses condition indicators extensively, normally for station assets in the form of condition ratings ranging from CR1 through CR4 or CR5. A condition rating of CR1 generally represents "like-new" condition for a particular indicator, whereas the highest condition rating (CR4 or CR5) generally represents an EOL condition for a particular indicator, or a need for urgent attention.

For a typical asset class, a wide range of diagnostic tests and visual inspections are undertaken as part of the maintenance program or special-purpose Asset Condition Assessment (ACA) surveys. In some cases, a high condition rating (CR4 or CR5) value will represent a failure of a subsystem, which can be repaired through replacement of that subsystem, with no resultant impact on the serviceability of the overall asset. However, it should be recognized that generalized deterioration of many or all of the subsystems that make up an asset could also be a valid indication of the overall health of the asset. A composite Health Index captures generalized deterioration of asset sub-systems, as well as fatal deterioration of a dominant subsystem.

In developing a composite Health Indices for assets, it is very important to understand the functionality of the asset, and the manner in which the various subsystems work together to perform the main functions of the asset. With a clear understanding of asset functionality, the various condition ratings can be combined to create a composite "score" for the asset, and the continuum of asset scores can be subdivided into ranges of scores that represent differing degrees of asset health.

The critical objectives in the formulation of a composite Health Index are as follows:

- *Indicative:* the Index must provide a meaningful indication of the suitability of the asset for continued service or representative of the overall asset health

- *Objective:* the Index should, wherever possible, rely on objectively verifiable measures of asset condition as recognized in the industry, as opposed to subjective observations and/or condition risk factors. Probability of failure for certain condition levels is then based on engineering judgment and industry experience.

- *Simple:* the Index should be understandable and readily interpreted.

The critical process steps used to develop the condition based Health Indices are described below.

1) Determine Condition Factor Importance

Development of a condition Health Index requires an assessment of the relative degree of importance of the different condition factors in determining the health of the asset. Each condition factor must be assessed as falling into one of the categories shown in Table A1.1.

No impact	Indicator reflects defects or deterioration measures that have no impact on overall asset health
Contributing Factor	Indicator reflects defects or deterioration measures that range from low to high in importance, but typically in combination with other measures as part of a formulation of generalized deterioration
Combinatorial Factor	Indicator reflects a measure which does not represent asset condition in isolation, but is a critical component in a complex logical and/or mathematical formulation of asset health
Risk Factor	Indicator reflects risk factors known to presage poor health, but does not represent a direct measure of health
Dominant Factor	Indicator reflects the health of dominant subsystem that makes up the asset, and EOL based on this single factor represents EOL for the entire asset

Table A1.1 - Condition Factor Relative Degree of Importance

Through this screening process, many condition parameters may be eliminated from consideration as part of the asset Health Index.

2) Formulate the Condition Based Health Index

Using a multi-criteria analysis approach, combine the various factors into an idealized condition based Health Index. This involves grouping together the various factors, crafting the mathematical and/or logical formulations, and establishing the importance weightings of all the factors to allow combining them into a single Health Index or score.

3) Develop a Uniform Scoring System

Develop a quantified scoring system to appropriately represent the asset health consistent with the philosophical approach developed in step 2. In general, a uniform scoring system has been adopted through the following steps:

i) Convert the CR1-CR2-CR3-CR4 "deterioration" scores to health scores in the range 3-2-1-0 (3 =perfect health, 0=end-of-life), similar ratings for line assets are also converted in the same manner.

ii) Assign an importance weighting to each factor (1=modest importance, 2=intermediate importance, 3=high importance),

iii) Formulate a general deterioration index by calculating the maximum possible score by summing the multiples of the importance weighting and the maximum possible health score for each factor,

iv) Calculate the maximum possible score for data sets of individual assets. If this is less than 70% of score in iii), the particular asset is deemed to have insufficient data for calculating a valid Health Index.

v) For records with sufficient data, calculate actual score for the asset.

vi) Normalize the Health Index based on the maximum possible score (iv), so that a result of 100% is excellent health and 0% is very poor health.

vii) Apply any dominant factors as described in the Health Index formulation, e.g. divide by 2.

4) Establish Minimum Criteria Requirements

Establish a minimum quota of tests/observations needed for calculating a valid asset Health Index because it is not reasonable to expect that information will be available on every test criterion. In general, this minimum level is set to 70% of the maximum available score; in other words, test information must be available on criteria that make up 70% of the total maximum index.

Actual asset condition data is then analyzed to ascertain the extent to which valid scores may be calculated using the adopted Health Index. This "sanity check" is used to validate the recommended Health Index formulation and adjustments are made, as appropriate, to ensure the results reflect actual asset condition..

5) Establish Asset health Categories

Correlate the continuum of asset health scores into discrete categories of asset health. In general, five categories were deemed appropriate for the purpose of helping Hydro One Distribution programming investment and maintenance activities as shown in the table A1.2.

Condition	Description	Remaining Life (where supported)	Requirements
Very Good	Some aging or deterioration of a limited number of components	>15yrs	Normal inspection and maintenance
Good	Deterioration of some components	10-15yrs	Normal inspection and maintenance
Fair	Noticeable deteriorationor serious deterioration of specific components	5-10yrs	Increase diagnostic testing, possible replacement needed before 5 years depending on criticality
Poor	Widespread serious deterioration or significant deterioration of a dominant component	1-5yrs	Start planning process to replace, considering risk and consequences of failure
Very Poor	Extensive serious deterioration or serious deterioration of a dominant component	0–1 yr	At end-of-life, immediately assess risk; replace based on assessment

Table A1.2 – Categories of Asset Health

Converting the continuum of Health Indices into five discrete categories for a condition index requires fine-tuning of the health scoring system, since it is necessary that the relative degree of severity of the scores due to "dominant" factors and those due to generalized degradation match up at the boundaries between each category. This may require iteration of steps three and four to ensure that the resulting Health Index is rational and reasonably reflects field condition.

Industry Best Practice Review for Hydro One

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Submitted By:

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INTRODUCTION

This report summarizes an EPRI Solutions' review of Industry Best Practices of Transmission Asset Condition Assessment (ACA) approaches used by leading utilities.

For each equipment group the review focuses on the advances in industry best practice, technologies and processes that have occurred in the last few years.

The information used in this report came from EPRI project literature, utility and commission websites and EPRI Solutions maintenance experience at the following list of utility companies in North America and internationally:

- Arizona Public Service
- Bonneville Power Administration
- Center Point Energy
- EDELCA – Venezuela
- Hawaiian Electric Company
- ICE – Costa Rica
- Long Island Power Authority
- Los Angeles Department of Water and Power
- National Grid Group
- Nebraska Public Power
- New York Power Authority
- Northeast Utilities
- Omaha Public Power
- Sacramento Municipal Utility District

PRIORITY 1 ASSETS

1. Transformers (Auto and Step-Down Transformers)

In the past few years, a number of transformers and transmission shunt reactors have failed abruptly without any external disturbances or alarms. Some of these failures were attributed to corrosive sulfur contamination of the insulating oil and other materials. A number of utilities in North and South America are screening their transformer populations for corrosive sulfur contamination. The recent failures have also triggered a review of the present testing specifications and the development of new testing methods for determining corrosive sulfur contamination in insulating oil.

Historically, utilities have used several different programs and types of calculations to produce normal load ratings and loadings beyond nameplate for the mix of their transformer fleet. Recognizing that these methodologies have changed over the years, leading utilities are re-evaluating their transformer loading performance. The present approach is an integration of current diagnostic testing and historic test data with an expert software system. The output is providing new transformer ratings according to loading analysis, confirming the maximum sustainable load for short-duration excursions, and determining the up-rating capability for each transformer based on the potential overhaul and/or upgrades that can be performed. The output also ranks selected transformers in terms of failure risk.

2. Gas Insulated Switchgear (GIS) Equipment

For the majority of utilities, GIS substations have or continue to exhibit some SF6 leakage. The level of leakage is dependent to some extent on quality control during erection, but problems have been found to occur after some years of service. The approach across utilities is to address this problem on a site-by-site basis, adjusting or replacing joints as necessary.

Many utilities practice precautionary switching in response to a low SF6 gas pressure alarms. Some utilities are evaluating the use of a rate of change of pressure alarm to manage their responses to gas alarms better.

The performance of grading capacitors on GIS circuit breakers in the energized open position has created a low confidence level. One practice is to open the adjacent disconnect switch, shortly after the breaker is open, to relieve the stress on capacitors.

Poor installation and assemble of GIS components, leading to early infant mortality of equipment is still an issue for US utilities. Where incidents have occurred, such as internal flashovers, the response by utilities is typically a modification of maintenance practices, a review of cleaning materials used and the installation of partial discharge monitoring equipment.

3. Oil Circuit Breakers

Recently, more utilities are exploring oil circuit breaker (OCB) oil analysis as a diagnostic tool. The process is neither overly complex nor does it require an outage. The package of tests includes:

- Dissolved Gas Analysis (DGA)
- Particle count and size
- Particle typing
- Oil quality
- Total metals

There are several **oil analysis approaches** taken by utilities:

- First, there are those utilities that have decided not to adopt oil analysis as a diagnostic tool because they are implementing an OCB replacement program over the next 5–10 years. They have undertaken risk assessment of future maintenance requirements for the remaining population and continue to implement any remaining internal inspection on a time-base approach.
- The second group includes those utilities that periodically test for moisture and acidity—typically every 4 years—and continue with contact assembly inspections on a periodic basis every 4–10 years and/or use triggers such as number of operations, number of fault interruptions, and I^2T (fault power monitoring).
- The third group continues with periodic contact assembly inspections on a periodic basis every 4–10 years and/or uses triggers such as number of operations, number of fault interruptions, and I^2T. These utilities have also just started oil analysis programs on a pilot basis on specific classes of OCBs.
- The fourth group has added oil analysis as a trigger for internal maintenance on specific classes of OCBs (e.g. 230kV) and continues with periodic maintenance and other triggers on the remaining population.
- The fifth group has abolished periodic internal inspections and proactively reviews all diagnostic data from oil analysis, infrared inspection, interrupter resistance measurement, mechanism motion analysis, and the number of operations/fault interruptions to determine when maintenance is next due.

Although oil analysis helps extend contact assembly inspections, many OCB failures have been traced to faulty lubricants and/or questionable lubrication practices. Regular mechanism maintenance is undertaken by most utilities every 2–6 years. This consists of lubrication, overall phase-resistance tests, and motion analysis. Some utilities have re-lubricated specific circuit breaker mechanisms with longer-life fluorosilicone grease and dry-film bonded lubricants, in part to extend their mechanism maintenance cycle. Exercising OCBs is also scheduled at least once a year.

4. Air Blast Circuit Breakers

A review of industry practices shows that utility practices and the manufacturers' recommendation are to recondition the pressurized head beakers every 15–25 years, depending on breaker type and its operating environment. In addition, normal maintenance, inspections, checks, and measurements are typically undertaken every 4–6 years. This work involves interrupter overhauls, pulling pins on crank boxes and replacing them, cleaning and replacing lubrication, and checking and resetting tolerances. Some utilities choose to undertake all work in-house, whilst others do so under the supervision of the manufacturer's

representative. A reduction in the manufacturers' technical capability is now severely impacting the choices and ability of asset owners to maintain and operate the pressurized head designs. One utility reports that for GE-ATBs major reconditioning work, contracted-in, requiring the replacement of tie rods, interrupter rebuild, gasket and seal replacement, and mechanism work takes a 6-man crew 6 weeks to complete and costs around $200,000.

Service advisories: Many utilities have faced challenges in processing this extra work according to GE. Difficulty in managing moisture in the high-pressure air system and poor lubrication programs are major contributors to mechanism problems. One practice to ensure a full complement of strategic spares is the sourcing of spare components from locations where circuit breakers have become redundant.

Many air blast circuit breakers (ABCBs) are approaching, or are at, their manufactures design lives. Together, with maintenance complexity and the lack of technical experience, both internally and externally, utilities are adopting strategies that require the replacement of their ABCB fleet.

5. HV/LV Switches

For many companies, the driver for a comprehensive review of disconnects tends to be triggered by the poor performance of one particular design.

There is an operational perception across a few utilities that disconnect and ground switch performances are skewed by poor reporting. As a large population of switches are manually operated, and as most defects are found during operation and immediately rectified, it is likely these defects are not correctly recorded.

The decision at a few utilities is to replace disconnects as part of a circuit-bay upgrade program, others have chosen a strategy of disconnect and ground switch reconditioning depending on the equipment type. A few utilities have had to modify their ground switches following a rating evaluation where a few designs had insufficient performance.

6. Strategic Spares Equipment

Many companies have invested the effort and resources to optimize strategic spares cover. This includes coordination between all stakeholders (suppliers and customers). The effort requires identifying a replacement strategy for every piece of equipment and priority circuits, setting up cross-functional reviews to identify gaps in equipment spares cover, and developing recovery strategies.

Some manufacturers are offering limited warranties (cables: insulation shrinkage) and free upgrades to the latest equipment, variant on replenishment. In some instances, utilities that have contracted with suppliers for 40-year warranties so hold no strategic spares for specific equipment. Unfortunately, incidents of poor installation practices have had an impact on this approach.

Utilities that have considered limiting the number of new designs introduced have found this has implications for procurement from the potential reduction in competition or need for long-term agreements. There is also the potential increased vulnerability to an equipment-type fault.

One approach to maintenance spares that works well is to issue two kits, one containing all consumables for the job (seals, gaskets, etc.), and the other containing more expensive parts possibly requiring replacement. This approach allows the central stores to order and make up the kits and receive back unused more expensive parts, providing clearer spare quality control, cost recording, and eliminating “squirrel stores.”

7. Protection and Control

For the majority of utilities in North America and internationally, the maintenance intervals for protection equipment are time based; however, intervals have been lengthened and work content has been reduced from historic level.

Performance measures are in place to measure the outcome of protection maintenance work and its alignment with corporate objectives. Some utilities report a lower protection performance for the last 4 years than the expected forecast. This is mainly due to relay failures, high-resistance faults, and human errors. Many utilities are experiencing a definite problem with the competency level of the protection skills. Staff formal certification programs across companies have had some teething problems. The advent of integrated technologies in the light current areas of protection and control has presented utilities with an opportunity to encourage the cross-training of resources.

Increased demands on the power system have necessitated the review of protection setting philosophies for affected utilities. High tower footing resistance is another concern for some utilities.

Many utilities have adopted a program to expand their installation of digital fault recorders (DFRs). This has enhanced the speed and quality of investigations into the power network and protection performance dramatically.

Refurbishment of protection equipment using a score system to evaluate and prioritize refurbishment is a methodology applied in North America, UK, and Africa. Due to changes in their power networks and the application of new technology, utilities are continuously reviewing their protection scheme settings philosophy.

One of the large challenges facing protection maintenance is the effect on load growth expansion. This has caused the allocation of protection maintenance resources to support commissioning activities and constrained the availability of maintenance outages.

8. Phase Conductor

Recently, a few US utilities have been investing field time into evaluation of Electro-Magnetic Acoustical Transducer (EMAT) technology for detection of broken strands internal to conductors and attachments. The technology is applied on an energized line using bare-hand techniques and is able to identify conditions in which several broken conductor strands exist within the region of attachment to the support structure. The EMAT unit generates microscale displacement waves that are propogated through the conductor under investigation. By analyzing the conductor response to the combined torsional and longitudinal excitation, the EMAT unit will report the conductor condition. Advantages of EMAT are:

- Much more amenable to inspections of parts with complex geometries than conventional transducers
- Able to overcome many of the common problems encountered with traditional ultrasonic techniques, in addition to being non-contact
- Works at high temperatures and passes through various coatings while scanning at high speeds
- Less prone to operator error and produces a more repeatable variety of ultrasonic wave.

9. Wood Pole Structures

Utility commissioners are increasingly involved in agreeing with wood pole inspection programs and monitoring a utility to ensure its performance remains compliant. This has been common practice for a number of years in California and began affecting investor-owned Florida utilities in March 2006.

The approach to wood pole inspection varies due to a number of justifiable factors. One factor that is common to all utilities is the high integrity of line staff. The challenge for most companies appears to be demonstrating adequate control, overview, and audit of their inspection programs.

Some utilities in North America and internationally are taking the lead in identifying initiatives, such as disaster preparedness, recovery programs, and increasing collaborations with local governments.

10. Underground Cables

The many different types of cable complicate utility cable replacement programs. Work priorities are normally based on environmental, safety legislation, and the rate of deterioration.

For utilities, the issues of reinforcing tape corrosion, lead sheath fatigue from intercrystalline cracking, and oversheath damage due to poor backfill practices have forced some to undertake the replacement of cable sections or change their operating practices. One approach to reduce the number reinforcing tape breakages was to reduce oil section pressure by installing additional stop joints.

Modern sheath voltage limiters have prompted some utilities to review their circuit bonding schemes, resulting in a significant reduction in the number of bonding link boxes and future maintenance costs.

Where insulation thermal aging is not significant, some utilities are refurbishing their cable auxiliary systems. This work has lead to a significant reduction in oil leaks and includes:

- The installation of cable leak detectors in joint bays and the reinforcing of the joint-to-cable-end plumbs
- The installation of pressure transducers for detecting oil pressure drop

Some of the areas that utilities are looking at to improve the cable performance include:

- Temperature monitoring using fiber-optics for real-time rating
- Improved thermal backfill

11. Rights-of-Way

A 6-month transmission Rights-of-Way (ROW) visual aerial inspection is common in the US. Driving and foot patrols vary from 12–36 months. Typically, maintenance is undertaken on a 4-year cycle and consists of tree trimming, herbicide, and bush hogging.

US regulating bodies have already begun asking for information regarding ROW maintenance. It is expected that commissioners will either issue guidance on ROW maintenance (as is done in California) or require individual utilities to present a program and demonstrate compliance with the defined program. Although many utilities would consider extending the ROW program interval, it is seen as politically inexpedient following the August 2003 blackout. Many companies are convinced that their transmission programs are satisfactory, and a few consider sub-transmission in many ways more important.

ROW information is provided on many utility websites. Guidance is given on minimum foot radius around the base of each transmission pole or from a 4-leg transmission tower and anchors. Encroachments are normally forbidden under or within 15-feet of any power line conductor and are not to exceed 12-feet in height. Within the ROW, some utilities will allow parking lots, grading, excavation, and the changing of drainage patterns, provided they comply with the utilities' requirements. Typical corridor widths, unless otherwise specified in the ROW agreements are:

- 100kV, minimum 68-foot
- 230kV, minimum 150-foot
- 525kV, minimum 200-foot

PRIORITY 2 ASSETS

1. High Pressure Air Systems

Utilities with central air systems find they generate a large number of defects and corrective work. In the Northeast US, some systems are more than 40 years old. In the UK, many designs with a history of poor performance have been replaced with modern air boards and compressors. One driver for replacement is the relative cheap cost of modern equipment and superior technology. Some utilities have undertaken condition assessments of air systems as part of substation security projects. The replacement of air systems is the preferred option to refurbishment. Utilities that have implemented an appropriate level of air system remedial work have recorded a significant improvement in their system performance.

2. SF6 Circuit Breakers

For most utilities in North America and internationally, their fleet of SF6 circuit breakers have been in service for almost 30 years and a large population is around 20 years old, well short of its anticipated life.

One factor influencing the remaining life of SF6 breakers is their operating duty. Many beakers used for switching reactors are approaching or exceeding their design operating life due to frequent switching. This has necessitated review of their lifetime management strategies.

Gas pressure alarms remain a significant operational source of fault reports, and utilities are attempting to address this by closer attention to site-inspection gas-level recording or by the application of continuous monitoring systems.

Utilities continue to review their maintenance regime for SF6 breakers, focusing more on condition monitoring and inspection. Experience has shown that periodic interrupter inspections at 12-year intervals is generally inappropriate and that maintenance targeted on the basis of operating duty and/or operating experience is more valuable. Some utilities are negotiating with manufacturers to consider the reconditioning of mechanisms, whilst others are considering employing a dedicated refurbishment facility, using “traveler” units to replace those units removed.

3. Metalclad Switchgear

Most metal clad circuit breakers are periodically overhauled between 4–8 years in North America. Many utilities are moving towards a diagnostic plan approach, by reviewing familiar measurements before undertaking a full overhaul. Measurements include annual thermography findings, number of breaker operations, functional checks, and visual inspection, including moisture in any form from building leaks or condensation.

4. Power Line Carrier

For most utilities, their current available records are inadequate to ascertain whether condition-based or reliability-centered maintenance provides an optimally cost-effective approach to power line carrier maintenance. The common strategy for maintenance is a time-based philosophy applied to each essential component of the power line carrier-link. The require maintenance interval of each component varies, between annual inspections, normally non-intrusive work to a more comprehensive six-year measurement of performance characteristics.

Some utilities are reviewing their power line carrier systems for bottlenecks, resulting in poor protection system signaling performance and the need for diversity using other privately owned systems. Spares are an issue on some obsolete equipment, and one strategy is to maintain refurbished units for parts to ensure acceptable return to service times following failure.

5. High Voltage Instrument Transformers

Utility testing of instrument transformers depends largely on the experience of each manufacturer's product line in service. Although manufacturer's instructions usually state that such testing is not required experience in service indicates that periodic testing is required. If there has been no history of problems in service, insulation power factor testing and oil analysis, where practicable, typically start after about 10 years in service and repeat every 5–10 years for some US utilities. Other utilities only trigger power factor testing from a suspect oil analysis. The lower voltage class CTs such as 138-kV and below are seldom tested in service unless there has been a record of problems on a specific brand. Commercial on-line monitoring products monitoring leakage current and hydrogen in oil are utilized by utilities on an as needed basis. Some utilities in the UK have initiated programs to replace whole families of suspect CT's following investigation into catastrophic failures

6. Revenue Metering

There appears to be no significant issues with revenue metering equipment across utilities. Failures are noticed early due to the continuous monitoring of their data output. Due to this high visibility (continuous data recording), and the expectation of high metering performance to satisfy compliance codes, some utilities expect to replace their revenue metering equipment before 20 years of operation.

7. Station Insulators

The condition of anchor bolts on tension insulator sets, specifically at substations located in contaminated environments, is being observed by UK utilities. Concern about the performance of LAPP strain insulators has some North American utilities programming their replacement. The practice of insulator greasing to limit the impact of contamination has been stopped at many utilities. They now favor triggering the washing of insulators based on contamination information collected at monitoring sites. A recent event in South Africa proves this approach is vulnerable where washing is subsequently delayed.

8. Station Cables and Potheads

Compared to circuit cables, the knowledge of the condition of substation cables is generally poor across utilities. For a large amount of the population only on-site maintenance records exist, reports in the computerized maintenance management systems on condition are very poor. For the past couple of years a number of utility initiatives have been underway to update the technical database and better establish the condition of substation cables and potheads. Maintenance of cables is dependant on the cable type. For cross-bonded cables, routine cable sheath tests and oil pressure checks are common practices. Some pothead types have experience signs of ferrule pull out, but these problems are very rare.

9. Batteries and Chargers

For many utilities, overall battery status typically relates to criteria such as the batteries capacity compared to its manufacturer's rating, current design requirements, ability to hold charge, and its level of service life.

Utilities continue to look at the case for alternatives to substation batteries. One driver is the consideration of alternatives for batteries in remote areas, where proper maintenance is difficult or costly. However, a recent survey by EPRI found the life-cycle cost of lead-acid substation batteries are extremely inexpensive, and matching them on cost—even on life-cycle cost—is a difficult task, especially when some utilities are satisfied not to perform any maintenance on them at all.

10. Station Grounding Systems

The type of tests performed as routine preventative maintenance and their frequency remain decisions of individual utilities based on experience with their systems. In addition to the routine site inspection, a large portion of utilities only tests their grounding system when trouble is indicated. Theft of ground conductors is a major issue for utilities. South Africa has significantly reduced theft by working closely with bulk metal purchasers. Most utilities perform condition assessment on ground systems when a change to the site has, or is due to occur.

11. Capacitor Banks

Due to their electrical characteristics, capacitors are susceptible to conditions that can reduce the expected life of the individual capacitor. The practice of some leading North American utilities is to protect the capacitor "cans" with an individual fuse.

Common utility practice is to visually locate and then test any capacitor found with a blow fuse. Maintenance triggers vary, from number of bank operations, system fault events, or an inspection task. During maintenance, any capacitor suspected to be damaged (i.e., bulged tank, partial shorting, per test results, etc.) is replaced.

12. Station Buildings

Some utilities have tried surveying civil inspections on a 5-year interval; in practice, surveys were given a low priority and were deferred.

Rather than undertake routine inspection, many utilities engage in regular programs to review common aspects of buildings. Buildings are categorized by age. Assessment programs may include flat roof replacement, window and air conditioner upgrades, painting, concrete and surface repair, and restroom facility and mess area updates. Programs are planned a couple of years ahead. In some cases, work is held-off and only called upon to manage budget under spends.

13. Fences

Security in the US and internationally consists of physical perimeter fences fitted with tampering monitoring, locked equipment cabinets, electric gates, and door sensors. Electric fences are common in the UK and Africa, but only South Africa operates fences in the fatal mode.

The UK companies have removed fence signage from many of their substations, preferring the facility to remain anonymous. The practice in the US and UK is to visually inspect the substation fence monthly for interference.

14. Drainage and Geotechnical

The life of a drainage system is affected by the original workmanship, maintenance, and overstressing with abnormally heavy loads. Utilities report drainage lives can span 25–80 years. Drains are prone to collapse, problems due to ground movement, and blockage, all of which can substantially reduce their life.

A number of US utilities only note the effectiveness of drains following a storm. European environmental standards have forced utilities there to enhance their drainage systems. Utilities routinely inspect sites for standing water and separator discharge to ensure drainage integrity.

NGC has prioritized several hundred substations by the volume of oil on site, local soil type, and the vicinity of local aquifers.

15. Fire and Security Systems

In the US, a few utilities are reevaluating their substation fire risks. West coast utilities appear more active in this area. However, some US companies have no concern due to the spatial separation between their transformers.

Leading utilities perform a monthly system visual inspection, two-monthly fire pump operational checks, annual fire panel checks, and two-yearly functional and system performance checks (deluge valve operation).

Oil volume is the metric used by most utilities to determine the National Fire Protection Association (NFPA) recommended separation distance, specifically NFPA 850: Recommended

Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations.

Many US utilities have transformer and oil filled reactor configurations that are non-compliant to NFPA codes. Their insurance carriers are aware of this situation but neither party appears active in finding a solution. Many report they have a challenge retrofitting firewalls to existing installations due to electrical conductor clearance and to a lesser degree cooling.

Fire project upgrades are normally complete in 18–36 months, based on complexity. Typically, US switchyards have a fire barrier wall between transformers and adjacent buildings. Most have automatic deluge systems. Foam and CO_2 extinguishing systems are very rare. For substations located in rural areas, the use of passive fire protection in the form of spatial separation, 150–300 feet is common.

An Enterprise Security Initiative is the approach adopted by many US utilities, evaluating physical and cyber vulnerabilities. Penetration tests to determine IT system vulnerability are now common. UK and US utilities have removed system layout maps from their websites.

PRIORITY 3 ASSETS

1. Protection System Monitoring

Although protection system monitoring is common across utilities, technological advances mean utilities remain in the proving stage for integrated system monitoring equipment. The interval for testing sequence of event recorders and digital fault recorders is 3–6 years. Quality of supply, on-line system stability, and dynamic system monitoring devices at some utilities are maintained under service level agreements. These support agreements are becoming more popular in the UK and South America.

2. Station Buses

One cause of disconnect switch binding has been attributed to the movement of bus bars on the outer post insulator. This has occurred in the UK and North America. The issue is typically found on sites built on a bed of pulverized fuel ash. Some companies in North America undertake Corona inspection of buses on a six-year cycle.

3. Station Surge Protection

Surge arrester field tests are not tests of the complete protective characteristics of a surge arrester. This is due to the voltage and current magnitudes necessary to replicate an event and the limitations of available field test equipment. Instead, they are tests of the mechanical condition and insulating quantities of an arrester. As an arrestor spends most of its life as an insulator; verification of these quantities is essential.

Many US utilities operate effective assessment programs. They undertake monthly visual inspection to check for loose hardware, cracked porcelain, and cement. The surface is checked for contamination and signs of flash over. These checks are supported by an annual thermography survey. Routine leakage current measurement is performed on insulated-base type arresters where the ground lead is accessible. Some arresters have a grounded-base with no accessible ground lead, making this test impractical. Some US companies perform a power frequency dielectric-loss test with Doble test equipment every 5 years.

4. AC/DC Service Equipment

Recognizing the varying configuration of AC and DC substation services, a number of utilities in UK, South America, and Africa are undertaking surveys. For each substation, the focus is to document the number of incoming supplies, availability of standby generators, and the provision for automatic change over. The conditions of these components are being scored together with battery systems and central air system schemes. The driver behind these assessments is to ensure substation black start capability.

5. HV/LV Station Structures

Utilities trigger concrete structural repairs from routine site inspections. Deterioration is found to vary with the quality of the original workmanship and materials. Cracking of concrete from an

alkali silica reaction is reported by many utilities normally around bolts. Routine site inspections trigger the filling of cracks to prevent further deterioration from “frost-jacking.” Carbonation is the most common form of deterioration that affects concrete structures, but successful repair methods have been applied in the UK. Modern concrete specifications virtually eliminate this problem. Where chloride accelerators were used in the original mix or are absorbed from salt spray, deterioration is difficult to combat. Utilities are identifying these structures, typically pre 1970’s, for replacement. One challenge faced by utilities is evaluating the success of repairs. Repairs take time to evaluate with certainty, during which new techniques can make past repair practices redundant.

Most steel substation structures either are galvanized or have zinc spray protection. Routine site inspections record any visible rusting. The treatment is spot painting following a thorough preparation. Most visual inspection programs focus on areas where water can collect, especially the concrete-to-steel junctions where a steel member is encased in concrete at its base.

Some utilities have planning models working with a 55–80-year asset live range, with poor concrete types at the lower range and steel at the higher.

6. Heating, Ventilation and Air Condition

Some ventilation schemes associated with long cable tunnels are maintained by service level agreements with the original manufacturer. Many of these schemes are integrated with a fire protection system for smoke control. Heating and air conditioning performance is recorded during routine substation walkdowns.

7. Boilers and Pressure Vessels

The pressure reducing and relief valves fitted to boilers and pressure vessels are tested in the UK on a 6-year cycle. NGC has developed its own high-pressure test rig. This rig is only operated by authorized personnel to test reducing and relief valves.

8. Oil Containment Systems

The monthly inspection of oily water separators, site drain discharge, and berms are part of the routine site inspection program for many utilities. Programs to assess the effectiveness of ground grading, directional curbing, ditches, earthen and concrete pits, liners, and crushed stone areas tend to be one-time reviews than common routine inspections. Many US utilities are engaged in the improvement of environmental protection measures in the following areas:

- Drainage upgrade in the form of sloping away the path of potential oil spills from buildings and adjacent transformers.
- Curb areas and pits around transformers are being constructed, and a layer of uniformly graded stones is being installed as a means to minimizing ground fires.
- Oil separation systems are being upgraded at sites that have a significant number of fire suppression systems, typically switchyards and DC converter stations.

The approach in the UK is to rank sites by oil volume, soil type, position to aquifers, and surface water, undertake soil sampling, remove contaminated soil, and upgrade drainage systems.

9. Oil and Fuel Handling Systems

Increasingly, environment acts are giving environment agencies the power to serve notices to utilities to carry out specified measures to prevent operations/activities giving rise to a risk of pollution. One of the responses from utilities to minimize the pollution risks from oil-containing plant in substations is the decommissioning of fixed oil-handling systems.

Fuel, insulating oil and lubricating oil-handling systems are found in generation switchyards due to their close proximity to the generating station. Although very uncommon, there have been incidents where the incorrect fluid was used in filling a transformer.

10. Microwave Radio Systems

Microwave solid-state technology remains a strong backbone for utility communications around the world. Dual antennas have been used to compensate for any path movement or losses. Utilities engineers report that once the path is set up and the system is running correctly with routine condition maintenance, the integrity of these systems is good.

11. Fiber Optics

To achieve the maximum flexibility of the fiber network design in substations some UK utilities are utilizing a star-configured infrastructure from the central location to each satellite location (bay) within the substation. Optical fiber systems are tested in the UK to the general requirements of BS 7718. For US utilities, the planning and usage of fiber cable is relate to the experience gained from the reliability of fiber systems as systems are migrated from current analog to digital communication systems. BPA has settled for cable sizes of either 36 or 72 for its looped communication systems.

12. Metallic Cable

Pilot circuits found at utilities in the US and UK are multicore or multipair cables. They are used for alarm, protection, telecommunication, or control purposes. To protect the substation supplies from experiencing damage-induced voltages that the pilot circuit can experience, barrier equipment is used at the interface between the substation wiring and the pilot circuits. Routing testing in the UK consists of a 2kV AC test between the two pilot connects, and a 15kV barrier performance test.

13. Site Entrance Protection Systems

Some northeastern US utilities have a dedicated armed security force managing all aspects of site security. There is a tendency towards outsourcing video surveillance monitoring. Electric gates have been installed at the majority of UK transmission sites. Electronic keys and a tiered level of authorized access are common across utilities. These systems are maintained by service-level agreements with manufacturers. Routine station inspections monitor the systems for anomalies.

14. Teleprotection Tone Equipment

Typically, protection signaling is the key component affecting the performance of control and protection equipment. Modern teleprotection is being installed by all utilities. The current policy is to combine intertripping and signaling functions in one product. One favourite is ABB's NSD70C, a more recent development and effectively supersedes the NSD70 and NSD72. It does rely on user settings to define its operating parameters. The need to specify the settings correctly for each function is required to ensure that the protection system performance is optimized. Testing is typically undertaken in-house, and one requirement is an operational functional check.

15. Line Steel Structures

Although many towers have been painted during their lives, it is believed that not all were painted before loss of galvanization has occurred.

During routine inspection, hand-held data inputting devices have been used to input tower steelwork condition data. This has succeeded in collecting tower condition data in limited and varying degrees. Condition assessment covering foundations and tower steel work ranks towers from: insignificant signs of steelwork corrosion - tower painting within 'X' years - major steel work treatment - or member replacement within 'X' years - to action required to maintain structure integrity.

Some US utilities repaint or recoat when corrosion exceeds 15% of the surface area of the steel pole. One recommendation to extend tower live well beyond 100 years is to paint new towers immediately in order to protect the galvanizing, followed up with a good maintenance painting strategy.

Another suggestion is the use of new cross-arm designs that unbolt individually, allowing easier replacement.

Some US utilities plan to complete ground resistance measurement of their entire steel tower population over a 20-year cycle.

16. Line Shieldwire and Hardware

As part of the routine visual patrol, US utilities inspect the ground wires at a number of positions for damage associated with the wire span, dead-end assemblies, wire bonding on compression anchor clamps and damage to the bonding on suspension clamps. As with the phase conductor assessment, Electro-Magnetic Acoustical Transducer (EMAT) technology is being considered for the assessment of the shield wire to detect broken strands internal to the wire and attachments.

17. Line Insulators and Hardware

Insulators can be defective with no visible signs of the defect. The reason these defects cannot be seen is that they occur as a crack through the cement under the metal cap. This creates a short between the cap and pin. Utilities replace defective insulators or full strings using live- or

dead-line techniques. One common method used is a portable, megohm-meter type instrument which allows linemen to "meg" insulators on lines up to 500-kV with the line energized or de-energized.

2008 Vegetation Management Program Review

Hydro One Networks Inc.

System Investment Division

Distribution Development & Lines Sustainment Department

Distribution Lines & Rights of Way Section

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March 12, 2008

Introduction

Objective

The objectives of this report are to review Hydro One's Vegetation Management Program, to identify improvements that can be made in managing vegetation, and to obtain a better understanding of the variability of cost and reliability compared to maintenance intervals. The report will also consider other program related factors (e.g. safety, reputation) along with implementation constraints such as funding levels and labour resources.

Method Summary

Hydro One's Vegetation Management Program was analyzed in three parts:

(1) *system reliability*

(2) *cost efficiency*

(3) *benchmarking (both reliability and cost)*

Analyses were focused around clearing cycles (i.e. system average time between maintenance) and their relationship to reliability and cost. System reliability results were incorporated into a cost savings curve related to *demand* (i.e. trouble call, storm damage, unplanned activities) expenditures. *Planned* expenditures were examined independently based on current Hydro One costing information and the experience of vegetation management experts (i.e. CN Utility) to determine how costs would change with cycle length. Finally, benchmarking data was explored to incorporate industry experience into the analysis and to assess internal findings.

Background

Vegetation growth has a significant effect on the reliability of Hydro One's distribution network. A strong majority of overhead line incidents are caused by trees coming into contact with the line; overgrown brush increases outage durations by making feeders and equipment more difficult to access during power restoration efforts. The condition of vegetation on a distribution right-of-way has proven to be – by a considerable margin – the dominant influence on system reliability during storm events. In recent years, Hydro One's maintenance accomplishments in line clearing and brush control have placed the system on an average cycle of approximately 10 years. This means that the average feeder in the system was cleared after 10 years of growth, although some feeders were cleared more

frequently and some less, depending on numerous prioritizing factors such as reliability performance, system voltage, customer requests, types of tree species, and geography. The industry benchmarking data presented later in this report and obtained through participation in the 2006 Tree Line Connection (TLC) Vegetation Management Benchmarking Study, shows how Hydro One is in the upper maintenance cycle range when compared to other North American utilities. The majority of utilities on record are operating between 4 and 6 year cycles.

Reliability Analysis

Impact of Vegetation on Reliability

The following charts illustrate the breakdown of major categorical causes as they contributed to Hydro One's System Average Interruption Duration Index (SAIDI) between 2004 and 2007:

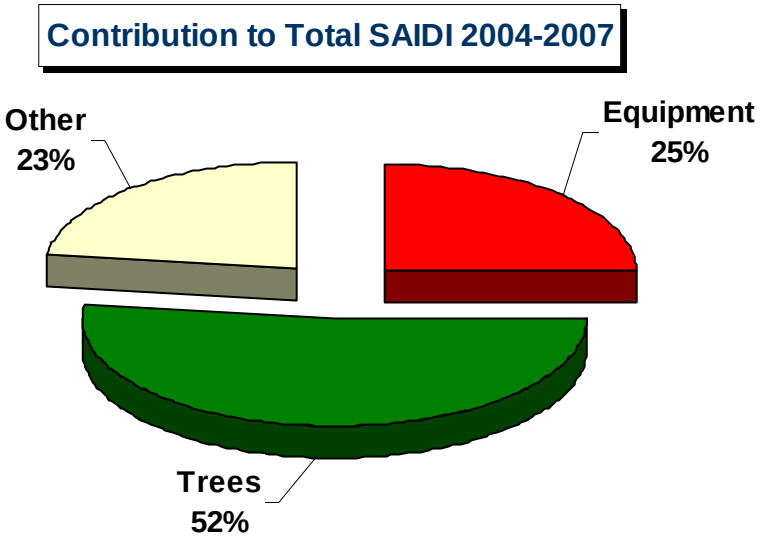


Figure 2.1: Contribution to SAIDI by high level cause

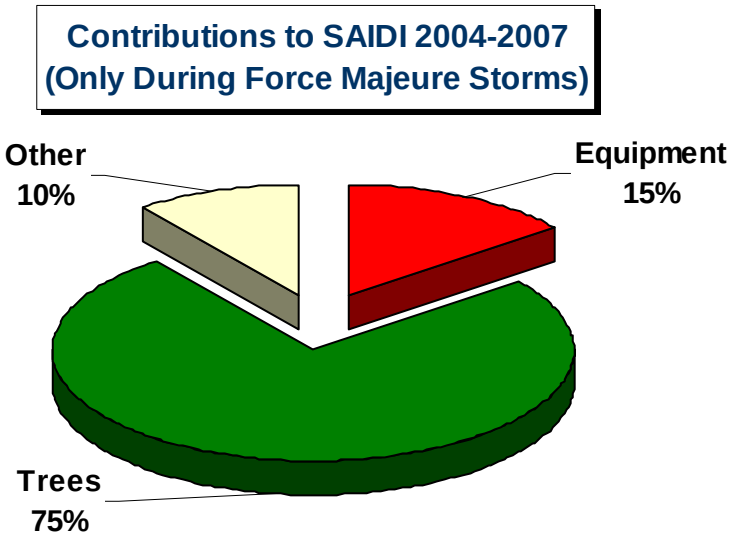


Figure 2.2: Contribution to SAIDI by high level cause during Force Majeure Storms

Figures 2.1 and 2.2 show that trees are responsible for more than half of the overall system SAIDI and that they account for three quarters of SAIDI during storm events. It was apparent from these values that improvements in the Vegetation Management Program could translate into a noticeable improvement in overall reliability.

Reliability Relationships

Hydro One compared *customer interruptions*, and *customer hours interrupted* per km, versus the number of years since maintenance (i.e. line clearing) had been performed on feeders.

Hydro One clearing data was not available prior to 1998; as a result, 2007 was the only year containing data points that represented nine years of growth (for rights of way cleared in 1998). Similarly, there was only two years of data relating to rights of way on an eight year cycle (2006 for ROWs cleared in 1998 and 2007 for ROWs cleared in 1999). Due to the small population size for these durations, the confidence level in the data was low and they were removed from further analysis, which left feeder data for durations between clearing of up to 7 years.

Results were broken up into force majeure and non-force majeure categories. Hydro One's force majeure definition includes events and all storms, where greater than 10% of all Hydro One customers were without power.

The first seven years of charted data below were drawn directly from Hydro One's reliability data. These years were then used to build a model predicting future interruptions based on the average of best case (linear regression) and worst case (exponential regression) scenarios

The results of the analysis can be found in the illustrations below.

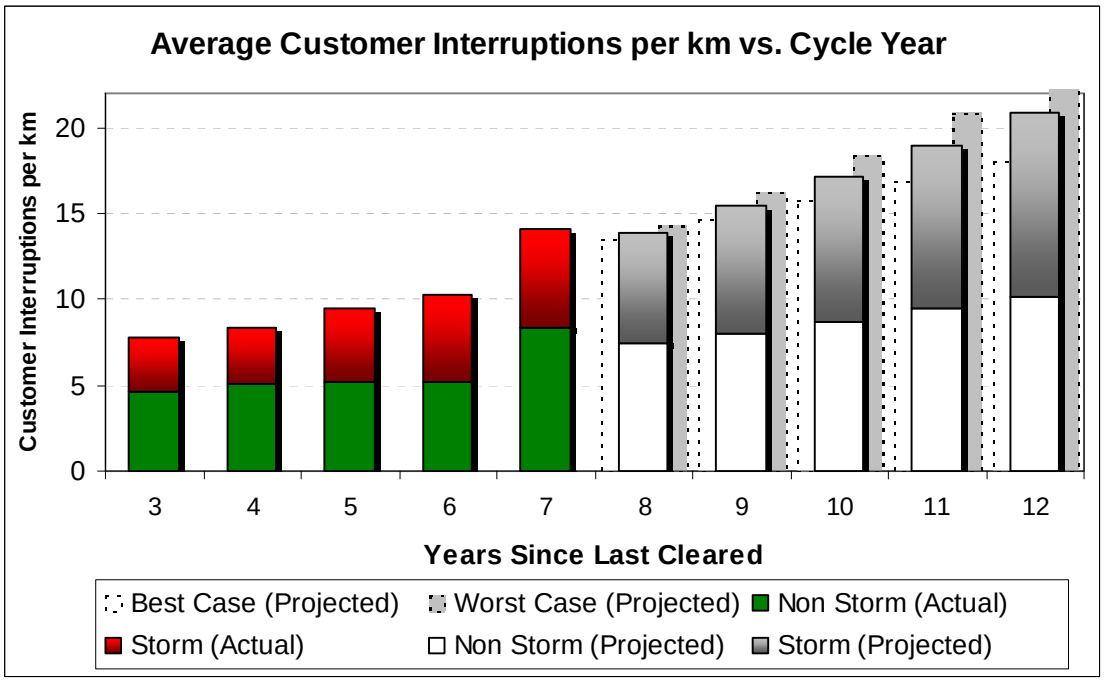


Figure 2.3: Average Customer Interruptions per km vs. Cycle Year

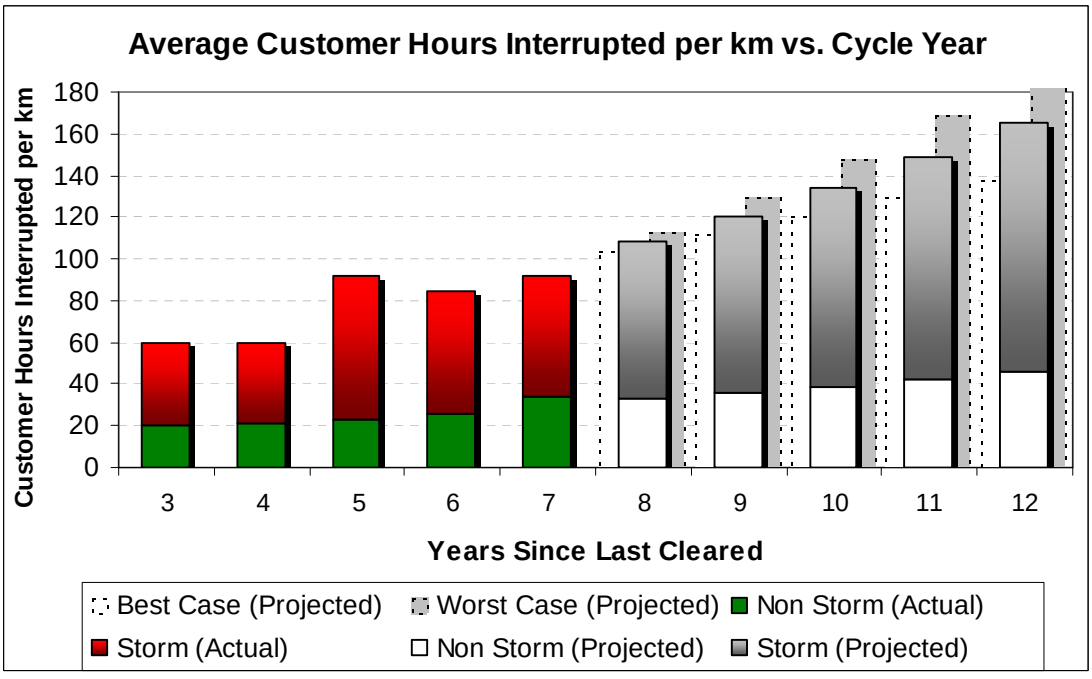


Figure 2.4: Average Customer Hours Interrupted per km vs. Cycle Year

Figures 2.3 and 2.4 clearly showed an increase in the number of interruptions across the system as vegetation was allowed to grow. Once this model had been determined, it was possible to predict the changes in system reliability measures if Hydro One were to operate on a specific line clearing cycle. The resulting plots can be seen in Figures 2.5 through 2.6 below.

Hydro One is currently operating on the equivalent of about a 10 year line clearing cycle. The figures displayed how much the reliability measures would change per year relative to a10 year cycle if an alternative cycle length was in effect. The reliability improvements increase as the cycle length is decreased, which is what would be expected.

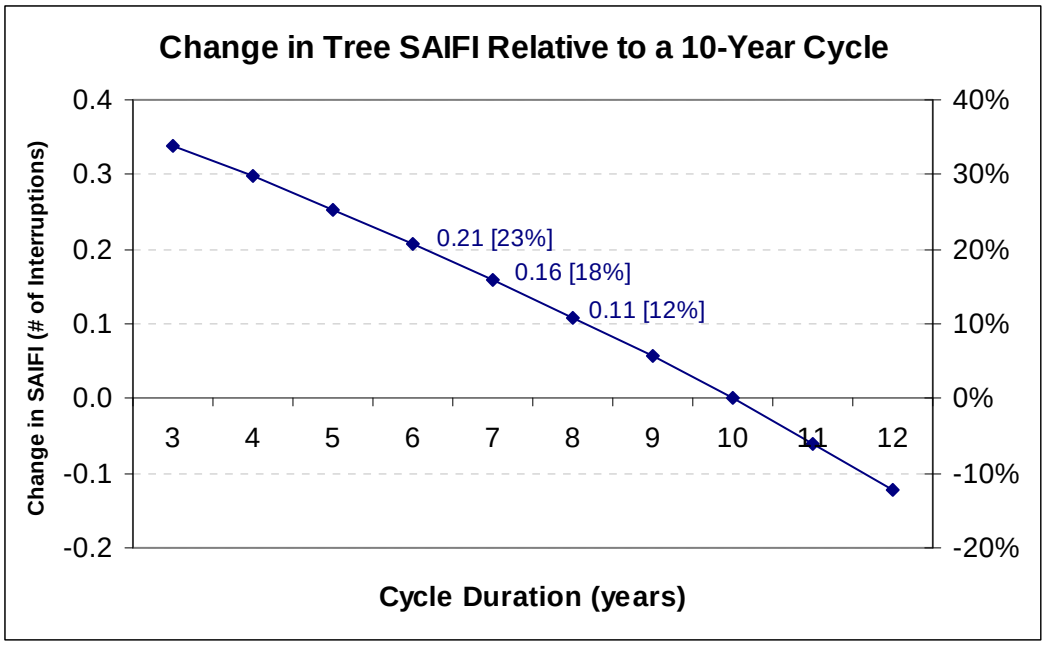


Figure 2.5: Change in SAIFI relative to a 10-year cycle

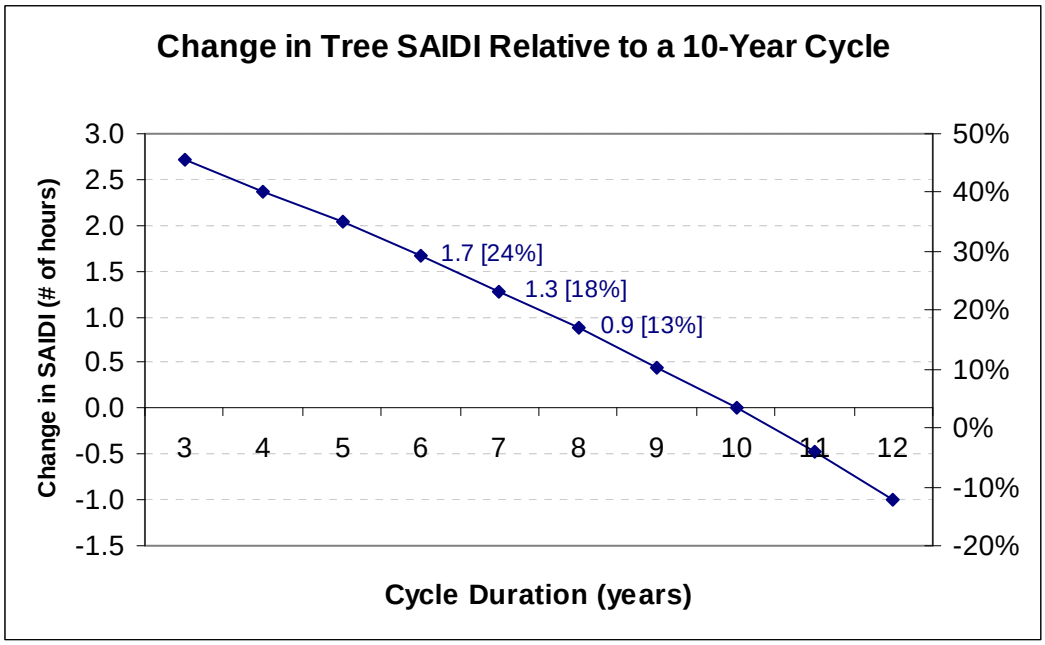


Figure 2.6: Change in SAIDI relative to a 10-year cycle

Figures 2.5 and 2.6 have a second y-axis to the right of the plot. The values on this axis are the percent changes compared to the base value at 10 years.

Cost Analysis

Demand Program Costs

The reliability relationships showed that the longer vegetation is allowed to grow before being cleared, the more tree-caused outages there will be along the right-of-way and the higher the demand costs (e.g. trouble calls, storm damage) will be. Demand costs for a 10 year clearing cycle were taken based on the budgeted costs for 2008. Hydro One's historical reliability data was used to estimate what percentages of the individual programs would be allocated to trees as the cause. The following table is a summary of these program costs:

Table 3.1: Total Corrective Costs ($ million) Caused by Trees (Based on 2008 Budget)

Program	2008 Budget	% Caused by Trees / Brush	Total Caused by Trees / Brush
Storm Damage	$26.0	71%	$18.4
Trouble Call	$52.9	31%	$16.4
Forestry Storm O&M	$6.0	63%	$3.8
Dx Unplanned Maintenance & Customer Requests	$6.0	100%	$6.0
Total	$90.9		$44.5

Demand costs are closely related to the total number of interruptions per km and as a result, it was possible to predict the corrective costs at alternative cycle lengths. The change in reliability is based on number of interruptions for the cycle length in question and applied to the total tree caused demand cost corresponding to a 10 year cycle, resulting in the following table of demand costs:

Table 3.2: Table of Predicted Demand Costs ($ million) by Cycle Length

Cycle Length	% Savings	Reactive Cost
3	26.01%	$33,226,285
4	22.64%	$34,738,122
5	19.17%	$36,295,704
6	15.59%	$37,902,579
7	11.90%	$39,562,607
8	8.07%	$41,279,995
9	4.11%	$43,059,325
10	0.00%	$44,905,592
11	-4.27%	$46,824,248
12	-8.72%	$48,821,244

Table 3.2 shows that the demand costs increase as the line clearing cycle length is increased. These values were combined with the *planned costs* (discussed below) to predict the overall financial effect of different line clearing cycles. The planned cost analysis is explained in the next section.

Planned Costs

The goal of the planned cost analysis was to model the relationship between cycle length and the cost of line clearing and brush control. As Hydro One does not have in-house maintenance costing data for the lower cycle lengths, the decision was made to obtain an expert opinion from outside of Hydro One. CN Utility (please refer to Appendix 1 concerning qualifications), an expert in the field of

vegetation management, was retained to model unit costs based on various cycle lengths. The consultant was given key data points: Hydro One's 2008 unit cost of clearing ($6,144/km) and brush control ($2,256/km) on a 10-year cycle and Hydro One's average cost of reclaiming a right-of-way, and information about Hydro One's practices (e.g. right of way width, clearing and brush control methods). The consultant then combined this data with professional experience and accumulated industry data to come up with the unit costs shown in the table below. (Note: Customer Contact unit costs were set to remain constant for all cycle lengths.)

Table 3.3: Predicted Planned Unit Costs by Cycle Length ($/km)

Cycle Length	Line Clearing	Brush Control	Contact	Total Unit Cost
3	$2,250	$750	$632	$3,632
4	$2,363	$840	$632	$3,835
5	$2,481	$958	$632	$4,070
6	$2,853	$1,120	$632	$4,605
7	$3,480	$1,311	$632	$5,423
8	$4,246	$1,534	$632	$6,412
9	$5,180	$1,794	$632	$7,607
10	$6,144	$2,256	$632	$9,032
11	$6,904	$2,737	$632	$10,273
12	$7,733	$3,503	$632	$11,867

Line clearing unit costs increase as the cycle time increases because more branches come in close proximity to conductors, which requires more complicated and costly work procedures. The same is observed for brush: as it approaches the restricted zone around energized conductors, the level of work increases. In addition, once the height exceeds three metres, herbicide application requires cutting these small trees and then applying stump treatment rather than the less costly herbicide applications that can be applied without cutting.

In order to be plotted along with the demand costs, the planned costs were converted to total annual values based on the yearly accomplishments that would be required to clear the Hydro One's approximately 100,000 km distribution system over the length of a given cycle.

Table 3.4: Total Annual Planned Costs by Cycle Length ($ millions/year)

Cycle Length	Accomplish.	Line Clearing	Brush Control	Contact	Total Annual Cost
3	33,333 km	$75.0	$25.0	$21.1	$121.1
4	25,000 km	$59.1	$21.0	$15.8	$95.9
5	20,000 km	$49.6	$19.2	$12.6	$81.4
6	16,667 km	$47.5	$18.7	$10.5	$76.8
7	14,286 km	$49.7	$18.7	$9.0	$77.5
8	12,500 km	$53.1	$19.2	$7.9	$80.1
9	11,111 km	$57.6	$19.9	$7.0	$84.5
10	10,000 km	$61.4	$22.6	$6.3	$90.3
11	9,091 km	$62.9	$24.9	$5.7	$93.4
12	8,333 km	$64.4	$29.2	$5.3	$98.9

The annual planned vegetation costs in Table 3.4 are shown to be highest on a three year cycle. They decrease as the cycle increases and reach a low at about 6 years. After this, the costs gradually increase again with cycle length. The costs are illustrated in the next section.

Combined Costs

The following plot shows the combined annual planned and demand vegetation management costs by cycle length as they were modeled in the last two subsections:

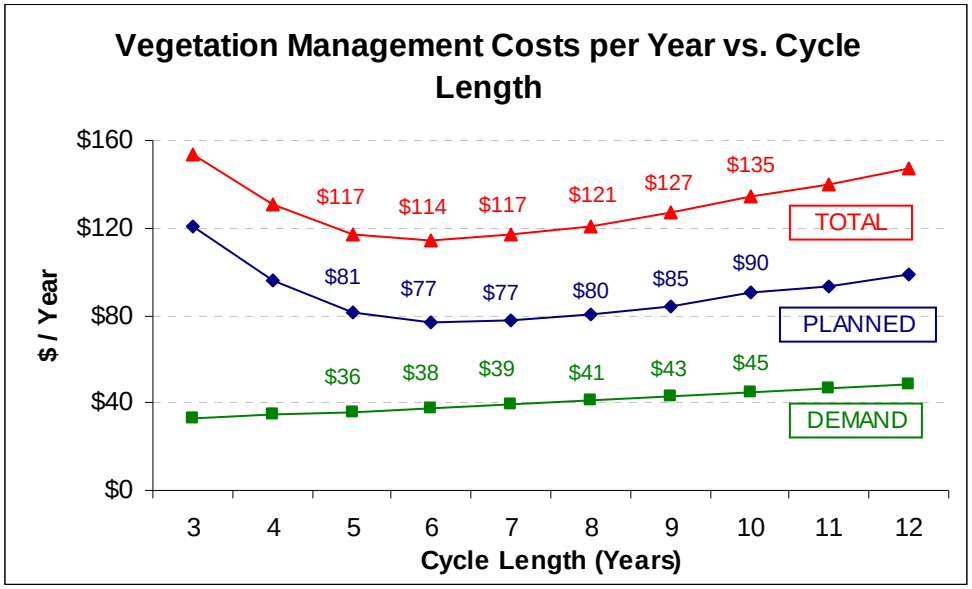


Figure 3.1: Predicted Annual Vegetation Management Costs

It is noted that this cost model focuses on steady state costs and does not include the initial investment that would be required to move from a higher cycle to a lower cycle, which is addressed in the Implementation Considerations section later in the report. In other words, the charts above do not include the added cost that Hydro One would incur from transitioning from a 10 year cycle to an eight year cycle. The ideal cycle length based on cost according to the model is between 6 and 7 years. This would reduce total cost including demand costs from $135 million (10-year cycle) to approximately $114 million per year after full implementation of the lower cycle, and would theoretically reduce tree caused SAIDI and SAIFI by approximately 15% to 25%

Benchmarking

In 2006, Hydro One participated in the Tree Line Connection (TLC) Vegetation Management Benchmarking Study. Information and data from that study were used to benchmark Hydro One's Vegetation Management Program to other utilities within the industry.

Study Background

In total, 48 participants provided data to the 2006 TLC Benchmarking Study. Appendix 2 contains a list of these utilities. As a participant in the study, Hydro One received the raw data although individual utility names were masked. Hydro One isolated comparable companies by using locations (i.e. states or provinces in a similar "hardiness zone"), percentages of rural and remote customers, and excluded municipal utilities.

Cycle Lengths

The following chart shows the cycle lengths for all 23 utilities that provided cycle length data:

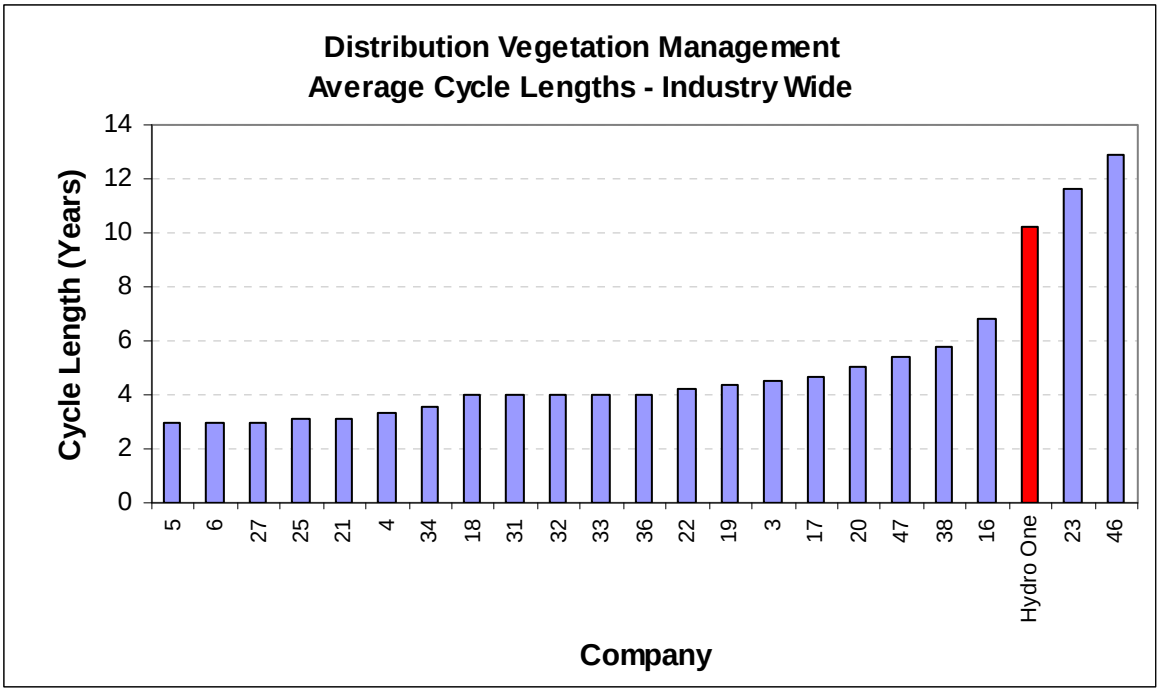


Figure 4.1: Industry Wide Cycle Lengths

Hydro One's cycle length for distribution is well above nearly all of the utilities that reported. When narrowing down to comparable utilities, the results are similar:

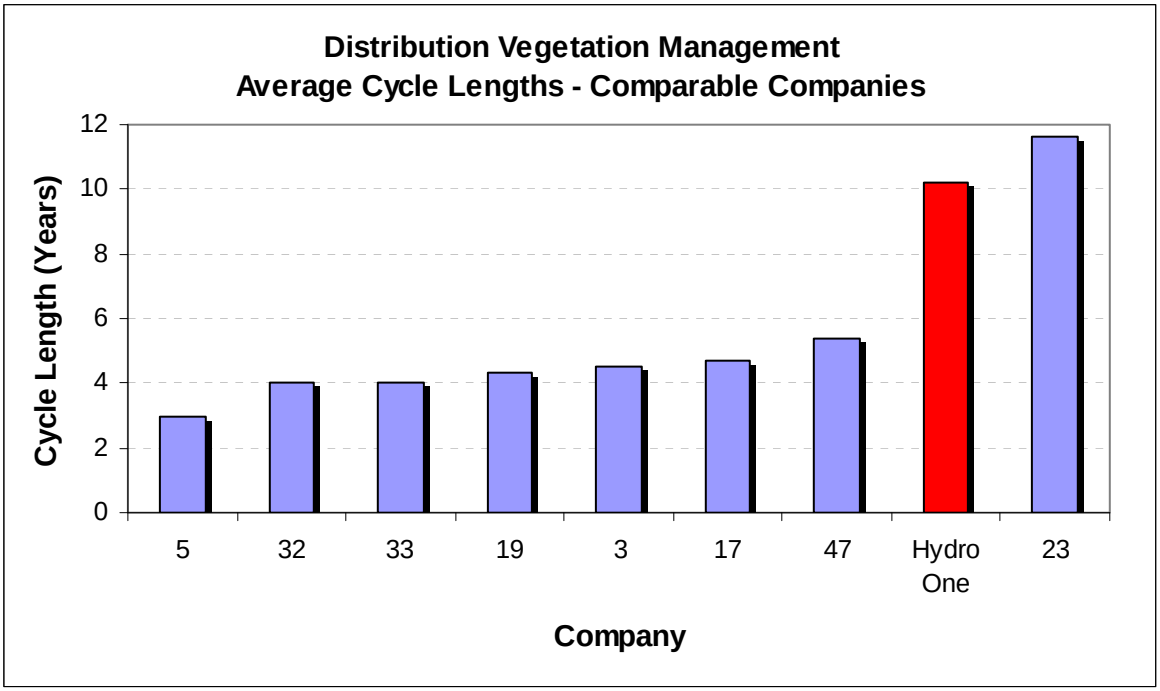


Figure 4.2: Cycle Lengths of Utilities Comparable to Hydro One

Unit Costs

The following charts show the unit costs of vegetation management programs for comparable utilities. The values were gathered by cycle length and then averaged accordingly. The resulting plot is of average unit costs (between 2003 and 2005) versus cycle length. As some utilities reported in Canadian dollars and others in US dollars, exchange rates were factored as illustrated in the first chart below. Since 2005, the Canadian dollar has appreciated considerably and at the time of this report (i.e. 2008) was approximately equivalent to the US dollar. Taking this into consideration, the second chart assumes a 1:1 ratio between Canadian and American currencies.

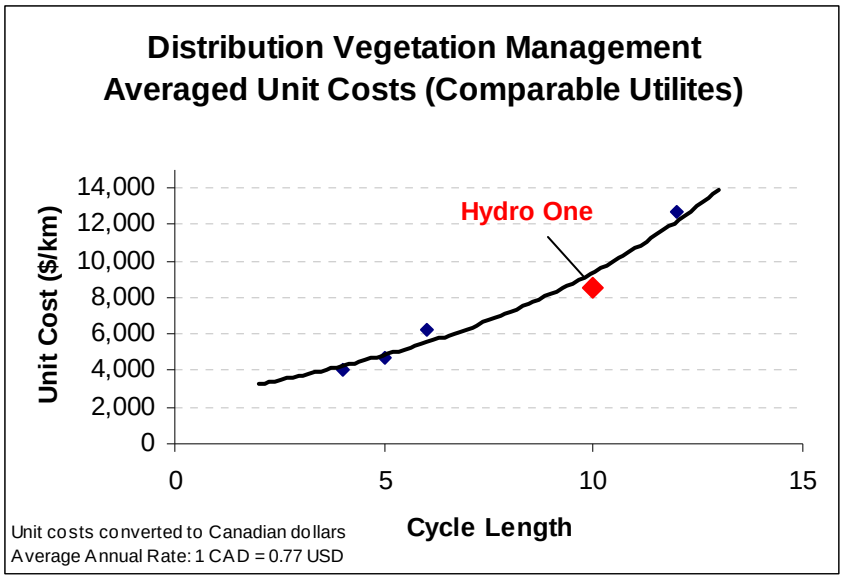


Figure 4.3: Comparable Utility Unit Costs (averaged by cycle length)

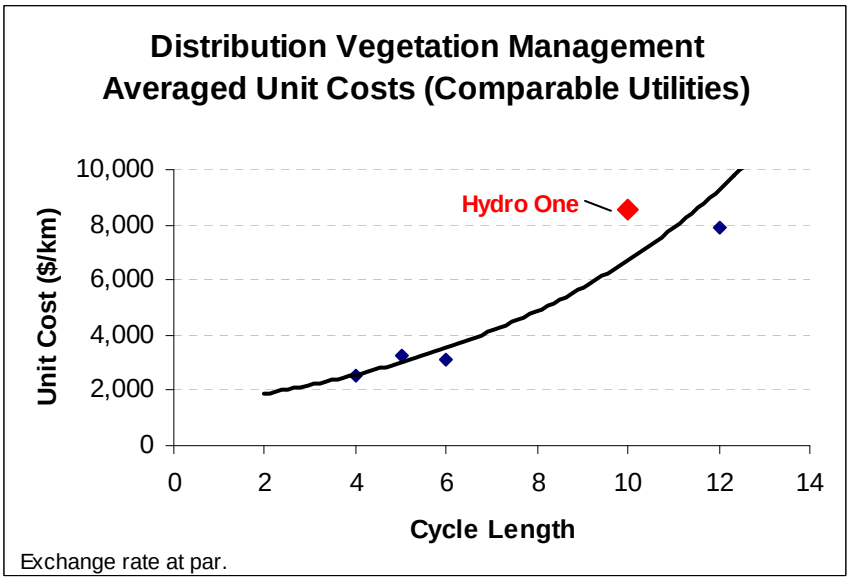


Figure 4.4: Comparable Utility Unit Costs without Exchange Rate Conversion (averaged by cycle length)

As would be expected, Hydro One's system is more costly to maintain than comparable utilities with a shorter maintenance cycle.

Reliability by Cycle Length

The same analysis as that conducted for unit cost was done for reliability but with reported annual tree caused SAIFI as a substitute for unit dollars.

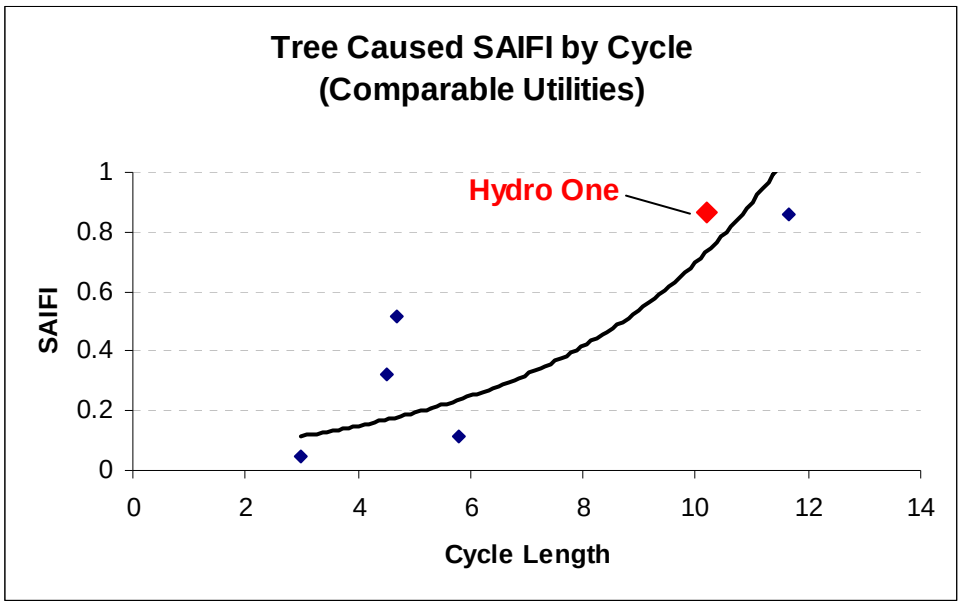


Figure 4.5: Tree Caused SAIFI Averaged by Cycle Length (All Comparable Utility Data)

Other Considerations

Other factors also need to be considered in determining the appropriate Vegetation Management Program. The focus of this report has been to quantify cost and reliability impacts but despite this, there are a number of other considerations that are not quantifiable at this time that need to be identified. The following sections highlight some of these considerations.

Corporate Reputation & Customer Satisfaction

Shortening the vegetation management program cycle could benefit Hydro One's corporate reputation in several ways. The most obvious is through improved reliability. The better Hydro One's service is, the more satisfied the customer will be. Another factor in corporate reputation is the public's perception of Hydro One. A lower cycle length will help to reduce the amount of damage resulting

from storms, which will demonstrate to customers that Hydro One is protecting the public and their property.

Safety

It is noted that Hydro One's safety record has been excellent. However Hydro One does acknowledge that trees that are in proximity of conductors have the potential to come in contact with conductors and may result in safety hazards. A shorter vegetation management cycle will reduce safety risks associated with trees near conductors and will reduce the likelihood of safety issues.

Job Planning and Customer Relations / Corporate Reputation

Job planning is often made more difficult by the presence of mature vegetation on a customer's property. A lower cycle will ease job planning due to a reduced need for drastic vegetation clearing. Fewer tree removals and less line clearing will result in fewer difficult negotiations with property owners.

The Emerald Ash Borer

The Emerald Ash Borer is – out of all future reliability considerations – one of the most troublesome. The exotic beetle is native to Asia and has been ravaging ash trees in North America since its discovery several years ago.

The Honourable Chuck Strahl, Minister for Agriculture and Agri-Food Canada and Minister for the Canadian Wheat Board, in a recent CFIA news release said: "The emerald ash borer is one of the most devastating pests introduced into North America. In only a few years, this population has caused significant ash tree mortality in Southern Ontario."

The prospect of accelerating infestation is another reason to increase vegetation program accomplishments on a yearly basis. The threat of danger trees along distribution rights-of-way will only increase with the ongoing presence of the Ash Borer in Ontario. A shorter vegetation management cycle will reduce the risks that these trees pose.

Summary

Data clearly shows that trees are the largest contributor to poor reliability statistics at Hydro One. The 2006 TLC Benchmarking Study shows that when compared to the rest of the industry, Hydro One has one of the longest clearing cycles, some of the highest vegetation maintenance unit costs, and some of the poorest tree related reliability statistics. The analysis contained within the report, and comparison with other utilities, clearly points to a shorter cycle as being a solution that will improve reliability and reduce long term costs.

Based on Figure 3.1, a 6 to 7-year average clearing cycle (approximately 14,000 km/year to 16,700 km/year of clearing) should provide Hydro One with the lowest long term unit costs. At cycles between 6 and 7 years, the potential exists to decrease the tree component of SAIDI and SAIFI by approximately 18%-24% and annual total costs by up to approximately 15% after full implementation.

Implementation Considerations

Upfront Investment Costs

Moving to a lower cycle will carry with it an initial investment required to bring all of the feeders in the system to the new maintenance cycle. For example, if Hydro One chose to move to a 6 year cycle, the first 6 years would include clearing some feeders that have not been cleared in over 10 years. Because these feeders are more expensive to clear, the cost will be higher during the implementation years.

The full cost of maintaining the current 10-year cycle over the next five years will be approximately $450 million. Moving to a 6-year cycle would cost an additional $125 million in those same five years. In contrast, an 8-year cycle would require only $60 million extra over the first five years. The initial investment required to move to a 6 or 7 year cycle is very high in the short term with full benefits only achieved after the cycle has been fully implemented. To fund this investment, Hydro One would be requesting current rate payers to fund an initiative with limited benefit to them. Hydro One plans to mitigate this concern by first moving to an 8-year cycle with the intention of reducing the cycle even further in future if the cost benefit does prove to be favourable. This will reduce the large initial investment that is needed and ease the burden on current rate payers.

Resources

Another implementation consideration when moving to a shorter cycle is the availability of resources. Moving directly to a 6 to 7 year cycle would require an increase of over 150% compared to those resources required to clear on a 10 year cycle. To implement an immediate increase of this magnitude is challenging for any organization. The more gradual implementation of a shorter cycle length would serve to temper the demand and would make it more likely that resources would be available (or could be trained) to complete targeted accomplishments.

Reassessment Opportunities

A gradual implementation of an optimum cycle by first moving to an 8-year cycle also provides the opportunity to continue to monitor benefits and reassess the return on investment. Once an 8-year cycle is achieved, reliability and cost values can be used to further validate analysis that has been

conducted as part of this report and to confirm findings. Based on this approach, a commitment to a cycle in the range of 6 to 7 years could be made at some time in the future if found to be beneficial and cost effective.

Appendix 1: CN Utility Profile

CN Utility Consulting, Inc. (CNUC) was founded to provide peerless consulting and training services to the electric utility vegetation management industry. [They] offer a wide variety of services to electric utility companies, vegetation management contractors, and professionals in the legal and regulatory arena.

CNUC provides expert consulting based upon fifty years of proven and successful experience achieved through managing the nation's largest, and most scrutinized utility vegetation management program. CNUC was formed in 1999 by Stephen Cieslewicz and Robert Novembri to serve the electric utility vegetation management industry. CNUC brings proven expertise to an industry where few seasoned experts exist.

Mr. Cieslewicz has over 20 years of direct experience as a Utility Arborist and is currently the President and Chief Operating Officer of CN Utility Consulting, Inc. He is also a member of the NERC UVM Standards drafting committee. This committee has developed and is continuing to refine national standards for required clearances between vegetation and transmission lines. Mr. Cieslewicz consults with utility companies, vendors, and regulators on all issues related to utility vegetation management (UVM). Over the years, Mr. Cieslewicz completed various utility and vendor benchmarking projects focused on identifying UVM industry trends and best practices, completed national assessment of current UVM related laws and regulations and has presented at numerous national and international conferences on subjects ranging from “how trees cause power outages” to “customer service for the utility arborist”. He was selected by the Federal Energy Regulatory Commission (FERC) as one of the principal UVM investigators for the Joint US/ Canada Task Force investigating the August 14th 2003 Northeast Blackout.

Working along side Mr. Cieslewicz is Kevin Patton. Mr. Patton has over 14 years of experience in the electrical utility industry (7 years as a Utility Arborist) and is currently the Manager of Technical Services at CN Utility Consulting, Inc where he has consulted internationally with utility companies, vendors, and regulators on all issues related to utility vegetation management (UVM). He has conducted numerous UVM program assessments for North American utilities and has testified as an expert in numerous court cases related to vegetation management and has presented at numerous conferences. He is a member of the IEEE, an ISA Certified Arborist, and an ISA Certified Utility Specialist.

Both individuals are widely recognized as experts and are still sought after in the UVM field. They are highly regarded and accepted by all of our internal experts.

Appendix 2: 2006 TLC Vegetation Management Benchmarking Study Participants

The following is a list of participating companies in the 2006 TLC Vegetation Management Benchmarking Study:

AEP
Allegheny Power
AMEREN Corporation
Arizona Public Service
Avista
BC Hydro Distribution
Central Vermont Public Service Corp
Chelan Public Utility District
Cinergy
Clark Public Utility District
Colorado Springs Utility
ComEd (Exelon)
Consumers Energy
Dixie Electric Membership Corp.
Dominion
Duquesne Light Company
Entergy
Entergy Transmission
Florence Utilities
Florida Power & Light
FortisAlberta
Hydro One
Hydro-Quebec
Idaho Power
Indianapolis Power & Light
Longmont Power & Communications
Lower Colorado Power Authority
Maine Public Service Company
Nevada Power Co.
Pacific Gas & Electric Co.
PacifiCorp
Progress Energy Carolinas
Progress Energy Florida
PSE&G
Public Service Company of New Mexico
Puget Sound Energy
Sacramento Municipal Utility District
Sierra Pacific Power Company
Tennessee Valley Authority
We Energies
Xcel – Northern States Power Co – MN
Xcel – Northern States Power Co. – WI
Xcel – Public Service Company of Colorado
Xcel – Southwestern Public Service Co.

Comparable utilities were selected on the basis of three criteria:

1. Similar hardiness zones to those of Ontario throughout the company's region.
2. Exclusion of municipal utilities.
3. Combination of rural and remote customers must exceed 50%.

Ontario Energy Board (Board Staff) INTERROGATORY #15 List 1

Interrogatory

Ref: Exhibit D1 Tab 2 Schedule 1 – section 4.1.5 – Rights-of-Way Vegetation / Issue 4.3

a. Will the level of clearing of vegetation or allocation of funds and effort in this area continue after 2008?
b. Are there any environmentally acceptable and cost effective methods of economically retarding vegetative growth other than physical cutting?
c. What alternative methods has Hydro One investigated and what have been the findings of such investigations?

Response

a. Yes. Hydro One's analysis has indicated that a shorter cycle will result in benefits related to reliability and cost, as discussed in the response at Exhibit H Tab 1 Schedule 49 and Exhibit H Tab 6 Schedule 3, respectively. As a result, Hydro One is committed to maintaining funding for an 8-year cycle and will re-assess the benefits of moving to an even shorter cycle in the future.

b. Yes. Hydro One uses a variety of approved herbicides, application methods and site specific selective treatments as part of its integrated vegetation management practices. As alternatives to physical cutting, these practices are considered to be very cost effective and they encourage the establishment of compatible and diverse vegetation ground cover on rights of way. Whenever possible, Hydro One endeavors to use these alternatives, although the company has faced increasing pressure from municipalities and other groups resistant to herbicide use.

c. Hydro One has, and continues to, investigate alternative methods of vegetation management. This includes a wide range of herbicide products, product formulations, application methods, cover crops, grazing, natural products and biological controls. Specific examples include:
   i. New triclopyr formulations where the petroleum distillates have been replaced with plant derived products. Distillates are the products that contain the active ingredients. These new formulations have been found to be more acceptable from an environmental perspective.
   ii. The effectiveness of Glyphosate in areas of stump and stubble treatment is another area that the company is currently investigating. In some cases, we have found the public is more accepting of these products over more conventional applications.

Ontario Energy Board (Board Staff) INTERROGATORY #16 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 1 – Rudden Study / Issue 4.2
On pages 2 and 3, Hydro One states, "In accordance with the accepted Rudden recommendations on overhead capitalization rate, beginning in 2007 Hydro One Networks is adjusting the overhead capitalization rate within the year to reflect projected changes in spending. This will better align the overhead capitalization rate with overhead costs of the capital projects supported. This adjustment, called E-factor, true's-up the capitalized overheads by -$14.4 million. This is included as an adjustment to the derivation of the 2008 capitalization rate."

a. Please confirm if the above statements mean that, absent this adjustment, the capitalized overhead would have been that amount higher for Hydro One Distribution's capital expenditure.
b. Please provide further explanation on the basis for the adjustment and the derivation of the adjustment of $14.4 million for 2008.
c. Please describe the accounting treatment used to record the -$14.4 million and the reasons for its selection.
d. Please describe how the allocation of overhead to smart meter OM&A and to smart meter capital expenditures is supported by the Rudden Study.
e. Please show the dollar amounts and describe the methodology for allocating corporate overhead to smart meter OM&A and to smart meter capital expenditures in 2006, 2007 and 2008.

Response

a) Yes. The 2008 capitalized overhead would have been $14.4M higher for Hydro One Distribution's capital expenditures.

b) Based on the Rudden overhead capitalization rate methodology, a true-up of capitalized overheads should occur subsequent to the year end. This is done by calculating what Hydro One Distribution should have capitalized ($45.4 million) compared to the actual amount of overheads capitalized booked ($59.8 million). The fiscal 2006 result was that a true-up to overheads capitalized of $14.4 million is to be applied as an adjustment in 2008. This is consistent with the OEB accepted Rudden methodology filed under EB2005-0378, Exhibit C, Tab 6, Schedule 2, Attachment A.

c) Based on the Rudden overhead capitalization rate methodology, the E-Factor adjustment was included in the calculation of the 2008 overhead capitalization rate and will be applied consistently to all capital expenditures. The $14.4 million

adjustment lowered the overhead capitalization rate which in turn will reduce the overheads capitalized in capital expenditures in 2008. The corresponding lower overhead capitalized credit in OM&A (resulting in higher OM&A) in 2008 has not been sought for recovery in this application.

d) Overheads are not allocated to smart meter OM&A. Smart meter capital expenditures are included in the capital base, which forms part of the Rudden overhead capitalization rate methodology.

e) Overheads are not allocated to smart meter OM&A. The capital overhead rate is applied to smart meter capital expenditures consistent with the Rudden overhead capitalization rate methodology. The following table provides a summary of overheads applied to smart meter capital expenditures.

Capital Overheads in Smart Meter Capital

in $ million	2006	2007	2008
	Historical	Bridge	Test
Capital Overheads	2.1	6.7	13.3

Ontario Energy Board (Board Staff) INTERROGATORY #17 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – Customer Connection Forecasts/ Issue 4.4
In section 2.1.1, Hydro One states, "In 2005 and 2006 new connections averaged around 17,600 customers a year …It is estimated that about 17,600 new connections will be added to the Hydro One Distribution's system during 2008 which is in line with the recent historic average and validated by projected load forecasts. Exhibit [sic], Tab 14, Schedule 3 sets out the distribution load forecasting details and methodologies used."

a. What are the macroeconomic assumptions used in developing the forecast?
b. How are these different (type and magnitude) from those used to develop the 2005 and 2006 forecasts?
c. What was the forecast of new connections in 2005 and 2006?

Response

a. The macroeconomic assumptions used in developing the new connections forecast in 2007 are presented in the table below:

Macroeconomic Assumptions Used in Developing New Connections Forecast in 2007

Year	Ontario Housing Starts (thousands)	Growth in Ontario GDP in Constant $ (%)	Growth in Ontario Population (%)
2005 (Actual)	78	2.8	1.1
2006 (Actual)	74	13	1.0
2007 (Forecast)	67	1.7	1.2
2008 (Forecast)	68	2.9	1.2

b. The macroeconomic assumptions used to develop the new connections forecast in 2005 and 2006 are presented below:

Macroeconomic Assumptions Used to in Developing New connections Forecast in 2005 & 2006

Year	Ontario Housing Starts (thousands)	Growth in Ontario GDP in Constant $ (%)	Growth in Ontario Population (%)
2005 Forecast			
2005 (Forecast)	76	2.1	1.0
2006 (Forecast)	70	2.9	1.1
2007 (Forecast)	71	3.0	1.0
2008 (Forecast)	73	3.0	1.0
2006 Forecast			
2006 (Forecast)	75	2.5	1.1
2007 (Forecast)	70	2.5	1.0
2008 (Forecast)	74	3.0	1.0

c. The forecast of new connections made in 2005 and 2006 are presented in the table below:

Forecast of New Connections Prepared in 2005 and 2006

Year	2005 Forecast	2006 Forecast
2005 (Forecast)	17722	
2006 (Forecast)	17542	17339

Ontario Energy Board (Board Staff) INTERROGATORY #18 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 2 – Wood Structure Replacement/ Issue 4.3

a. Please explain how the proposed 2008 wood pole replacement program involving 7000 poles (which represents 0.42% of the 1.65M pole population) is an adequate level given that the asset condition assessment indicates that 4% of poles are in poor or very poor condition.
b. Please indicate how many poles of the 4% in the "poor" or "very poor" condition are being replaced under other projects such as Line Projects.

Response

a. As stated in Exhibit D1, Tab 2, Schedule 1, information used to assess the condition of wood poles and to identify poles that need to be replaced is gathered from pole assessments (i.e. inspections and tests). Wood pole assessment is a cyclical activity, as it is neither practical nor feasible to test all 1.65 million poles during any given year. Under the current plan for pole assessments, Hydro One will complete the assessments of all poles over a 6 year period, and expects to replace 7,000 to 10,000 poles each year over this period under the Pole Replacement Program. The number of poles planned for replacement each year depends on the testing program volumes of the previous years and the number found substandard. This being the case, the 4% should be compared to the percentage of poles replaced over a 6 year period rather than one year, as assumed in the interrogatory. The "very poor" to "poor" condition poles will be addressed over a 6 to 7 year period with the majority, about 40,000 to 50,000, being addressed under the pole replacement program. This approach to managing the condition of poles in the system is standard in the utility industry.

b. Once identified, the "Very Poor" poles are replaced in an expedient manner as part of the Lines Trouble Call Program. The "Poor" poles are replaced as part of planned programs with the vast majority being replaced by the Wood Pole Replacement Program. The 2008 Wood Pole Replacement Program will address those poles where a "one for one" replacement is appropriate, e.g., where there are no other plans for modifying the feeders or where a complete rebuild of a section of a feeder is not the preferred alternative. There are 7,000 poles planned for replacement during 2008 that fall into the "one for one" replacement category.

In addition to the Wood Pole Replacement Program and Trouble Call Program, poles are also replaced as part of a number of other activities such as Sustaining Lines Projects, Joint Use and Relocation Projects, and some System Capability Reinforcement Projects. The exact number of substandard poles that are replaced as

part of these programs is not tracked individually, but the "Poor" and "Very Poor" poles found during the pole assessments and not replaced under the Pole Replacement program will be replaced under these other programs and projects.

Ontario Energy Board (Board Staff) INTERROGATORY #19 List 1

Interrogatory

Ref: Exhibit D1 Tab 3; Schedule 3 – Development Capital/ Issue 4.4
On page 2, Hydro One states the following "The 2008 proposed spending is approximately 18% above historic [sic] averages, with the increase primarily attributed to:

- Additional system reinforcement spending to address the cumulative impact of increased utilization of the distribution system;
- Material and equipment cost increases above forecasted escalation. Since 2005, the electrical industry has experienced increases in material and equipment costs in the order of 20% to 40%;
- Increase in anticipated Distribution Generation connections to meet Government Programs;
- Change in new customer connection mix moving towards more high cost subdivision connections.
- Increase in volume of the more costly full Wholesale Revenue Meter conversions to comply with market rules."

a. With respect to material and equipment cost increases (referenced in bullet 2), please provide a table for major material and equipment categories showing the total dollar amount and number of units purchased for the period 2004 to 2008.
b With respect to the number of and change in type of new customer connections (referenced in bullet 4), please provide a table showing the annual number of new connections, total annual dollar amount, dollar amount attributed to Hydro One and dollar amount attributed to customers for the period 2004 to 2008.
c. With respect to Wholesale Revenue Meter conversions (referenced in bullet 5), please provide a table indicating the number and average cost of both partial and full wholesale meter upgrades or conversions by voltage level completed for the period 2004 to 2008. Please state why the program for Wholesale Meter conversions has increased in 2008.

Response

a. The table below contains the total dollar amount and the number of units purchased for major material and equipment categories attributed to Development Capital work.

Category	Measure	2004	2005	2006	2007	2004-2007
Distribution Transformers	Amount ($)	$11,197,775	$12,601,076	$11,452,347	$16,897,551	
	Quantity	7,649	8,685	7,273	7,805	
	Unit Cost ($)	$1,464	$1,451	$1,575	$2,165	
	% Increase		-1%	9%	37%	48%
Poles	Amount ($)	$1,661,386	$1,830,242	$1,755,628	$2,427,338	
	Quantity	5,374	5,623	4,389	5,703	
	Unit Cost ($)	$309	$325	$400	$426	
	% Increase		5%	23%	6%	38%
Conductors / Wires	Amount ($)	$1,324,945	$1,189,234	$1,476,997	$1,989,777	
	Quantity	921,552	790,675	686,361	916,378	
	Unit Cost ($)	$1.44	$1.50	$2.15	$2.17	
	% Increase		5%	43%	1%	51%
Power Line Hardware	Amount ($)	$1,085,497	$1,617,341	$1,549,502	$1,879,820	
	Quantity	107,504	113,092	89,821	108,944	
	Unit Cost ($)	$10	$14	$17	$17	
	% Increase		42%	21%	0%	71%

b. New Connections – Actual Volume and Cost History

	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Forecast 2008
New Connections (Annual Number)	17,959	18,320	17,110	18,023	17,583
Total Cost ($M)	73.0	78.7	84.4	88.2	84.4
OM&A and Removals ($M)	3.9	3.4	4.3	3.5	4.2
Net HONI Capital Cost ($)	69.1	75.3	80.1	84.6	80.2
Customer Contribution ($M)	23.8	21.1	17.3	17.2	18.6
Total Cost ($M)	96.8	99.8	101.7	105.4	103.0

c. Wholesale Revenue Meter Conversions

Year	Actual Units Completed	
	Partial Upgrade	Full Upgrade
2004	5	16
2005	9	28
2006	5	42
2007	2	40
2008	0	45

The unit costs are not readily available on a year by year basis, however analysis of costing data shows that the average cost for a Partial Upgrade has ranged from about $70,000 to $105,000 and a Full Upgrade cost has been in the order of $210,000 to $240,000.

The program for Wholesale Meter conversions has increased in 2008 to address an increase in meter conversions required to meet Measurement Canada requirements, as discussed in Exhibit D2, Tab 2, Schedule 3, IJD D16.

Ontario Energy Board (Board Staff) INTERROGATORY #20 List 1

Interrogatory

20. Ref: Exhibit D1 Tab3 Schedule 3 – section 2.1.4 – Service Cancellations/ Issue 4.4
    a. Please provide the actual and forecasted costs for service cancellations for each year from 2004 to 2008.
    b. Please clarify whether these service cancellation costs are to be capitalized or expensed.

Response

a.

Actual & Forecasted Service Cancellation Costs - $ millions

	2004	2005	2006	2007	2008
Actual	3.5	3.2	3.5	3.4	
Forecast	3.6	3.5	4.0	3.2	3.4

b. Service cancellation costs are current period expenses classified within depreciation expense.

Ontario Energy Board (Board Staff) INTERROGATORY #21 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – Reliability Enhancement and System Monitoring Projects/ Issue 4.2

Hydro One provides a summary of system monitoring projects on page 10, lines 1 to 7. Please indicate the number of monitoring locations established and the total dollar amount for the period 2004 to 2008.

Response

Between 2004 and 2007 Hydro One did not install monitoring at distribution stations.

During 2008 Hydro Plans to spend $0.9 million for monitoring at 9 stations.

Ontario Energy Board (Board Staff) INTERROGATORY #22 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – Generation Connection/ Issue 4.2

Please indicate who (i.e. Hydro One, the generator) pays for the connection assessments and cost estimates.

Response

As stated in Exhibit D1, Tab 3, Schedule 3, Section 2.3 (Generation Connections) "Generation developers are normally responsible for all connection costs".

Consistent with this, connection assessments are paid for by the generator through a fee. This fee is currently $3,000 for projects up to 1 MW, $5,000 for projects over 1 MW and up to 10 MW, and $6,000 for projects larger than 10 MW.

Connection estimates are also paid for by the generator. Generators pay the actual cost of preparing estimates rather than a fee because of the variability in the work required to do the estimates driven by the differences between the connection requirements for the various projects.

Ontario Energy Board (Board Staff) INTERROGATORY #23 List1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – Generation Connection/ Issue 4.2
On page 12 of 18, Hydro One states, "Upgrades to Hydro One's distribution lines (poles in particular) may also be required in cases where the customer chooses to make use of Hydro One facilities rather than build their own. Based on Hydro One's experience with joint use, it is anticipated that in these situations, Hydro One will be accountable for 83% of the upgrade costs and the customer will contribute 17%. Provision for the associated costs is included in this filing and results in net costs of $4.4 million in 2008."

Please explain the basis for recovering 83% of pole upgrade costs from ratepayers, when a pole upgrade is necessary where a new generation customer decides to make use of Hydro One pole facilities under joint use.

Response

In most cases where a line route selected by a proponent extends along a section of road that is occupied by a Hydro One line, rights of way are not available for both lines to exist for an extended distance. Under these conditions, Hydro One's approach will be to offer to share the right of way and structures with the proponent. If agreeable, the proponent will be required to pay for new assets and donate them to Hydro One as replacements for existing rural lines. The proponent will be credited for the donation of assets related to the existing line and this credit will be used to offset: (1) the residual value of the existing line (2) future maintenance costs and (3) Hydro One's costs to upgrade the line (i.e. transfer existing circuits onto new structures). In cases where the credit will not fully offset Hydro One's incremental costs on a present value basis, the proponent will be required to make a capital contribution such that Hydro One is held harmless.

Based on limited experience to date with line upgrades driven by generation connections, the proponent's contribution has averaged about 17% of the upgrade costs. Hydro One recognizes that there is uncertainty surrounding this value given the limited history, the potential variability between projects, and the fact that the number of projects that will actually go forward is something totally controlled by proponents, not by Hydro One.

Ontario Energy Board (Board Staff) INTERROGATORY #24 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – Generation Connection/ Issue 4.2
On page 13 of 18, Hydro One states, "Power quality (PQ) impacts on Hydro One's distribution system and customers is a key issue associated with certain types of generators (such as wind). To ensure this is appropriately understood and managed, Hydro One Distribution is installing PQ meters in the vicinity of possible wind generation connections to enable monitoring of customer PQ issues in these areas. The associated capital is not covered by contributions from generators and amounts to $1.2 million in net costs in 2008."

a. Please provide the derivation of the $1.2 million cost estimate for PQ Metering.
b. Please explain what is meant by in the vicinity of "possible" wind generation connections. Are these locations where a SOP project has been initiated?
c. Please explain, absent an actual wind generation connection, the benefit of the PQ meter to Hydro One ratepayers.
d. Please explain why costs of PQ meter installations are not being recovered through contributions from generators.

Response

a. The installed cost for a PQ meter at one location is estimated at about $50K. Hydro One plans to install PQ meters at 25 locations (stations) at a total cost of $1.2M.

b. "In the vicinity of possible wind generation connections" would be at Hydro One transformer stations with feeders where wind generation is expected to be connected in the near future. These transformer stations would be connected to locations where SOP projects are being considered (i.e. at study stage or beyond).

c. With increasing sensitivity of connected customer systems to the quality of power supply, it is prudent for Hydro One to monitor the quality of supply and work with customers to address any PQ related issues. PQ monitoring is analogous to other monitoring devices installed on the system (such as voltage and current) for system benefit as well as for the benefit of all load and generation customers. In addition, PQ monitors assist in the identification and resolution of PQ issues should these issues surface on the distribution system whether these issues are triggered by the system or a customer.

Hydro One has in place a Power Quality Monitoring program to ensure quality of supply to load customers, where PQ monitors are normally installed at transformer stations supplying load customers at the LV level. PQ concerns are heightened by

our lack of operating experience with wind generation technologies. In order to assess the PQ impact on the distribution system and customers once wind generators are connected, it is important to establish "baseline" levels of information by installing PQ monitors in advance of connecting these wind generators. This baseline monitoring benefits all customers by allowing Hydro One to determine the root causes of any future PQ problems.

d. See answer to part c) above.

Ontario Energy Board (Board Staff) INTERROGATORY #25 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – section 2.3 – Generation Connection/ Issue 4.2

Table 3 indicates that only 20 small, 40 medium and 4 large generator connections are expected to proceed to completion.

Response

Yes, that is correct.

Ontario Energy Board (Board Staff) INTERROGATORY #26 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – Generation Connection/ Issue 4.2
Please provide the detailed calculation of and principles for the allocation of costs of connection, between Hydro One and generation developers including:

a. The basis for determining the cost allocation percentage between Hydro One and generation developers for connection costs. (30% for connection of generators in the large category, 25% for mid-size projects and 15% for small generators.);
b. The calculation of the estimated $2.8 million connection costs;
c. The calculation to show the derivation of the $4.4 million distribution line cost.

Response

a. These allocations are based on historical data and the connection impact assessments carried out to date. As the number or capacity of new generators connecting to a feeder or overall at a TS increases, the likelihood of later projects requiring upgrades in order to integrate them into the distribution system increases. In cases where these upgrades also benefit the Hydro One system and other distribution customers, Hydro One will contribute a portion of the upgrade costs consistent with that benefit. The likelihood of a benefit to the system and other customers generally increases depending on the size of the connecting generator, since larger generators are more likely to require extensive upgrades to facilities used by others.

   As well, if Hydro One needs to advance an upgrade already in the plan to accommodate the needs of a new generator, that generator would only bear the advancement cost related to the upgrade. Based on the experience to date, it is anticipated that Hydro One contribution for upgrades would be 30% in the large generator category, 25% in the mid-size category, and 15% in the small generator category.

b. The estimate of $2.8M is the cumulative sum of the connection costs in each of the large, mid and small category of generation projects. Unit costs for specific pieces of work in distribution lines and stations categories were established for each generator size and these unit costs were then multiplied by the forecasted connections in each category (4 large, 40 mid and 20 small) and by the % forecast to be paid by Hydro One (per part a above). The detailed results are shown below:

Category	Expected # of Connections	Work Unit	Unit Cost ($M/connection)	Total Cost ($M)	Hydro One Cost ($M)
Large-Size	4	Station	0.200	0.8	0.4
		Lines	0.100	0.4	
		Customer Contribution	0.200	0.8	
Mid-Size	40	Station	0.133	5.32	2.1
		Lines	0.070	2.8	
		Customer Contribution	0.150	6.0	
Small-Size	20	Station	0.070	1.4	0.3
		Lines	0.033	0.7	
		Customer Contribution	0.090	1.8	
Total	64				2.8

c. Refer to interrogatory response in Exhibit H, Tab 1, Schedule 23.

Ontario Energy Board (Board Staff) INTERROGATORY #27 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 3 – section 2.5.4 – Central Metering/ Issue 4.2 Hydro One provides the following table showing the volumes of central metering requests:

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Central Metering	1,095	1,095	1,095	950	950

a. Please identify if the 2004, 2005 and 2006 volumes are actuals or approximations;
b. Please explain the decrease for the number of central metering requests in the 2007 bridge and 2008 test years;
c. Please provide a disaggregation, if possible, of central metering requests < 45 kW and ≥ 45 kW.

Response

a. The volumes identified for 2004, 2005 and 2006 are approximations.

b. Hydro One's estimate of the number of central metering requests in 2007 bridge and 2008 test years shows a decrease because we have noted a trend in customer connections towards smaller properties such as those in subdivisions, which do not have additional outbuildings on the property that require centralized services.

c. An estimate of the disaggregation of central metering of services would be 85% for under 45 kW and 15% for 45 kW and higher.

Ontario Energy Board (Board Staff) INTERROGATORY #28 List 1

Interrogatory

Ref: Exhibit D1 / Tab 3 / Schedule 3, section 2.5.6 – Temporary Services/ Issue 4.2
Hydro One provides the following table showing the volume of temporary services provisions by year:

	2004 volume	2005 volume	2006 volume	2007 volume	2008 volume
Temporary Services	211	211	211	211	211

Please identify if the 2004, 2005 and 2006 volumes are actuals or estimates.

Response

The volumes shown for 2004, 2005 and 2006 are estimates

Ontario Energy Board (Board Staff) INTERROGATORY #29 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 5 – Shared Services/ Issue 4.7

a. Please describe the methodology underlying the allocated split of capital to Shared services and Other Capital between Hydro One Distribution and Hydro One transmission;
b. Please provide a numerical example of the methodology as applied to one major component of Shared Services.

Response

a. The methodology underlying the common asset allocation is described in Exhibit C1, Tab 5, Schedule 3. The Rudden study was accepted as a reasonable representation of the use of shared assets amongst the business units by the company. This methodology was endorsed by the Board in the 2006 Distribution rate decision (in RP-2005-0020/EB-2005-0378).

b. In Exhibit D1, Tab 3, Schedule 5, page 2, Table 2 the Transport & Work Equipment total Shared Services Capital Expenditure is $51.6M. The Rudden study filed in RP-2005-0020/EB-2005-0378 shows the Distribution portion to be 76%, therefore the $51.6M X 76% = $39.2M.

Ontario Energy Board (Board Staff) INTERROGATORY #30 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 5 – Information Technology/ Issue 4.2

a. Please describe the differences and the relationship between the following IT projects: Customer Information System (CIS), Customer Relationship Management (CRM) and Phase 4 of the Cornerstone project.
b. Please provide a diagram which shows how the various computer systems covered by this $200 million investment, interface with, and relate to each other, clearly marking those substantially completed in 2007 and those scheduled for completion in 2008, with budgeted costs in those years.
c. Please describe the meaning of "virtualization of the Storage Area Network" described on page 9, line 25.

Response

a. The CIS and CRM projects are described in Exhibit D1, Tab 3, Schedule 5 at 2.4.2. The CIS Hybrid program is intended to improve the business performance and system reliability with the existing Customer 1 platform and open market systems prior to their replacement in Phase 4 of Cornerstone. These systems are used by Customer Care, Field Services Operations and for the billing of distribution customers. The CRM system is intended for large distribution customers and transmission system customers. Phase 4 is intended to replace the existing Customer 1 system and Open Market System.

b. The total capital cost for these unrelated projects is $128.7 million. The total project costs as shown in Table 6 for Cornerstone amount to $123.4 million and the CIS/CSS Hybrid upgrade and the CRM project amount to $5.3 million and are budgeted to be spent as indicated. Cornerstone Phase 1 is projected to be completed in 2008.

c. Virtualization of the storage network refers to the management and manipulation of the data storage devices and data. Hydro One has commenced a program to better manage its data and storage area devices. In 2007 Hydro One changed its data storage model by purchasing data storage services and storage space on a shared services basis from Inergi rather than purchasing its own equipment. To accommodate this change Hydro One purchased certain software applications to allow for the maintenance and security of the data stored on the Inergi shared storage devices.

Ontario Energy Board (Board Staff) INTERROGATORY #31 List 1

Interrogatory

Ref: Exhibit D1 Tab 4 Schedule 1 – AFUDC/ Issue 4.1

a. Please confirm that Construction Work in Progress, for facilities not brought into service in test year 2008, is not included in the 2008 rate base. If that is not the case, please explain the accounting treatment of Construction Work In Progress.
b. Please confirm that those projects that have been brought into service in 2007, and budgeted for 2008 have the AFUDC included in the actual costs and estimated costs for inclusion in the 2008 rate base.

Response

a. Construction Work in Progress for facilities not brought into service in test year 2008 is not included in the 2008 rate base.

b. Those projects that have been brought into service in 2007 and budgeted for 2008 have the AFUDC included in the actual costs and estimated costs for inclusion in the 2008 rate base.

Ontario Energy Board (Board Staff) INTERROGATORY #32 List 1

Interrogatory

32. Ref: Exhibit D1 / Tab 3 / Schedule 5 – Service Equipment/ Issue 4.2
Minor fixed assets ("MFA") service equipment expenditure is increased by 138% from 2006 ($3.9 million) to 2008 ($9.3 million). On page 36 of 39, Hydro One states, "Higher year over year spending in 2007 & 2008 is the result of end-oflife replacement of specific large transport equipment and to accommodate planned growth in distribution and transmission work program."

a. Please elaborate on the "planned growth in distribution and transmission work program" and describe it in detail including the period covered. Please provide the breakdown of the growth and costs for the distribution business that require these work programs.
b. If both "end-of-life replacement of specific large transport equipment" and "planned growth in distribution and transmission work program" are the contributing factors to this significant increase, please describe the percentage contribution to this increase for each of these cost determinants for the distribution business.

Response

a) The majority of the requested spending in 2008 is for end of life and normal replacement. The planned growth in distribution and transmission work is primarily related to improving performance through an expanded forestry program (such as line clearing and brush control) and lines sustainment programs and work done by Engineering and Construction Services (to support the IPSP plan) to ensure the safe and reliable operation of the distribution system. The Minor Fixed Assets expenditures requested are used by Hydro One Networks crews in their day to day operations.

Approximately 20% of the $5.4 million increase between 2006 and 2008 in Minor Fixed Assets relates to this planned growth in distribution and transmission work programs. 2008 examples include expenditures for Pullers and Tensioners for lines and Automated External Defibrillators (AED).

b) From 2006 to 2008, out of the total increase of $5.4M ($9.3M - $3.9M), approximately 75% is due to the end of life replacement of major transport equipment, 5% is attributable to normal replacement and approximately 20% is attributable to the increased construction and maintenance work programs, and measuring and testing equipment to support work crews in day-to-day field operations.

Ontario Energy Board (OEB Staff) INTERROGATORY H-1-33

Interrogatory

Reference: Exhibit D1 Tab 3 Schedule 5 – IT Capital Expenditure, Table 3/ Issue 4.2

The capital expenditure for development projects increased by 426% from 2006 ($12.5 million) to 2007 ($65.8 million) and by 449% in 2008 ($68.6 million) compared to 2006. On page 6, Hydro One states "Deployment projects replace or upgrade older and end-of-life applications or develop new applications or processes, including those:

- o that have become inadequate for current functional needs;
- o that require new applications to improve Business operations
- o that result from legislative or market driven initiatives".

a. Please provide a table showing the amounts for the above three categories for each year from 2006 to 2008, summing to the Development Projects capital expenditures shown in Table 3. Please outline the implementation duration (start date, end date) for each development project.
b. Please explain if Hydro One has considered a phased approach for any of the Development projects in order to spread the implementation costs over a larger number of years and thus reduce the impacts on rate payers. If Hydro One does not consider a phased approach to be appropriate, please provide an explanation.

Response

a. A breakdown of the projects is provided in Exhibit D1 Tab 3 Schedule 5 Table 6. Adjusting for the Cornerstone project the Non Cornerstone spend from 2006 to 2008 is as follows:

	2006	2007	2008
Non Cornerstone related Development Project Capital ($ millions)	12.5	5.4	5.6

The increase in spending in Table 3 is related to the Cornerstone project and is partially offset by a decline in other development spending. Adjusting for Cornerstone spending on IT, Development project spending declines in comparison to 2006.

The project start date is the year that expenditures began to be incurred; and the project end date is the year in which the final expenditure is shown. For example,

the CTI project started in 2005 and ended in 2007. None of the projects shown extend into 2009, except the Cornerstone Project (note that Cornerstone Phase I does end in 2008).

	Inadequate	**Improve**	**Legislated**	**Total**
2006				
CIS	0.4			0.4
ACPi		8.0		8.0
CTI	3.3			3.3
Asset data			0.8	0.8
				12.5
2007				
CIS	2.7			2.7
CRM	0.2			0.2
ACPi		0.9		0.9
CTI	0.7			0.7
Asset data			0.9	0.9
				5.4
2008				
CIS	2.0			2.0
IREIS		0.3		0.3
Mobile IT		3.0		3.0
Asset Information		0.3		0.3
				5.6

b. Hydro One considers a phased approach for all development projects. ACPi/WEP was undertaken in a phased approach with ACPi phase delivered in advance of the WEP application. CTI also had a phased process as does Cornerstone which is a phased system replacement program.

Ontario Energy Board (Board Staff) INTERROGATORY #34 List 1

Interrogatory

Ref: Exhibit D2 Tab 2 Schedule 3 Reference # S11 – Havelock TS 57M1
Feeder Refurbishment/ Issue 4.3
Please provide the Board approved Capex budgeted and the actual expenditures from 2004 to 2007 (cumulative) for the 20 kilometres of line section between Eels Lake RS and Bancroft DS. Please explain any significant variance (difference between budgeted and actual > 10%) in the costs incurred to date on this project.

Response

This project was included in the overall 2006 capital budget approved by the Board as part of Hydro One Distribution's 2006 Rates Application, but capital spending for this project was not specifically identified in the Application. Actual expenditures are as noted below. There was no Board approved capital budget for 2004 and 2005.

Cumulative Expenditures from 2004 to 2007

	2004 ($M)	2005 ($M)	2006 ($M)	2007 ($M)
Actual	0.5	1.1	1.5	5.7

Ontario Energy Board (Board Staff) INTERROGATORY #35 List 1

Interrogatory

Ref: Exhibit D2 Tab 2 Schedule 3 Reference #S17 – Fort Frances TS M1 Feeder Rehab Phase 3/ Issue 4.3
Please provide the Board-approved capex budgeted and the actual expenditures for the first two years (cumulative) of this project. Please explain any significant variance (difference between budgeted and actual > 10%) in the costs incurred to date on this project. When is this project expected to be completed and operational?

Response

This project was included in the overall 2006 capital budget approved by the Board as part of Hydro One Distribution's 2006 Rates Application. The specific capital amount for 2006 provided in the Application, as well as the cumulative costs for the first two phases of project, are provided below:

	2006 ($M)	2007 ($M)
2006 Application	0.6	*
Actual	0.5	0.9

* There is no Board approved capital budget for 2007.

This project is scheduled to be complete by 2011. The line is operational throughout the two phases, except when outages are required to complete the work.

Ontario Energy Board (Board Staff) INTERROGATORY #361 List 1

Interrogatory

Ref: Exhibit D2; Tab 2; Sched. 3 Reference # S18 – Metering for Shared Use Distribution Charges/ Issue 4.2

a. Please explain the rationale for installing new meters at 20 sites.
b. Please indicate the number of sites where new meters were installed in each of the historic years 2004 to 2007 and the corresponding costs.

Response

a) The Ontario Energy Board instructed Hydro One during October 2002 to implement Low Voltage Facilities Charges. This charge is applied to a Local Distribution Company (LDC) for the benefit of shared use of a Hydro One owned distribution station. Shortly after this, rates were frozen until May 2006 as a result of Bill 210. The initial system review of meter installations carried out during 2006 identified about 100 locations on the system required meter upgrades or additions in order to bill customers for the Low Voltage Facilities Charge. In order to adequately assess each location and complete the work in an organized and manageable time frame, it was decided to implement a program for meter installations that would span a period of 5 years. The first year of the program was in 2007. The 2008 rate filing is based on 20 meter installations at $0.1 million per site for a total projected cost of $2 million.

b) 2007 was the first year of this program and 4 installations were completed at a total cost of $0.3 million.

Ontario Energy Board (Board Staff) INTERROGATORY #37 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 5 and Exhibit D2 Tab 2 Schedule 3 reference #IT1 – Cornerstone Project/ Issue 4.2

In Table 6 on page 15, Hydro One Distribution is allocated $28 million (from the total of $63 million) for the Cornerstone project for the 2008 test year.

a. Please provide details of the basis for the cost allocation to Hydro One Distribution for the Cornerstone project.

b. Table 6 shows a Cornerstone Project related 2008 expenditure of $63.0 M while Exhibit D2 Tab 2 Schedule 3 Reference # IT1 shows Cornerstone 2008 expenditure as $50.3 million. Please provide a reconciliation of these figures.

c. The table at the bottom of Exhibit D2 Tab 2 Schedule 3 reference # IT1 shows Capital and MFA expenditures of $76.7M for 2007 and $50.3M for 2008 test year. Please provide the cost breakdown between Hydro One Transmission and Distribution for each of these years.

Response

a. Cornerstone Phase I costs were allocated between Transmission and Distribution following the shared services and cost allocation approach. On this basis, Cornerstone Phase I costs were allocated to Distribution as follows:

Capital	44%
OM&A	44%
MFA	57%

b. The 2008 value of $50.3 million in D2 Tab 2 Schedule 3 Reference # IT1 reflects Cornerstone Phase I capital and MFA expenditures; the Cornerstone Project value of $63.0 million in Table 6 of Exhibit D1 Tab 3 Schedule 5 includes $50.3 million for Phase I and 2008 costs for Phases II and III.

c. The capital and MFA cost breakdown for Hydro One Transmission and Distribution for 2007 and 2008 is:

Cornerstone Phase I	**2007**	**2008**
Hydro One Transmission	$43.0 M	$28.0 M
Hydro One Distribution	$33.7 M	$22.3 M
Total	**$76.7 M**	**$50.3 M**

Ontario Energy Board (Board Staff) INTERROGATORY #38 List 1

Interrogatory

Ref: Ref: Exhibit C1 Tab 4 Schedule 2 – Implementation of Cornerstone Phase I /Issue 4.2
In this Exhibit, at page 11, lines 7-11: Hydro One states, "Implementation of Cornerstone Phase I, as discussed in detail in Exhibit D, Tab 3, Schedule 5 is anticipated to contribute productivity gains through its lifetime for total cost efficiency gains equal to about $200 million commutative over the seven year lifetime of the new IT systems beginning in 2009".

a. Please confirm if Cornerstone Phase I will be in service in 2008.

b. Please confirm if Hydro One assumes that the cost efficiency gain as a result of Cornerstone will not be realized in 2008.

c. Please state the nature of cost efficiency gains equal to about $200 million as referenced in the above quote, and provide detailed descriptions of areas of cost savings and the expected associated cost savings expressed in dollars.

d. With respect to the expected $35.0 million benefit arising from improved contract compliance and management documented on Exhibit D1 Tab 3 Schedule 5, page 21, please provide the detailed calculation of this estimated benefit.

e. Please state how Hydro One intends to capture the cost savings during the IRM process of 2009 and 2020.

Response

a. Yes, Cornerstone Phase I is expected to be in service for 2008, as planned.

b. Yes, cost efficiency gains for Cornerstone Phase I will not be realized in 2008.

c. The cost efficiency gains equal to about $200 million represent a stretch target at the upper end of the range of identified potential cost efficiency gains for Cornerstone Phase I. The $200 million stretch target is an imprecise figure, more akin to a ballpark. As such, the estimates of potential cost efficiency gains for the 12 individual benefit areas which follows, should not be regarded as precise, hard targets. Detailed descriptions of these 12 individual benefit areas follow, along with associated cost savings expressed in dollars.

1. Improve planning of materials and resources

The benefit area enhances work crew productivity due to better materials availability through more efficient forecasting, planning and execution. The contribution to improvement in crew productivity results from having the right materials available at the right time and the right location. This is enabled by developing a materials classification scheme, providing differentiated service levels, decreasing lead-time violations and increasing order fill rate. In addition, this benefit provides for better coordination and integration between the Lines of Business (LOBs) and Supply Chain. The resultant productivity gains will enable field crews to increase work throughput.

Expected Cost Savings (2009-2015): $35.5 M

2. Optimize O&M and Capital Asset Investments

This benefit area will optimize O&M / Capital asset investments through enhanced asset analysis and maintenance by managing operational risks over the asset life cycle. SAP core functionality will provide, for the first time, a real-time defect management system, financial and technical reporting capabilities at the asset level to facilitate O&M / Capital tradeoffs for optimizing asset life cycle and improving decision making for all assets. This will allow planners to optimize asset useful service life.

Expected Cost Savings (2009-2015): $50.3 M

3. Leverage Technology and Information Systems

This benefit area will provide more accessible information from Electronic Asset Management systems through better leverage of IT to achieve efficiency improvement in search and reconciliation work activities. The implementation of integrated tools and processes that span business processes and provide transparency and access to consistent data that can be viewed by appropriate staff in functional groups is expected to reduce the amount of time staff spend searching and reconciling data.

Expected Cost Savings (2009-2015): $19.9 M

4. Improve Internal & Supplier Contract Compliance

The nature of the efficiency gains in this area is improved contract compliance and management through reduction in non – Purchase Order spend for direct purchase of materials and services. This benefit is derived from all users purchasing standardized materials and services off negotiated contracts at agreed prices and terms. The ability to

more effectively monitor supplier contract compliance will improve as more expenditures are recorded against contracts for future analysis.

Expected Cost Savings (2009-2015): $ 35.0 M

5. Improve System Reliability through higher quality Asset Data

This benefit area will provide improved system reliability through higher quality asset data and avoided emergency work. In this benefit area, Hydro One will create a single high quality asset registry with correct hierarchies which will improve reliability by proactively identifying and managing the correction of defects before they become emergency trouble work. This should also reduce safety incidents and increase customer satisfaction via fewer unplanned outages.

Expected Cost Savings (2009-2015): $21.6 M

6. Better work planning and bundling

The nature of efficiency gains in this area is to bundle work for routine inspections and Preventive Maintenance work. In this area, Hydro One will achieve further improvements in having the right work identified at the right time for the right people. Hydro One will see results in reduced commuting time, better flexibility to address contingencies, and reducing wait time. Other work tasks will be made available to fill in some down time or delay time. Also, there will be reduced computer time for field staff in some LOBs. This includes not only maintenance but also project work for all staff for whom work will be planned, scheduled, and visible in the system.

Expected Cost Savings (2009-2015): $ 6.3 M

7. Increase back-office productivity Planner / Designer / Clerical

The expected efficiency gain in this area is improved back-office productivity through the reduced costs of tracking work to be scheduled and the time prioritizing work. This benefit is realized in the people and processes involved with planning, scheduling, tracking, and reporting work that has been awarded - typically in the 0-12 month range. New processes and tools will facilitate the tracking, management, planning and visibility of all work. Many current manual processes and rework will be eliminated.

Expected Cost Savings (2009-2015): $ 12.2 M

8. Improve Inventory Performance

The nature of the efficiency gain in this area is improved inventory performance through reduced expediting, material handling, storage costs, returns and excess/obsolete inventory. This benefit area provides a reduction in material inventory, due to a decrease in material returns and excess/obsolete inventory. It also captures the reduced expediting, material handling and storage costs, due to this decrease. This benefit is enabled by a centralized planning process, key capabilities like forecasting, inventory planning and materials management, and by better network deployment of materials within the Hydro One network.

Expected Cost Savings (2009-2015): $ 9.5 M

9. Improve warehouse shipping processes and payment reconciliation with carrier

The nature of the efficiency gains in this area are automated generation of shipping documents within SAP that will lead to better traceability of shipment invoices to shipments planned by Hydro One. It will allow the reconciliation of the carrier invoice with the actual shipment requested.

Expected Cost Savings (2009-2015): $1.6 M

10. Improve Electronic Receipt Settlement (ERS) processes

This area will increase the number of ERS vendors to reduce the number of manual invoices, transaction costs, reconciliation issues and cycle time associated with payments. This is SAP generating an invoice document upon receipt of goods or services through a batch program which will be selected for payment as its payment terms are applied.

Expected Cost Savings (2009-2015): $7.5 M

11. Greater control governance around one-time setup vs. regular AP vendor setup

The nature of efficiency gains in this area is the reduction in the number of one time vendors and cheque requisitions. The majority of vendors should be set up with a purchase order leaving only a small number of vendors with just invoices. Greater visibility of spend and therefore ability to analyze spend - both in terms of who's spending and where they're spending (vendors, types of services/materials etc) will result in improved Bill 198 and audit compliance and reduced impact on AP work effort for ad-hoc requests.

Expected Cost Savings (2009-2015): $0.6 M

12. Improve large Transmission customer satisfaction

The nature of the efficiency gains for this area is the improvement of the satisfaction of Hydro One's large transmission customers through more detailed reporting and improved connection process. For this benefit area, Hydro One expects to improve large transmission customer satisfaction by providing project management transparency, workflow capability & work management status reporting associated with new customer projects/connections. The basis for this improvement is twofold: 1) improving performance of meeting customer commitments, and 2) providing better, more effective response to Customer Project inquiries.

Expected Cost Savings (2009-2015): Intangible

d. With respect to the expected $35.0 million benefit arising from improved contract compliance and management, Hydro One's detailed calculation of this estimated benefit began with a forecast of Procurement Card (P-Card) and Non-Purchase Order (PO) / Non –P-Card purchases for direct purchase of materials and services.

   With the full use of contracts/contract functionality in SAP (ex. auto-applied discounts, quotas, payment terms, etc), it is expected that a significant percentage (up to 68%) of these purchases will be converted to PO based procurement. For those purchases that would have been P-Card purchase, this means that Hydro One will lose the small P-card discount but will gain in savings the higher discount and avoidance of premiums by buying on contract. For those purchases that would have been Non PO or Non P-Card purchases, the conversion to PO based procurement will produce savings through the discount and avoidance of premiums by buying on contract. By applying these determinants of savings, that are slightly offset by administrative and compliance monitoring costs for moving these purchases to a PO based procurement system, Hydro One forecasts savings in this area of $35 million.

e. During the 2009 and 2010 period, Hydro One anticipates that it will incur additional costs undertaking Phase 2 and Phase 3 of Cornerstone. Initially, the additional Cornerstone costs incurred in during this period will exceed potential savings from the Phase 1 initiative.

   Hydro One assumes any savings beyond 2008, specifically for 2009 and 2010, will be captured under the Board's approved 3rd Generation IRM.

Ontario Energy Board (Board Staff) INTERROGATORY #39 List 1

Interrogatory

Ref: Exhibit D1/ Tab 3/ Schedule 5/ Page 29 – Real Estate Capex/ Issue 4.2
In Table 7, Hydro One Distribution is allocated $4.0 million (from the total of $9.2 million) for the Real Estate major capital program.

Please explain the basis of the cost allocation to Hydro One Distribution.

Response

The Common Asset Allocation in Exhibit C1 Tab 5 Schedule 3 Table 1 shows the Shared Assets percentage as Tx 39.0% and Dx 61.0%. This combines common asset types (Major Assets, Minor Fixed Assets and Transportation & Work Equipment). The Real Estate major capital program is part of the Major Assets. The basis of the Real Estate Capital allocation is the portion of common buildings used by Distribution and Transmission operations as identified in the Rudden Study.

Ontario Energy Board (Board Staff) INTERROGATORY #40 List 1

Interrogatory

Ref: Exhibit D2 Tab 2 Schedule 1 – Comparison of Capital Expenditures – Historical, Bridge and Test Years/ Issue 4.2

Please provide a revised table showing an additional column with the 2006 Board-approved amounts.

Response

COMPARISON OF CAPITAL EXPENDITURES – HISTORIC, BRIDGE AND TEST YEARS

	2004	2005	2006 Board Approved	2006	2007	2008
Distribution Capital ($ millions)						
Sustaining						
Lines Capital						
Trouble Call and Storm Damage	38.3	51.7	41.7	90.6	51.7	53.4
Joint Use & Line Relocations	19.2	22.0	18.8	24.0	27.1	23.7
Line Asset Replacement	35.2	33.2	49.8	47.5	60.0	62.4
Total Lines Capital	92.7	106.9	110.3	162.1	138.8	139.5
Stations Capital						
Spare Transformers	4.8	1.7	1.1	2.8	0.6	3.5
Mobile Unit Substation Refurbishment	1.1	0.4	0.6	1.0	0.3	1.5
Station Refurbishment & Component Replacement	5.1	7.0	6.2	4.7	6.8	5.3
Total Stations Capital	11.0	9.1	7.9	8.5	7.7	10.3
Metering Capital						

Retail Meter Replacement	1.2	1.4	1.4	1.6	0.4	2.5
Smart Meters				14.1	76.7	164.8
Total Metering Capital	1.2	1.4	1.4	15.7	77.1	167.3
Total "Sustaining"	104.9	117.4	119.6	186.3	223.6	317.1
Development						
New Customer Connections & Upgrades	94.2	100.3	90.6	104.6	105.9	103.9
Distribution Generation Connection	0.0	0.3	1.3	1.5	1.8	8.4
Wholesale Revenue Meters	6.8	8.7	9.1	11.1	9.7	11.4
System Capability Reinforcement	37.7	32.4	36.2	29.7	36.9	44.0
Total "Development"	138.7	141.7	137.2	146.9	154.2	167.7
Operations	6.3	4.7	3.5	2.1	2.0	3.6
Transport and Work, and Service Equipment	12.0	32.1	34.3	33.6	35.7	44.5
Information Technology Capital	10.6	19.5	29.5	19.3	46.7	43.3
Facilities Capital	2.8	1.8	3.2	2.1	6.4	4.4
Other	(3.2)	0.1	5.7	2.4	8.0	(14.4)
Total Distribution Capital	**272.0**	**317.2**	**333.0**	**392.6**	**476.6**	**566.2**

Ontario Energy Board (Board Staff) INTERROGATORY #41 List 1

Interrogatory

Ref: Exhibit C2 Tab 5 Schedule 1 – Depreciation & Amortization Expense/Issue 3.7 and 4.2

a. Please provide a detailed description of the Other Regulatory Amortization and a detailed calculation of the amount of $43.4 million for 2007.

b. Please explain the reason for the Other Regulatory Amortization category to reduce to $0 in 2008.

c. What useful lives for depreciation purposes has Hydro One assumed for each of the types of assets used and/ or installed as part of the smart meter minimum functionality and excess functionality? For example, smart meter heads, radio frequency amplifiers, antennas, repeaters, other communication equipment, and Capgemini contract costs.

d. What amortization period has Hydro One estimated for computer system software and computer hardware related to the smart metering initiatives?

e. Please provide a table that shows the depreciation expense related to smart meters for 2006, 2007 and 2008.

Response

a. Other Regulatory Amortization for 2007 is the amortization of the Board approved Regulatory Asset Recovery Account - Phase 1 ($20.0M) and Regulatory Asset Recovery Account - Phase 2 ($23.4M), as described in Exhibit F1, Tab 1, Schedule 1, Sections 2.7.2 and 2.7.3.

b. Hydro One Distribution did not include the amortization of the Regulatory Asset Recovery Accounts in base revenue requirement for 2008 as these amounts are being recovered through rate riders.

c. Hydro One Distribution has assumed a depreciation life of 15 years for smart meters.

d. Hydro One Distribution has assumed an amortization rate of approximately 10% for computer software and 20% for computer hardware.

e. The estimated depreciation expense related to smart meters is shown in the response to Exhibit H, Tab 1, Schedule 120, part “a”.

Ontario Energy Board (Board Staff) INTERROGATORY #42 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 5 – Information Technology/ Issue 4.2
Under section 2.4 – IT Development Projects Capital Expenditures, Hydro One states that the Passport system and CSS system will be replaced by or upgraded by Cornerstone projects.

a. Please advise whether the Passport and CSS systems have been fully depreciated or not.

b. If not, please provide the remaining life of each of these two systems.

c. Please provide the amount of the expected write-off(s), if any, which would be associated with each of these two systems.

Response

a. Hydro One's CSS and Passport systems have been fully depreciated, with the exception of a small amount related to post in-service enhancements to Passport that have a remaining net book value of less than $2 K.

b. The remaining $2 k of Passport net book value will be depreciated in 2008.

c. No write-offs will occur as a result of retiring these 2 systems.

Ontario Energy Board (Board Staff) INTERROGATORY #43 List 1

Interrogatory

Ref: Exhibit A, Tab 3, Schedule 1 and Exhibit A Tab 15 Schedule 1– Reliability Performance/ Issue 1.6
Hydro One states at page 16 of Exhibit A Tab 3 Schedule 1 that: "an event is considered *force majeure* when it impacts more than 10% of customers serviced by Hydro One Distribution".

Board staff notes that *force majeure* events are generally referred to as those events that are beyond the reasonable control of the firm, including natural disasters such as tornados, earthquakes, hurricanes, flood, other acts of God, acts of any Government, civil disorder, or similar incidents.

Please list, in a table format, all events from 2002 to 2007 impacting more than 10% of customers serviced by Hydro One Distribution that were not caused as a result of any *force majeure* events as defined above by Board staff. In the table, for each event, indicate the geographical location affected, date(s) of occurrence, the reason for the outage, number of customers impacted, percent of customers affected, duration of outage, restoration time, and the cause.

Response

All events impacting more than 10% of customers serviced by Hydro One Distribution are considered to be *force majeure* as a result of being "beyond the reasonable control of the firm". The details requested are provided for force majeure events experienced in 2004 to 2006 as part of Exhibit A, Tab 15, Schedule 1, Pages 8 to 11 of the evidence in this Application. For details on 2007 force majeure events please see the interrogatory response at Exhibit H, Tab 12, Schedule 9, part a.

Ontario Energy Board (Board Staff) INTERROGATORY #44 List 1

Interrogatory

Ref: Exhibit A Tab 3 Schedule 1 – Reliability Performance/ Issue 1.6
For the pie charts shown in Figures 4 and 5 on pages 18-19, Please define the following categories, including identification of the differences between the two in each pair, a description of an example for each, and the industry standards that Hydro One used to define the category:

a. "Tree contacts" and "*Force Majeure* -Tree contact"
b. "Defective Equipment" and "*Force Majeure* – Equipment"
c. Please define "*Force Majeure* – Other" and provide detail for causes for the outage, i.e., hurricanes, etc.

Response

Hydro One defined "*Force Majeure"* in the evidence at Exhibit A, Tab 15, Schedule 1, Page 4 of 11.

The 2006 Electricity Distribution Rate Handbook, Table 15.2, Cause of Service Interruption, Page 142, May 2005 is the standard that defines:

a. "Tree Contacts" as customer interruptions caused by faults resulting from tree contact with energized circuits.

   In the chart, "*Force Majeure* -Tree contact" identifies interruptions caused by "Tree Contacts" that occurred during events that met Hydro One's definition of *Force Majeure.*

   The difference between the definitions is the condition under which the interruption occurred.

b. "Defective Equipment" as customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures, detected by maintenance.

   In the chart, "*Force Majeure* – Equipment" identifies interruptions caused by "Defective Equipment" that occurred during events that met Hydro One's definition of *Force Majeure.*

   The difference between the definitions is the condition under which the interruption occurred.

c. "Unknown/Other" as customer interruptions with no apparent cause that contributed to the outage.

In the chart, "*Force Majeure* – Other" identifies interruptions with "Unknown/Other" (no apparent) cause, that occurred during events that met Hydro One's definition of *Force Majeure.*

The difference between the definitions is the condition under which the interruption occurred.

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Interrogatory

Ref: Exhibit A Tab 3 Schedule 1, Pages 18 and 19, Figures 4 and 5 – Reliability Performance/ Issue 1.6
Hydro One provides pie charts in Figures 4 and 5 on pages 18 and 19 of the exhibit. It also states that the "*Force Majeure* – Equipment" factor contributed 7% to the four year average (2003-2006) in SAIDI and 4% to the four year average (2003-2006) in SAIFI.

a. Please provide the equipment types and details for various causes resulting in the "*Force Majeure* – Equipment" factor contributing to the stated SAIDI and SAIFI measures.
b. Please determine if and to what degree each of the following contributed to the "*Force Majeure* – Equipment" factor:
    I) "Equipment operating conditions";
    II) "Equipment physical condition, e.g. equipment age, etc.";
    III) "Equipment engineering design";
    IV) "System operating conditions";
    V) "Load and system demand";
    VI) "Manufacturing defects".
c. Please indicate if a different level or cycle of equipment maintenance and replacement programs employed by Hydro One, i.e. increased or decreased expenditures, could have affected the "*Force Majeure* – Equipment" factor, resulting in different values for SAIFI and SAIDI.

Response

a. Hydro One does not currently track information "equipment type" contribution to SAIDI and SAIFI as it is not a level of detail required in the 2006 Electricity Distribution Rate Handbook.

b. The main factor that contributed to "Force Majeure – Equipment" was the weather conditions at the time of the interruptions. Details of the 2004 to 2006 Force Majeure events are provided in Exhibit A Tab 15 Schedule 1 Page 8 to 11 and details of the 2002 and 2003 events are provided in Exhibit A, Tab 15, Schedule 1, Page 8 of 10 evidence of the 2006 Rate proceeding RP-2005-0020/EB-2005-0378. The detailed information requested in items I) to VI) is not known.

c. Hydro One's pole and equipment replacement programs have been designed to cost effectively address the end of life condition of components and equipment. Increased funding in replacement programs would remove assets that have some remaining life and in most cases the replacement assets will not perform better during severe storm conditions than the existing assets. As such, one would not expect any noticeable

improvement in reliability performance (i.e. SAIDI and SAIFI) during force majeure events under this type of scenario.

On the other hand, if the funding for replacement programs is reduced over an extended period of time, the condition of the assets would deteriorate to a point where a large percentage of the assets would be at end of life. This would result in a greater number of failures and poorer reliability performance during force majeure events.

Similar to replacement programs, it is expected that an increase in equipment maintenance programs (e.g. line patrols, asset condition assessment) from the currently optimized levels, could be expected to provide limited improvements in reliability during force majeure events due to the severity and stresses imposed by these events on the assets. Reductions in these programs would result in an increase in end of life assets, as there would be limited means to identify deteriorating assets and develop mitigating action plans. This being the case, one would expect an increase in failures leading to poorer reliability performance during force majeure events.

Ontario Energy Board (Board Staff) INTERROGATORY #46 List 1

Interrogatory

Ref: Exhibit A Tab 3 Schedule 1 – Reliability Performance/ Issue 1.6
With respect to Figures 4 and 5 on pages 18-19, Hydro One states that: "*Force Majeure* – Tree contact" contributed to 43% to four year average (2003-2006) in SAIDI and 14% to four year average (2003-2006) in SAIFI.

a. Please provide further details on how and why outages categorized under the "*Force Majeure* – Tree contact" factor contributed to the increases in the four-year averages for SAIDI and SAIFI performance.
b. Please indicate if a different level or cycle of vegetation management program employed by Hydro One, i.e. increased or decreased expenditure or cycle, could have affected the "*Force Majeure* – Tree contact" factor, resulting in different values for SAIFI and SAIDI.

Response

a. The increases in the four-year averages for SAIDI and SAIFI performance provided in the reference include all events that contribute to reliability performance, and as such, the increased frequency and duration of events categorized by Hydro One as Force Majeure contribute to the overall performance.

   Force Majeure typically involves a combination of rapidly moving storms, high winds, ice, snow and thunderstorms which can cause trees to fall on power lines or tree limbs to contact conductors, thereby resulting in customer outages that contribute to overall SAIDI and SAIFI performance.

b. Yes, a fully implemented shorter vegetation management cycle could be expected to reduce the impact on "*Force Majeure* – Tree contact", while increasing the clearing cycle could be expected to increase the impact over time.

Ontario Energy Board (Board Staff) INTERROGATORY #47 List 1

Interrogatory

Ref: Exhibit A Tab 3 and Exhibit A Tab 15 Schedule 1– Reliability Performance/ Issue 1.6
On page 17 of Exhibit A Tab 3 Schedule 1, Hydro One states, "Excluding *force majeure* events, performance for both SAIDI and SAIFI has remained relatively consistent during 2003 to 2006 period, with performance in 2006 remaining stable or improving relative to 2005. Including *force majeure* events performance has varied significantly from year to year due to variations in the number and severity of storms that have affected the Hydro One Distribution System in a given year." Hydro One provides further details on *force majeure* events from 2004 to 2006 in Exhibit A Tab 15 Schedule 1.

a. Please provide information in a table format, for each of the *force majeure* events, as defined by Hydro One, identifying (as "Yes" or "No") whether the number of customers impacted, outage duration, and restoration time would have been affected, if Hydro One had made a change in any of the "Impacting Factors" shown in the following table

Impacting Factor	**Number of Customers Impated (A)**	**Duration of Outage (B)**	**Restoration Time (C)**	**Rational for Impact, if any, for A, or B, or C and the Extent of Impact**
Level and cycle of equipment maintenance and replacement programs				
Level and cycle of vegetation management program				
Number of advanced automated technologies, e.g. sectionalizes, breakers, etc.				
Investment level in distribution system equipment and upgrades				
Number of communication devices associated with the equipment				
Number of communication devices with the field staff Engineering design of distribution system				
Restoration time				
Level of crews				
Crews schedules				
Crews travel time				
Number of de-centralized, but integrated, operation centers, e.g., trouble crew centers				
Number of de-centralized, but integrated, distribution operations and maintenance centers				

b. If the answer is "Yes" to any of the impacting factors for one or more outages listed in the tables for a), please state if Hydro One has planned any initiatives in

2008 to minimize the effect of possible future *force majeure* events and to enhance Hydro One Distribution's reliability performance

Response

a) The force majeure events experienced by Hydro One Distribution over the last 4 years have a number of common elements: i.e., large number of customers affected (>10% of the customer base per storm), affected area has a large geographic footprint, high winds, and in some cases accompanied by ice and wet snow. The response below is based on these commonalities rather than providing a separate table for each storm as these factors would have similar impacts in all cases.

The definition assumed for "duration" and "restoration time" in completing the table below are:

- Duration - includes the time the outage is identified until power is restored.
- Restoration Time – includes the time for field crews, once dispatched, to restore power

Impacting Factor	Number of Customers Impacted (A)	Duration of Outage (B)	Restoration Time (C)	Rational for Impact, if any, for A, or B, or C and the Extent of Impact
Level and cycle of equipment maintenance and replacement programs	Yes	Yes	Yes	Refer to Exhibit H, Tab 1 Schedule 45 section c
Level and cycle of vegetation management program	Yes	Yes	Yes	Refer to i) below.
Number of advanced automated technologies, e.g. sectionalizes, breakers, etc.	Yes	Yes	Yes	Refer to ii) below
Investment level in distribution system equipment and upgrades	Yes	Yes	Yes	Refer to iii) below
Number of communication devices associated with the equipment	No	Yes	Yes	Refer to iv) below
Number of communication devices with the field staff Engineering design of distribution system	No	Yes	Yes	Refer to v) below
Restoration time	No	Yes	Not applicable	Restoration time does not affect the number of customer impacts, but does impact outage duration.
Level of crews	No	Yes	Yes	Crew availability and location does not impact number of customer impacts, but can impact restoration time and duration.
Crews schedules	No	No	No	Crews are redirect to the storm restoration as the need arises regardless of schedule.
Crews travel time	No	Yes	Yes	Travel time impacts restoration time and in turn outage duration

Impacting Factor	Number of Customers Impacted (A)	Duration of Outage (B)	Restoration Time (C)	Rational for Impact, if any, for A, or B, or C and the Extent of Impact
Number of de-centralized, but integrated, operation centers, e.g., trouble crew centers	No	No	No	Hydro One has a mobile work force and can be deployed to problem locations effectively as needed. The number of work centres established has taken this into consideration.
Number of de-centralized, but integrated, distribution operations and maintenance centers	No	No	No	Crews are generally redeployed from a number of operations and maintenance centres. Additional centres are not expected to improve restoration times .

i) Vegetation Management

Increased funding in vegetation management would reduce the maintenance interval and in turn the number of trees that would be susceptible to contacting distribution lines. Increased maintenance would on average increase the health of trees adjacent to Hydro One lines, which would reduce the number of tree contacts during these severe events. Fewer tree contacts would reduce overall outage durations. The extent to which vegetation management is increased in areas susceptible to force majeure events would also be a contributing factor. In addition customer outages are expected to reduce in areas adjacent to the force majeure event.

ii) Advanced Automated Technologies

Added automated sectionalizers and breakers would reduce the impacts of force majeure storms as follows:

- Customer interruptions would be more contained to the storm areas as a result of isolating that portion of the feeder that extend outside of the impacted areas.
- Automated tie switches and sectionalizers would see some improvement in restoration time and duration, as crews could reconnect customers in a more expedient manner.

iii) Distribution System and Equipment Upgrades

Upgrades can take many forms, i.e., bury lines to reduce the impact from trees, more robust design standards, add redundancy of supply, higher poles to place the conductor above trees, wider rights-of-way to reduce tree contacts. These alternatives, if implemented to an appropriate degree,

would reduce frequency and duration of customer impacts, and improve restoration times.

iv) Communication Associated with Equipment
Added communication devices for equipment, i.e., Smart Meters and Distribution System Monitoring, would not prevent customer impacts, but would provide a somewhat earlier notification of the extent of the problem and could be used to direct staff to the key problem areas in a more expedient manner, thereby improving restoration and reducing the duration of outages.

v) Communication Devices with Field Staff
These could include GPS locators and lap tops with wireless communication paths. There would not be an improvement in customer impacts, but there would be an improvement in restoration times due to improvements in identifying material requirements and delivery. With GPS, crew locations would become transparent, facilitating improved coordination of crews and thereby improving restoration times. As restoration times improve, customer outage durations are reduced

b) The following are 2008 initiatives implemented by Hydro One Distribution to improve reliability where an expressed benefit has been noted.

i) Equipment maintenance and replacement – continue to replace end of life equipment to prevent reliability deterioration during storms.
ii) Vegetation management – reduction of maintenance cycle from the current average of about 10 years. Refer to Exhibit C1, Tab 2, Schedule 2, page 29.
iii) Continuation of the sectionalizer program. Refer to Exhibit D1, Tab 3, Schedule 3, page 9.
iv) Communication devices associated with equipment – Smart Metering and Station Monitoring. Refer to Exhibit D1, Tab 2, Schedule 2, page 24 for Smart Meters and Exhibit D1, Tab 3, Schedule 3, page 9 for Station Monitoring.
v) Communication with field staff – Hydro One has included investments for Mobile IT as highlighted in Exhibit D2, Tab 2, Schedule 3. In addition, new technologies have been implemented that make additional capabilities of the Outage Management System available to field supervisors during storm events. This has improved 2-way communications thereby providing more up to date information and improvement in crew dispatch
vi) Level of Crews and Crews Travel Time are not specifically highlighted in the evidence, but are none the less important considerations for process design and staff deployment.
vii) Restoration Process Improvements - Hydro One has implemented process improvements to assess damage, material needs and work equipment and

manpower requirements during major events. This process allows improved work planning, reduces repair time by having the right material and equipment available for restoration. In addition, storm restoration process improvements have been implemented that accelerate decisions for crew mobilization across the province utilizing a centralized communication structure. This results in additional resources being available sooner and in turn reduces outage duration.

Ontario Energy Board (Board Staff) INTERROGATORY #48 List 1

Interrogatory

Ref: Exhibit A Schedule 5 Tab 2, Attachment A – Hydro One Distribution Benchmarking Study / Issue 1.6 and Issue 4.8
The Hydro One Distribution Benchmarking Study from 2004 – 2006 dated October 24, 2007 conducted by PA Consulting Group states the following on page 4-20 under section 4.2.2:

"Asset Replacement Rates:
In the area of asset management rates, the low numbers provide some reason for concern. **In particular, Hydro One is replacing its assets at a very low rate, both in comparison to the panel and in general.** While the figures investigated are only on a 3-year average basis, if the replacement rate is indicative of the long-term capital replacement rate, it would indicate an extraordinary long life expectancy for some of the electric system." [Emphasis added]

With respect to benchmarking of Hydro One's reliability, the following is stated in the Executive Summary at page 1-5:

"Reliability:
Hydro One has comparatively poor reliability within the panel group, when measured by metrics such as SAIDI and SAIFI."

Further, on page 4-20 of the Benchmarking Study, under section 4.2.3:

"For Hydro One, using reliability metrics as modified for line length, which better represents the rural nature of Hydro One electric system, shows Hydro One performance is average, with reasonable expectations of improvements. Using SAIDI and SAIFI metrics, **the electric system reliability compared against its peers is poor on a 'customer experience' basis**. Given the nature of the service territory, the ability to compare favourably on the customer experience basis is very limited. It is possible to improve on the current performance, but it would be extraordinarily expensive to achieve first-quartile performance on the SAIFI/SAIDI metrics".

a. Please provide an explanation of why the consultant concludes that Hydro One is "replacing its assets at a very low rate both in comparison to the panel and in general"
b. Please state if Hydro One agrees with the statement, "replacing its assets at a very low rate both in comparison to the panel and in general".
c. Please state if Hydro One agrees with the statement, "…electric system reliability compared against its peers is poor on a 'customer experience' basis". Please provide an explanation on the possible reasons that Hydro One's "electric system

reliability compared against its peers is poor on a 'customer experience' basis" as documented in the benchmarking study.

d. Please provide an explanation on the possible relationship between Hydro One's reliability performance and relatively low rate of asset replacement as identified in the benchmarking study.

e. Please describe in detail how Hydro One intends to address the concerns in the areas of asset management and reliability noted in the Hydro One Distribution Benchmarking Study. Please state if and how these issues are addressed in Hydro One's 2008 distribution rate application.

f. Please describe areas of utility best practices that Hydro One can learn from and adopt from the Hydro One Distribution Benchmarking Study conducted by PA Consulting. Please include a cost impact analysis in your response.

Response

a. In the appendix to the consultant's report is a series of charts showing asset replacement rates. Asset replacement rates, for the purpose of this study, are calculated as the value of capital spending as a % of the capital asset base. Overall, Hydro One is replacing its capital at a rate just under 2%, as compared to the panel average of 3.1%. In comparison to the panel as a whole, Hydro One is replacing the assets more slowly. For an explanation regarding Hydro One's approach to replacement, please see section (e) below.

b. Yes, given how replacement rates are defined.

c. Yes, when measured against the rest of the comparison panel on a SAIDI or SAIFI basis, Hydro One fares relatively poorly. SAIDI and SAIFI measure customer experience in terms of the number and duration of interruptions they experience. Hydro One has the least densely populated service territory of any company in the panel. That means there is greater exposure to reliability problems for Hydro One assets than for the other utilities. In particular, greater lengths of line are needed to serve each Hydro One customer versus those of other utilities. Greater amounts of line increases the exposure to weather and the number of assets susceptible to equipment failure, which increases the opportunity for an interruption.

d. Without an understanding of a multi-year (about ten years rather than three years) history of the electric system reliability as compared to the asset replacement rate, it would be speculative to identify a relationship between the reliability performance for the asset in question and the asset replacement rate. Over an extended period, the rate of asset replacement can be expected to have an impact on electric system reliability. In particular, the asset replacement rate would be expected to influence the relative change in the reliability performance more than it would affect the overall level of reliability.

e. Hydro One uses a centralized asset management approach that relies on end-of-life criteria to determine replacements as well as optimizing life cycle costs. The 2008 Sustaining Capital Program requirements are based on these aspects, and other considerations such as asset condition, reliability performance and obsolescence. As a result, Hydro One Distribution believes the historical and proposed expenditures contained in Exhibit D1, Tab 3, Schedule 2 are prudent. Going forward, Hydro One anticipates that capital replacement needs will increase substantially as equipment demographics for items such as transformers and poles shift. This need has already surfaced as evidenced in the required increases to the 2008 planned line refurbishment and component replacement programs. Another example of this is contained in Exhibit D1, Tab 2, Schedule 1, page 15, which explains that pole demographic and condition analyses predict that pole replacements will need to increase over the next 10 years to keep up with the aging of the plant. When these increases to the capital work program are implemented, Hydro One anticipates that the asset replacement rates will increase to continue appropriately managing key business risks (reliability and public / employee safety) as assets age, while minimizing life cycle costs.

The reliability concerns highlighted in the benchmarking report are addressed in the 2008 rate application primarily through the Vegetation Management Program and through Reliability Enhancement Projects. As shown in Exhibit A, Tab 3, Schedule 1, Hydro One's analyses of reliability performance (i.e. SAIDI and SAIFI) indicate that "Tree Contacts" are by far the greatest contributor to unreliability. The increases in expenditures in the Vegetation Management Program target reliability improvement as detailed in the interrogatory response at Exhibit H, Tab 1, Schedule 49.

f. The key opportunity area to take from the benchmarking study which would result in better performance for the Hydro One distribution system would be an increase in vegetation management.

Ontario Energy Board (Board Staff) INTERROGATORY #49 List 1

Interrogatory

Ref: Exhibit A-15-2, Attachment A, Hydro One Distribution Benchmarking Study and Exhibit A, Tab 14, Schedule 5 – Tree Trimming/ Issue 4.3

Hydro One Distribution Benchmarking Study from 2004 – 2006 dated October 24, 2007 conducted by PA Consulting Group states at pages 4-21 "The only variable about the tree trimming practices which was tracked for this study is the length of the tree-trimming cycle for each of the companies. **Hydro One has by far the longest cycle time between consecutive trimming of each tree**. It would be worth investigating to see whether that has led to greater difficulty in performing the trimming when the time comes for each tree or circuit. It is also conceivable that this long cycle leads to more "hot-spot" trimming than usual, which is typically more expensive than routine cycle trimming. Previous studies executed by PA Consulting have indicated that **the optimum tree-trimming cycle length is nearer to 5-6 years than to the 11 currently in practice at Hydro One**.

One additional area of interest for further study would be the relationship between the long cycle time of tree-trimming and the reliability results.
Shortening of the cycle time will probably have the benefit of reducing the frequency of the % of interruptions caused by trees and how much those could be reduced by a differently-structured tree-trim program."

a. Please state if Hydro One agrees with the statement- "The optimum treetrimming cycle length is nearer to 5-6 years than to the 11 currently in practice at Hydro One".
b. Please state if Hydro One agrees with the statement, "Shortening of the cycle time will probably have the benefit of reducing the frequency of the % of interruptions caused by trees".
c. Please provide an explanation if the long cycle for tree trimming may have contributed to long duration of outages affecting Hydro One Distribution's network performance either during *force majeure* or non-*force majeure* outages.
d. Please provide an explanation for Hydro One's selection of its current 11- year tree trimming cycle.
e. Has Hydro One performed a "Business Value Evaluation Matrix" (as shown on page 7 of Exhibit A Tab 14 Schedule 5) for its 2008 vegetation management program? If so, please provide the results showing the impacts, risks, and cost profiles due to a reduced tree trimming cycle. If not, please explain why not.

Response

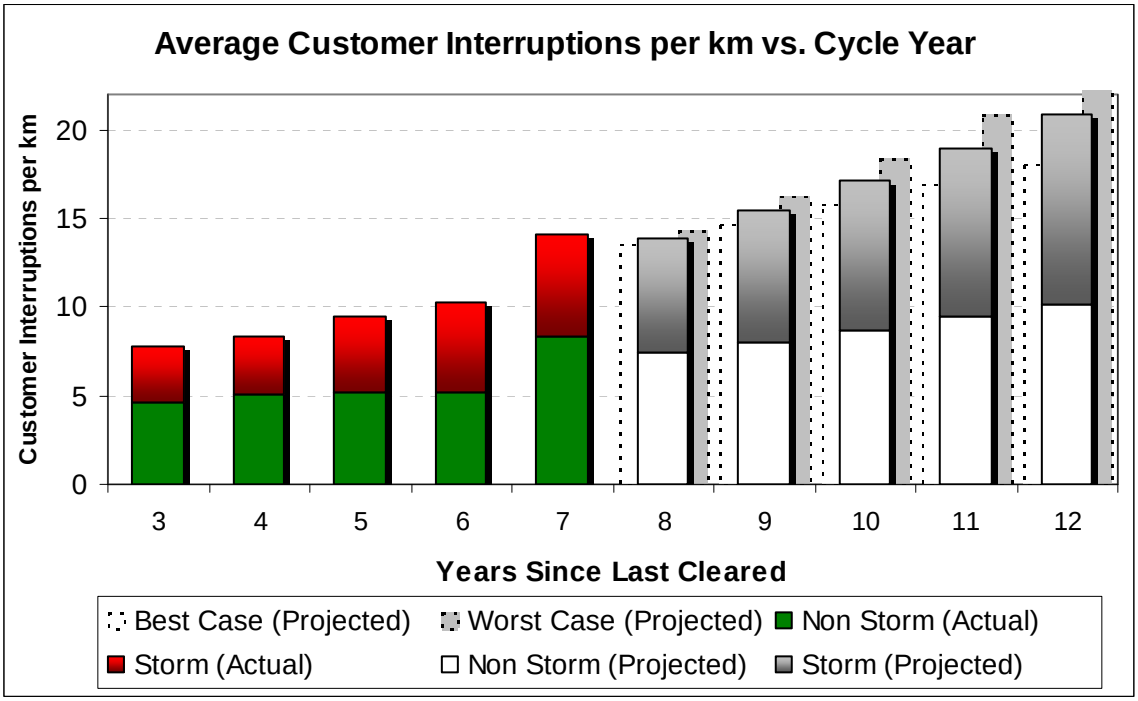
a. Hydro One agrees that the optimum tree-trimming cycle length is nearer to 5-6 years than to 11 years. Determining the optimum cycle length for a particular system is challenging as it requires detailed analysis of various factors including reliability, cost, vegetation type, growing conditions, and other impacts that include herbicide usage and conditions that threaten the health of trees, e.g., emerald ash borer.

Hydro One has information (e.g. Griffiths Report, 2008 Hydro One Vegetation Management Program Review provided as Attachment A to this interrogatory) that points to 7-8 year cycle based on reliability improvements. Hydro One has selected to implement the upper bound of this range (i.e. 8-year cycle). This approach is considered to be the most prudent at this time as it will:

- improve reliability (see answer parts b and c); and,
- reduce long-term costs by lowering future maintenance unit costs and reducing the system's susceptibility to trouble calls and other reactive costs

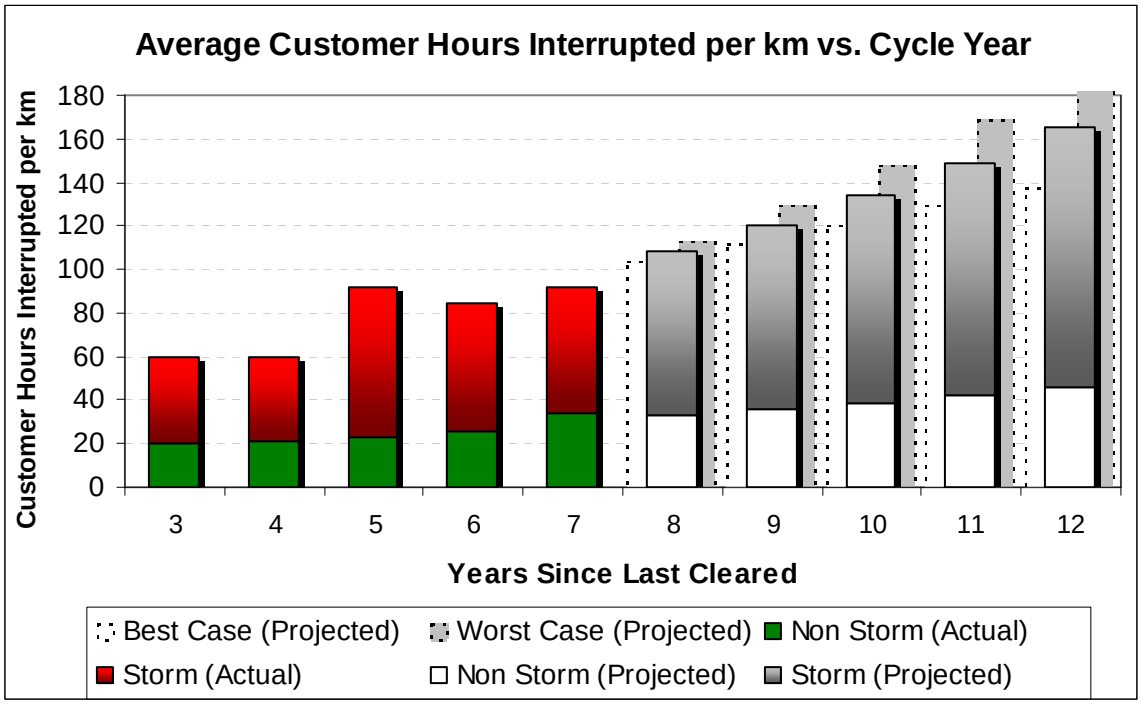
During the implementation of an 8-year cycle, Hydro One will continue to assess the cost and benefits of implementing even shorter cycles as suggested by PA Consulting and others, and if there is a net benefit, will recommend a further increase to the frequency of vegetation maintenance as part of a subsequent rate hearing.

b. Yes, Hydro One agrees that shortening the cycle time will have the benefit of reducing the frequency of interruptions caused by trees. Hydro One measures the frequency of interruptions using SAIFI, which is driven by "customer interruptions". For this measure, internal study has shown that the longer the cycle (i.e. time since clearing), the greater the number of customer interruptions that can be expected. The chart below illustrates this fact using Hydro One's experience and provides projections for longer cycle lengths.



The chart is based on Hydro One data up to year 7. Data of sufficient quantity was not available beyond this time frame, and as such these bars represent projected values that include and upper and lower bounds.

c. Cycle lengths do contribute to outage durations under both force majeure and non-force majeure conditions and therefore contribute to network performance. Hydro One measures the duration of interruptions using SAIDI, which is driven by "customer hours" of interruption. For this duration measure, internal study has shown that the longer the cycle (i.e. time since clearing), the greater the number of customer hours of interruption that can be expected under both force majeure and non-force majeure conditions. The total number of customer hours is not only impacted by the increased number of outages, but also the increase in time it takes to clear tree damage, as the scope of the damage is greater as the cycle time is extended. In addition, with an increase in cycle duration greater amounts of brush remain on the rights of way which can interfere with restoration efforts thereby extending restoration times. The chart below illustrates this fact using Hydro One's experience and provides projections for longer cycle lengths.



d. The reference to an 11-year cycle is based on the actual accomplishments in 2006. This one year snapshot is not indicative of Hydro One's "selected" cycle. 2006 was an exceptionally severe storm year in which forestry resources had to be diverted to storm restoration activities, and prevented us from achieving our planned program based on a 10 year cycle.

e. Yes, as part of the investment prioritization process Hydro One has performed a "Business Value Evaluation Matrix" for the 2008 Vegetation Management Program. That matrix is below.

Business Value Assessment

			Normalized Risk						
	Total Cost over 5-yr Plan		Financial	Reputation	Regulatory	Reliability	Efficiency	Safety/ Environ	Customer
Minimum – 9 Year	522.5	Impact	Severe	Severe	Severe	Severe	Major	Major	Major
		Likelihood	Medium	Medium	Medium	Medium	Very	Very	Very
Level 1 – 8 Year	582.2	Impact	Major	Major	Major	Major	Major	Major	Major
		Likelihood	Likely	Likely	Likely	Likely	Medium	Likely	Medium
Level 2 - 8 Year to 7 Year	639.7	Impact	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate	Moderate
		Likelihood	Likely	Likely	Medium	Very	Very	Very	Medium
Level 3 - 7 Year	658.7	Impact	Minor	Minor	Moderate	Minor	Moderate	Moderate	Moderate
		Likelihood	Likely	Likely	Unlikely	Likely	Unlikely	Unlikely	Unlikely
Level 4 - 7 Year to 6 Year	715.0	Impact	Minor	Minor	Minor	Minor	Minor	Minor	Minor
		Likelihood	Unlikely	Unlikely	Remote	Unlikely	Unlikely	Unlikely	Remote

Vegetation Management Study

Mar. 4, 2003
(Recommendations on page 3 added October 12, 2005)

S.T. Griffiths, R.P.F.

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Tree Densities

Introduction

HydroOne's service area is, for the most part, located in rural Ontario, with a relatively low customer density and millions of trees. The forestry workload, and the number of tree caused power outages are directly influenced by the number of trees present in the vicinity of the power lines. The 1998 ECI study stated the tree density on Hydro One's distribution system is 62 trees per kilometre of line. Actual reported trees treated from 1998 - 2002 are less than 62 (most recently due to the ingrowth retention scheme). Lower tree density means lower tree-caused outages and less expensive line clearing, in the long term

Tree densities have increased over the past 15 years. Throughout the 1990's herbicide programs were virtually eliminated. In many locations, scheduled line clearing programs were replaced by "Hot Spotting", those areas in immediate need of treatment.

Recommendations (Added October 12, 2005)

Hydro One should assess different ways to significantly reduce the distribution forestry workload. Decreasing the time between successive treatments and increasing the tree removal rates will reduce future forestry workload, but there are additional means that can be employed to supplement the primary methods. The following recommendations are more administrative, innovative, and resource efficient:

1. **Maximizing efforts to retain the chemical option for brush control.** Develop centralized expertise who can react to all “local” situations that threaten this option. The selective chemical option is the single most effective tool to efficiently manage tree density. Many municipalities are enacting by-laws to restrict the use of herbicides for cosmetic use; the town of Huntsville and the district of Muskoka are currently debating the same type of bylaw. Hydro One should have a spokesman with a professional knowledge of this subject “on the ground” to spread the word of the importance of industrial herbicides for managing the “millions of stems of young forest type trees” that will threaten the reliability and security of the electric service, and the cost consequences to customers if this option is lost.

2. **Improve communications with customers regarding tree issues.** Rural Ontarians are more aware now than ever before the problems associated with trees and power outages. As a group, they should be more receptive to wider right of ways, the use of chemicals, more removals (when they are in the Company’s economic interest) because these initiatives will ultimately save them money. Also, Hydro One has recently acquired a number of urban utilities; communicating with them to not plant any trees near your lines makes sense. To summarize, the customers should not be part of the problem, but part of the solution. A forestry newsletter included with their bills and/or inserted in magazines directed to the customer base could be considered.

3. **Review the clearing specifications.** Are too many trees being treated, or the right species? Hydro One has come a long way in recording tree-caused outage information, but there is room for improvements; are there some tree species more liable to cause outages than others? A detailed analysis of tree caused outages can be fed back to clearing specifications, and these could vary for different parts of the province.

4. **Implement an auditing program** A forestry audit program is essential. Forestry managers are under pressure to meet production targets but are the jobs completed to specification? Forestry on the job performance, when a systematic auditing program is in place, tends to improve the product. The auditors, whether internal or external, should be trained and certified. There is a designated "Certified Environmental Auditor, Sustainable Forest Management" under the auspices of the Canadian Environmental Auditing Association. Internal professionals with this designation should be developed.

5. **Build Forestry Relationships with the Ontario Community.** Tree and wire conflicts are everyone's problem. Hydro One should be progressive and promote/establish relationships with provincial NGO's that comprise a significant portion of the customer base. Organizations such as the Ontario Forestry Association, the Ontario Woodlot Owners Association, the Federation of Ontario Cottagers Association, Ontario Federation of Agriculture etc. are, for the most part comprised of rural landowners with forest land. Active participation in these organizations and others could assist in communicating the "Tree message". Hydro One should have booths at fall fairs to promote the forestry message. This expertise could be acquired and trained, at minimal cost, utilizing university or community college students from forestry/biology programs. This message should typically include the importance of herbicides for Hydro One and no trees near powerlines.

Dx Line Clearing Cycles

Introduction

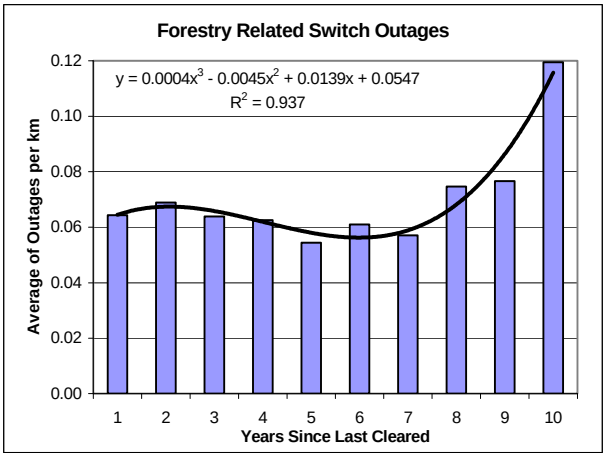
The Hydro One distribution system is comprised of 100,000 route km of overhead lines. At the present time the tree clearing cycle is approximately 10 years. Neighbour utilities maintain their lines every 5 to 7 years. Due to the vegetation conditions prevalent in the service area, 6 to 8 years clearance can be obtained (less in built up areas) utilizing acceptable arboricultural techniques. After these times vegetation grows into the conductors, increasing the clearing costs, risks and number of tree-caused outages.

Tree growing conditions vary throughout Ontario, which is divided into three forest zones, each featuring different types of trees and growing conditions. Trees in the southern (Carolinean) zone grow faster than those in the north (Boreal) zone with those in the central (Great Lakes St. Lawrence) zone in between. Different growth rates are discussed under brush control. The following rationale provides a business case for decreasing the clearing cycle.

System Reliability / Tree-caused Outages

Analyses of primary forestry related outages compared to when the lines were cleared identified that the number of outages per kilometre of line more than doubled 10 years after clearing compared to 7years after clearing. Over the 5 year planning period, $15,000,000 could be saved in trouble response with a 7 year average clearing cycle compared to the current 10 year cycle.

Chart 1: Forestry outages and years since last cleared



This is discussed in greater detail in **Appendix A**.

Financials

Four different funding levels were assessed for "Before tax net present values" (NPVs). The results are shown in table 1, below.

Table 1: NPV Analysis for each of the investment proposals

Funding Level	Investment Proposals		Before Tax NPV ($M)		
	Line Clearing	Brush Control	Line Clearing	Brush Control	Total
Minimum	10 Year	10 Year	(859)	(200)	(1,060)
Level 1	9.3 Year	6.8 Year	(868)	(187)	(1,054)
Level 2	8 Year	6.8 Year	(872)	(187)	(1,058)
Level 3	7 Year	5.8 Year	(885)	(185)	(1,070)

The NPV's were calculated over a 20 year period. Although the unit costs for line clearing decrease with shorter cycle intervals, the increased costs of reducing the cycles over the first few years overcompensates for reduced unit costs later on, so the lower cycles in Levels 2 and 3 do not have lower NPV's over the 20 year period. The detailed NPV's for the 4 funding levels are in Appendix B.

Discussion

The NPV's for the various funding levels are relatively close over the study period. Shorter brush control cycles feature lower NPV's while shorter line clearing cycles have higher NPVs. The line clearing cycles are driven by reliability and customer perception. Data shows that outages per kilometre double in years 7 through 10 of a line clearing cycle, and though there is no supportive data available, Chart 1, above suggests an exponential increase in outages beyond year 10. Customer perception is difficult to assess, but interviews with selected external customers and Hydro One customer service staff conclude there is an increasing perception that electrical service is deteriorating and trees are a major reason.

Recommendation

The ideal cycle for line clearing is 7 years, and Level 3 funding is recommended. A 7 year average cycle represents the maximum clearance that field workers can reasonably expect to attain with our growing conditions. Tree caused outages rapidly escalate after 7 years.

Dx Brush Control Cycles

Introduction

Most of the land associated with HydroOne's distribution system is capable of supporting woody vegetation that will grow into the conductors if not effectively managed. The brush must be controlled to prevent it from growing into the lines and causing outages, and to facilitate access for maintenance and repair. Government approved herbicides, applied selectively, is the preferred and most efficient brush control option.

Financials

Three different cycle scenarios were assessed for the four investment proposals: 10 years, 6.8 years and 5.8 years. Unlike line clearing, the shorter the cycle, the lower the NPV, as noted below:

Table 2

Brush Control	Brush Control NPV
10 Year	(200)
6.8 Year	(187)
6.8 Year	(187)
5.8 Year	(185)

Discussion

The methods and timing of controlling brush significantly impact the costs associated with the activity. A selective application of herbicide is the most efficient way of controlling brush. Repeated applications over succeeding cycles reduce the brush density (and subsequent future expenditures). To accomplish this, the brush must be retreated before it retains a height of 3 metres. If the brush is allowed to grow beyond 3 metres, more costly removal techniques must be employed. The schematic "Cost to Treat Trees/Brush Based on Height", below depicts the cost of treating various heights of brush and trees.

As was stated above, the growth of brush varies by location in the province, and, since there are identifiable height levels that are significant in terms of escalating cost thresholds, predictions can be made on establishing cost effective cycles. This is described in Brush Control, Optimum Cycles, **Appendix C.**

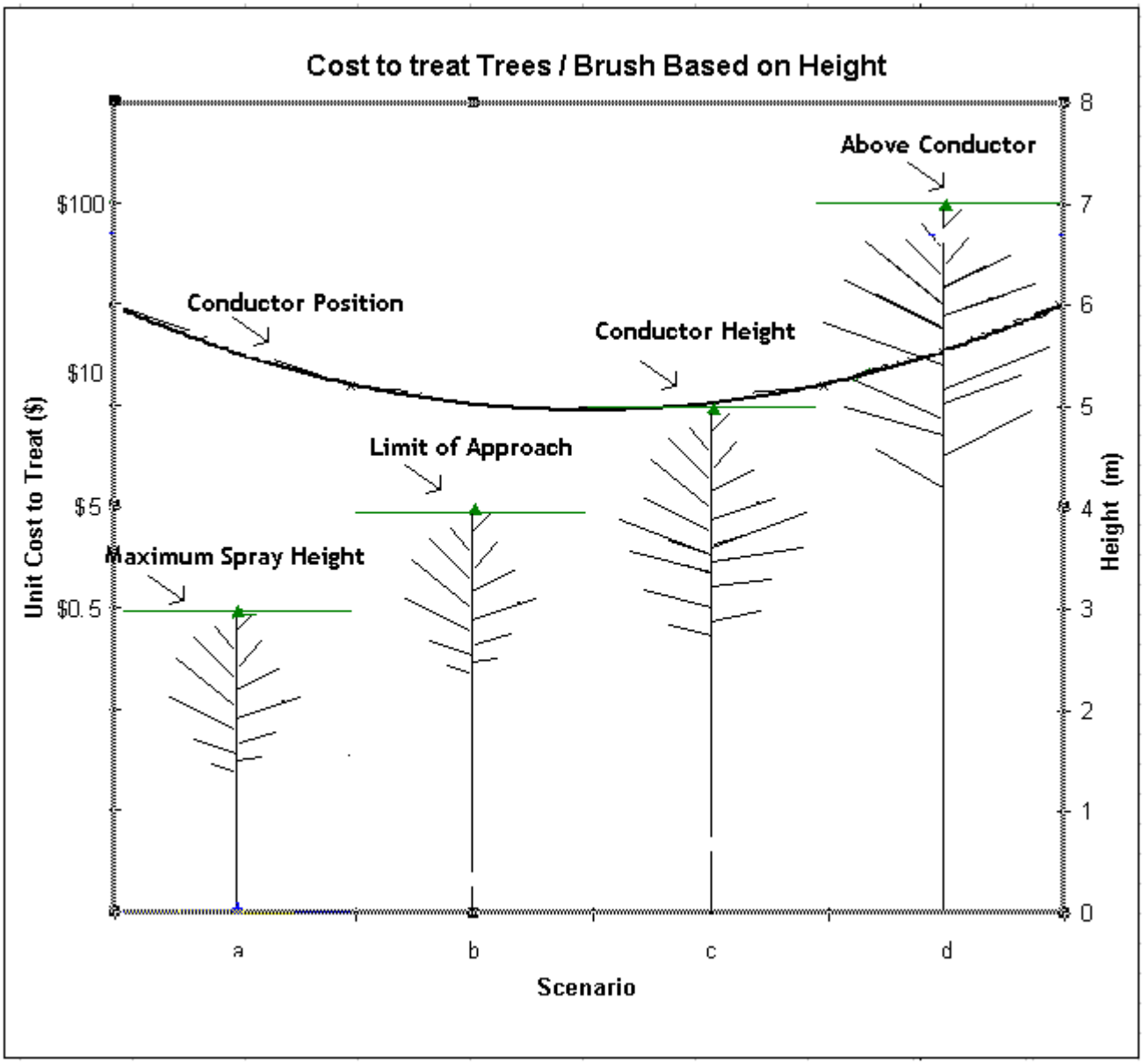


Chart 2

a Brush up to 3 metres tall, cost $0.50 to treat (Average age – 7 years)

b Brush over 3 metres but outside of limit of approach to energised conductor, cost $5.00 to cut, remove and pile/chip (Average age – 10 years)

c Brush within limit of safe approach to conductor, must remove with qualified personnel using live line tools. Cost to remove $10.00. (Average age – 12 years)

d A tree (classified as over 10 cm measured at breast height) Cost to remove: over $100.00.

Ingrowth Retention

Introduction

Tree branches have been left untreated at certain locations on single phase pole top pin construction since year 2000. This "Ingrowth" retention system was implemented to improve forestry line clearing production. Basically tree branches that are not into the line are not treated even if they will be over the next cycle. When the decision was implemented to allow the ingrowth, full life cycle costs were not available.

Discussion and Analysis

There are approximately 59,000 km of single phase line in Hydro One's system. Of that total, it is assumed that 40,000 km is eligible for the ingrowth retention system, the balance being crossarm construction or single phase in "public areas" that is treated normally. Single phase voltages range from 2.4 kv up to 16 kv. Although there have not been any detailed performance analyses undertaken, it is expected that the performance of the higher voltage single phase lines will deteriorate more rapidly.

The ingrowth retention system does not reduce tree density as trees are left untreated that would be cleared under normal circumstances. The greater the tree density, the higher number of outages.

The NPV's of the ingrowth retention and traditional line clearing system were compared. Based on this comparison, which included a mid cycle treatment for the ingrowth retention system, the traditional method has a lower NPV. This is further described in **Appendix E.**

Recommendation

Based on the preceding discussion and **Appendix E,** the ingrowth retention scheme should be abandoned, and replaced by a standard specification featuring cycle clearance.

Forestry Map Scaling Project

Description of Project

Forestry reports work accomplishment on a "route kilometre (km) basis". Double circuit lines and overbuild/underbuild are only counted once. There was uncertainty on the actual amount of distribution lines, so for planning purposes, all the route kms of lines were map scaled. The work was carried out by lines zone and operating centre.. The first step was to identify all the overbuild (subtransmission) on the primary distribution maps, so route line kilometres were only counted once. Double circuit lines were also only counted once. Since each feeder was being scaled, submarine and underground km were included, for use by other groups. Attempts were made to identify on / off road situations, and locations inaccessible to mechanized equipment. A tabular summary of the project by forestry district follows in Table 3. This updated information is being added to a revised forestry database.

Table 3 Forestry Scaling Project, 2002

District	multi phase km	single phase km	total km*	LV	Primary Dist	Urban km	Long cy km
1	7637	10206	17843	3733	14110	1600	12510
2	4631	7350	11980	1377	10603	1490	9113
3	2558	2379	4937	1424	3513	603	2910
4	2274	3288	5562	791	4772	449	4323
5	2749	3084	5833	765	5068	778	4290
6	2450	3005	5455	749	4706	580	4126
7	2467	4134	6601	653	5948	694	5254
8	3876	5964	9840	899	8941	1066	7875
9	1766	3234	5000	486	4514	708	3806
10	1384	3594	4978	342	4636	597	4039
11	1233	2671	3904	357	3546	81	3465
12	832	1243	2075	269	1806	265	1541
13	1818	2166	3983	389	3595	211	3384
14	2727	1967	4695	1115	3580	334	3246
15	1215	1849	3064	717	2347	64	2283
16	1238	2587	3825	131	3694	97	3597
Totals	40854	58722	99576	14197	85378	9617	75762

*Double circuit counted once; underbuild counted to highest voltage
Includes primary distribution and low voltage to 44kv

Recommendations

1. Utilize updated information for planning purposes.
2. Validate and revise database as new feeder information becomes available.

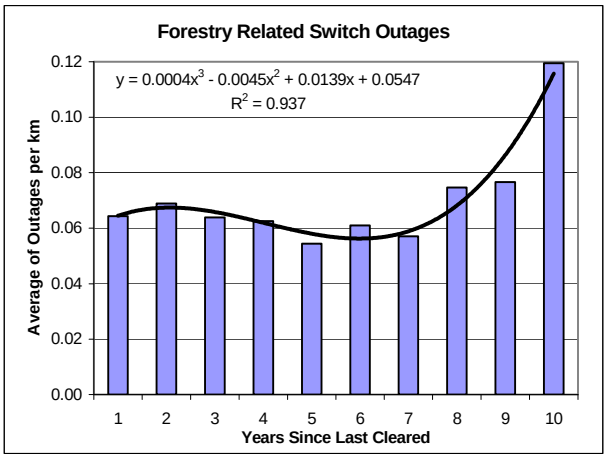
Appendix A

DM103 Attachment - Distribution Vegetation Management

1) Impact on Other Business Drivers

Vegetation management activities under DM103 have the potential to greatly impact the number of outages experienced by the Hydro One's distribution system. As a result, work achieved under this driver will affect Trouble Call and Storm Damage Restoration expenditures under DM101 and DC106.

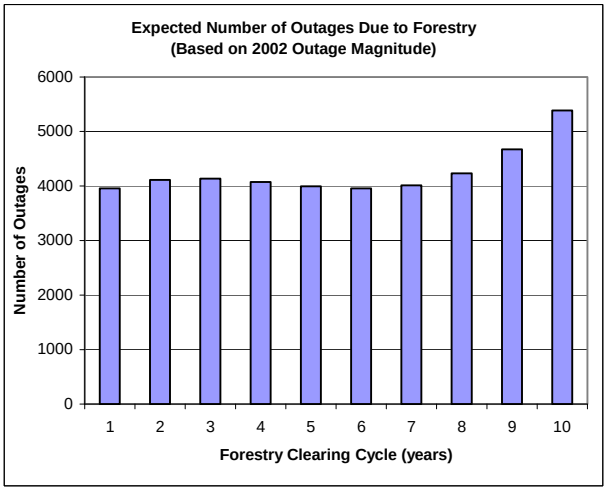
Chart 3: Expected Number of Forestry Related Switch Outages per km for HONI feeders cleared.



To assess the impact that vegetation management activities have on other drivers, the relationship between the number of outages and the tree clearing cycle used on HONI feeders was established. **Chart 3** to the left displays this relationship for feeders that were cleared during the past 10 years. For example, the average HONI feeder that was cleared 1 year ago can expect to have approximately 0.065 forestry related switch outages per km this year.

Switch Outages depending on the line clearing cycle.

Chart 4: Expected Number of Forestry Related



Using the relationship developed in **Chart 3** above, the number of outages that would be expected across the entire system can be predicted. **Chart 4** to the left shows the estimated number of forestry-related switch outages that can be expected for clearing cycles between 1 and 10 years.

Currently, the HONI system is assumed to be on a 10 year clearing cycle and is experiencing approximately 5300 forestry-related switch outages. **Table 4** below shows how a shorter forestry line clearing cycle would affect the number of outages experienced on the HONI system.

Table 4: Savings based on outage reductions as a result of shorter line clearing cycles.

Funding Level	Cycle (years)	Outage Savings per year	Incremental Outage Savings in year 1	Outage Savings in Planning Period: years 1 – 5	$M Savings in Planning Period: years 1- 5
Minimum	10	0	0	0	$0
Level 1	9.3	500	54	810	$4.1
Level 2	8	1,200	150	2,250	$11.3
Level 3	7	1,400	200	3,000	$15.0

The monetary savings quoted in **Table 4** above are based on the outage savings and on the approximate 2002 expenditure of $5000 per forestry related outage. It is concluded that vegetation management activities have the potential to save trouble call and storm damage expenditures (DM101 and DC106) between $0 and $15.0 million dollars depending on the funding level selected.

2) Financial

The following notes are relevant to the financial assessment of the investment proposals:

- The current forestry cycle is assumed to be approximately 10 years.
- The current vegetation condition was predetermined through past maintenance practices and is based on available information.
- It is difficult to relate the current system condition to an equivalent maintenance cycle as substantial hot spotting in past years makes it difficult to relate overall condition to a specific cycle.
- Unless improvements are made, it is expected that the forestry condition will deteriorate over the business planning period as a result of past maintenance practices.

Taking into account the above notes, the financial assessment estimated the expenditures associated with each of the investment proposals. Using these estimates over a 20-year planning period, **Table 5** below was constructed to illustrate the net present values at each funding level.

Table 5: Net Present Value (NPV) Analysis for each of the investment proposals.

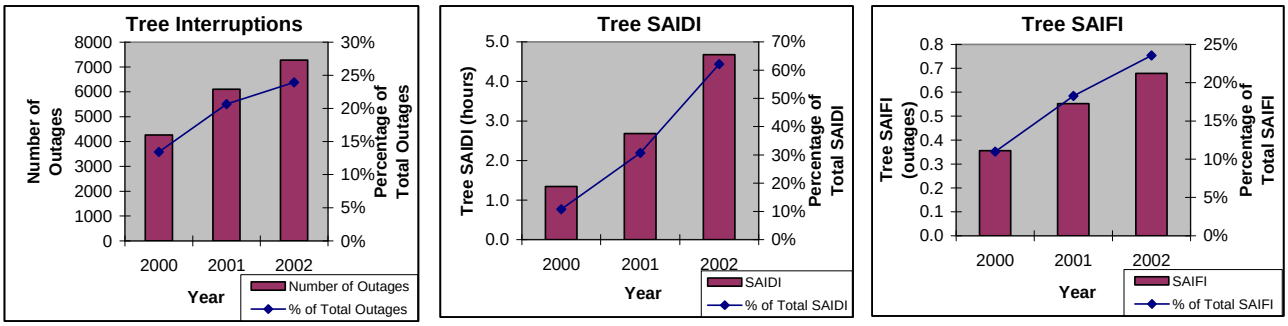
Funding Level	Investment Proposals		Before Tax NPV ($M)		
	Line Clearing	Brush Control	Line Clearing	Brush Control	Total
Minimum	10 Year	10 Year	(859)	(200)	(1,060)
Level 1	9.3 Year	6.8 Year	(868)	(187)	(1,054)
Level 2	8 Year	6.8 Year	(872)	(187)	(1,058)
Level 3	7 Year	5.8 Year	(885)	(185)	(1,070)

The net present values in the above table indicate that in the long term, financial differences between the investment proposals are negligible. These values are dominated by short-term (1-7 years) expenditures required to move from one cycle to the next.

3) Customer Reliability (Sensitivity Analysis)

Reliability data from 2000-2002 has shown that forestry interruptions have increased at a significant rate and that they are making larger contributions to overall SAIDI and SAIFI values. The charts included under Chart 5below illustrate this alarming trend.

Chart 5: Reliability trends over the years 2000 – 2002.



At the current pace, the trends illustrated in **Chart 5** above show that the HONI system can expect an increase of at least (minimum of the last two years:

- 1200 tree interruptions per year
- 1.3 hours per year to SAIDI

Appendix B: Net Present Value (NPV) Calculations

Minimum

10 Year Line Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)
Customer Contact	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)
Tree Related Reliability Cost	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)
NPV	**(73,757)**	**(69,191)**	**(64,907)**	**(60,888)**	**(57,119)**	**(53,582)**	**(50,265)**	**(47,153)**	**(44,233)**	**(41,495)**	**(38,925)**	**(36,515)**	**(34,255)**	**(32,134)**	**(30,144)**	**(28,278)**	**(26,527)**	**(24,885)**

10 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)
Customer Contact	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(17,205)**	**(16,140)**	**(15,141)**	**(14,203)**	**(13,324)**	**(12,499)**	**(11,725)**	**(10,999)**	**(10,318)**	**(9,679)**	**(9,080)**	**(8,518)**	**(7,990)**	**(7,496)**	**(7,032)**	**(6,596)**	**(6,188)**	**(5,805)**

Level 1

9.3 Year Line Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(41,720)	(39,918)	(39,723)	(39,528)	(39,334)	(39,139)	(38,944)	(38,750)	(38,555)	(38,360)	(38,166)	(37,262)	(37,262)	(37,262)	(37,262)	(37,262)	(37,262)	(37,262)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)
Tree Related Reliability Cost	(25,378)	(25,119)	(24,860)	(24,600)	(24,341)	(24,082)	(23,823)	(23,564)	(23,304)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)
NPV	**(78,791)**	**(71,979)**	**(67,123)**	**(62,593)**	**(58,366)**	**(54,422)**	**(50,744)**	**(47,312)**	**(44,110)**	**(41,226)**	**(38,571)**	**(35,735)**	**(33,523)**	**(31,447)**	**(29,500)**	**(27,674)**	**(25,961)**	**(24,353)**

6.8 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(18,297)	(17,380)	(16,462)	(14,942)	(14,040)	(13,305)	(12,193)	(11,926)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(21,549)**	**(19,354)**	**(17,348)**	**(15,019)**	**(13,391)**	**(12,027)**	**(10,525)**	**(9,703)**	**(7,846)**	**(7,360)**	**(6,904)**	**(6,477)**	**(6,076)**	**(5,700)**	**(5,347)**	**(5,016)**	**(4,705)**	**(4,414)**

Level 2

8 Year Line Clearing Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(46,091)	(45,408)	(44,724)	(44,041)	(42,602)	(41,414)	(40,501)	(39,588)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)
Tree Related Reliability Cost	(24,944)	(24,250)	(23,557)	(22,863)	(22,169)	(21,476)	(20,782)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)
NPV	**(83,485)**	**(77,025)**	**(71,044)**	**(65,509)**	**(59,801)**	**(54,224)**	**(49,771)**	**(45,663)**	**(42,194)**	**(39,581)**	**(37,131)**	**(34,832)**	**(32,675)**	**(30,652)**	**(28,754)**	**(26,974)**	**(25,304)**	**(23,737)**

6.8 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(18,297)	(17,380)	(16,462)	(14,942)	(14,040)	(13,305)	(12,193)	(11,926)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(21,549)**	**(19,354)**	**(17,348)**	**(15,019)**	**(13,391)**	**(12,027)**	**(10,525)**	**(9,703)**	**(7,846)**	**(7,360)**	**(6,904)**	**(6,477)**	**(6,076)**	**(5,700)**	**(5,347)**	**(5,016)**	**(4,705)**	**(4,414)**

Level 3

7.1 Year Line Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(51,581)	(50,449)	(48,589)	(46,489)	(44,976)	(41,826)	(40,009)	(38,309)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)
Customer Contact	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)
Tree Related Reliability Cost	(24,694)	(23,751)	(22,808)	(21,865)	(20,922)	(19,979)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)
NPV	**(89,904)**	**(82,392)**	**(74,823)**	**(67,679)**	**(61,587)**	**(54,800)**	**(49,049)**	**(44,926)**	**(41,616)**	**(39,039)**	**(36,622)**	**(34,355)**	**(32,228)**	**(30,233)**	**(28,361)**	**(26,605)**	**(24,958)**	**(23,412)**

5.8 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(20,881)	(19,146)	(15,898)	(13,769)	(12,553)	(9,930)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)
Customer Contact	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(24,615)**	**(21,463)**	**(17,276)**	**(14,449)**	**(12,613)**	**(9,926)**	**(8,850)**	**(8,302)**	**(7,788)**	**(7,306)**	**(6,853)**	**(6,429)**	**(6,031)**	**(5,658)**	**(5,307)**	**(4,979)**	**(4,670)**	**(4,381)**

Appendix C

Internal and External Communication

Introduction

The scope and magnitude of Hydro One's forestry activities create an impact on the province of Ontario. Every year the vegetation on thousands of hectares/kilometers is treated to maintain a secure supply of product, and reduce the risks of personal injury. There are various types of communication that take place during the execution of Hydro One's forestry programs (routine line clearing, brush control, stakeholder requests and emergency [storm] repair). These include external (stakeholders outside the company) and internal communication (contacts within the company necessary to carry out the programs). Inefficient or incomplete means of communication can cause expensive delays and/or interruptions to the programs.

Discussion and Analysis

Effective communication is required to ensure the work is carried out in an efficient manner. The very nature of the vegetation management activity can provoke a negative response from the customer (for example wanting to remove a significant portion of a shade tree on his front lawn or using herbicides to control brush). There is a process in place with Customer Relations to handle forestry related complaints.

Types of Forestry Communication

1. Internal

Communication between the various internal groups:

- Planning to Execution to Doers, three groups decide on objectives, targets and programs to achieve objectives; verified by audits, performance data; Services back to Planning.
- The Customer Care Centre, after receiving an external forestry call, to either forestry operations support staff or to customer relations, if the external call is a complaint.

2. External

There are various forms of external stakeholder interface with Hydro One's forestry programs:

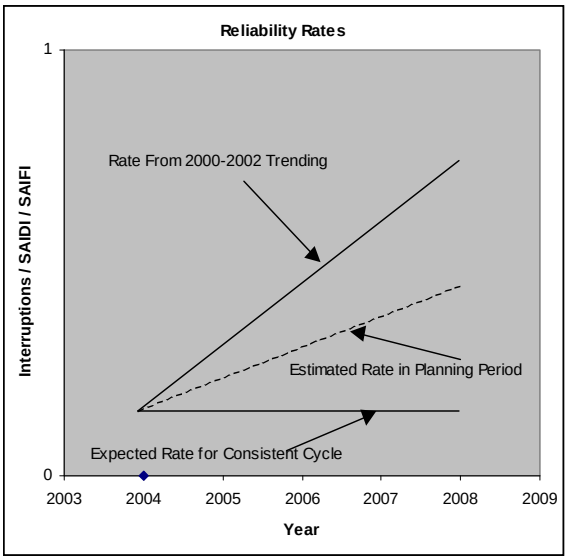
A. Providing External Communication

1. Customer/landowner notification - Hydro One makes a routine attempt to notify every landowner/customer of pending forestry activities.
2. General public - Hydro One periodically provides proactive information to the general public on matters that can have an impact on forestry programs. Examples are:
   - Bill stuffers providing where to plant/not to plant info (with respect to overhead and underground plant).
   - Magazine/newspaper advertisements identifying risks due to trees and power lines

- 0.1 interruptions per year to SAIFI

Increases in tree related interruptions, SAIDI, and SAIFI should naturally stop as a given line clearing cycle is adopted and implemented over a consistent period of time. Currently, the line clearing cycle is approximated at 10 years, but historic fluctuations in the work program have impeded the reliability metrics from reaching a plateau. To evaluate the investment proposals, the assumption was made that the rate of reliability deterioration over the planning period will be between zero (a plateau has been reached) and the current trends identified above. In general terms, Chart 6 below illustrates the estimation made.

Chart 6: Illustration of rates of increase for reliability indices.



Using the estimation illustrated in **Chart 6** to the left, the following rates of increase were determined for the current 10-year clearing cycle (corresponding to the minimum funding level):

- 500 tree interruptions per year
- 0.55 hours per year to SAIDI
- 0.04 interruptions per year to SAIFI

(These rates were derived using a 20% reduction for better reporting and assuming that over the planning period the rate will on average fall half way between the two extremes illustrated.)
Table 6 below shows how the minimum funding level will impact the reliability indices based on these rates.

Table 6: Reliability improvements at different points in the planning period.

Funding Level	Cycle (years)	Outage Rate (outages/year)	Outage Increase: Year 5 Outages – Year 0 Outages	SAIDI Rate (hours/year)	SAIDI Increase: Year 5 SAIDI – Year 0 SAIDI	SAIFI Rate (outages/year)	SAIFI Increase: Year 5 SAIFI – Year 0 SAIFI
Minimum	10	500	2,500	0.55	2.75	0.04	0.20

For funding levels other than the minimum, these rates will be less since a shorter cycle will reduce the number of tree related interruptions. Nevertheless, the potential for reliability deterioration under Levels 1,2, and 3 could exceed 0.2 hrs for SAIDI, and as such falls in the Major category with different probabilities for the different funding levels.

3. Specific Stakeholders - Hydro One will react to landowner/customer concerns about a planned or current forestry activity. This reaction usually takes place by:
   - Personal contact either in person or by phone in response to a query/complaint
   - Meeting with a group of customers/stakeholders to explain a forestry activity about to be carried out.
4. Regulators - applying for C. of A.'s and permits as required. (MNR and MOE)
5. Suppliers

B. Receiving External Communication

1. Customer/landowner query about:
   - Existing tree/vegetation conditions, including loss of power
   - Current forestry activity taking place
2. Group (municipality/ratepayer/cottage association)
   - Questioning specific maintenance practices
3. Regulators - C. of A., and permit approvals, violations
4. Other government (politicos)

Recommendations

1. All customer/landowner queries received should be logged by location/feeder to assist management in assessing the overall effectiveness of the forestry program.
2. Staff in the Customer Relations Centre be provided with current, approved forestry policies and procedures to assist in dealing with customers. (This has been informally done)
3. The Company should develop and implement strategies to ensure the most efficient vegetation techniques are retained or even enhanced.
4. Internal communication procedures should be implemented amongst the planning, program and services groups so required information is available in a timely manner.

Appendix D

Brush Control, Optimum Cycles

Introduction

Brush (young forest type trees) typically invades power line right of ways and, if left unmaintained, will grow into the conductors. Selective herbicide applied by ground crews is the preferred control option for treating brush, as this option leaves the dead brush standing eliminating disposal costs and reduces the number of tree stems over successive cycles. The optimum cycle is the one that has the lowest net present value. The main determining factor is brush height. The maximum brush height for herbicide application by ground crews is 3 metres to ensure complete coverage and efficient use of herbicide. Another reason to limit the brush height to 3 metres is the visual impact created by foliar applications. Significant financial penalties are incurred if the brush is allowed to grow above 3 metres, as noted in **Appendix B**.

Different species of brush exhibit different growth rates, and Ontario is divided into three forest type zones, determined by climate (growing season). Typical species found on right of ways in the different zones and the number of years to attain 3 metres are:

Table 7, Main brush species, and time to attain 3 metres

Forest Zone	Growing season (days)	Brush type	# years to attain 3 metres *
Boreal (north)	150-180	Poplar spp	7
		Spruce, black & white	13
		Balsam fir	13
		White birch	9
		Jack pine	13
Great Lakes - St. L	180-190	Maple spp	6
(Central)		White ash	6
		White pine	8
		Poplar spp	7
		Red oak	9
		White birch	9
Carolinian (South)	200-220	Maple spp	6
		White ash	6
		White elm	6
		Black walnut	6

* Data source - ECI Study - 1997, with two years added to take into account germination time.

Discussion and Analysis

In the Boreal forest zone, poplar is typically the dominant species of brush. In addition poplar typically sprouts from the root, reducing germination time. In the other two zones, there usually are many species present.

Recommendation

It is recommended that the average brush control cycle, for planning purposes be 5.8 (6) years, recognizing in the north it could be longer, and in the south it could be shorter, based on condition assessments. A shorter cycle may be warranted on distribution right of ways in high visual profile areas. The NPV process supports the 5.8 year cycle.

Appendix E

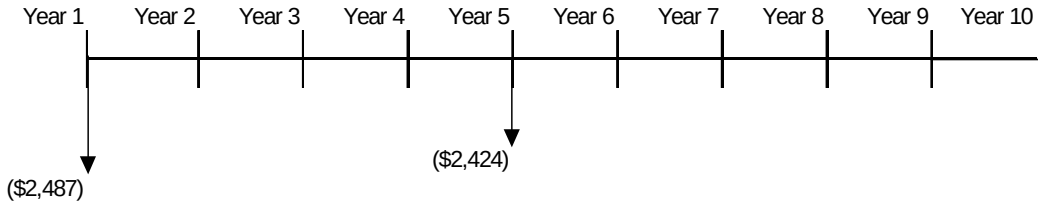
Ingrowth Retention vs. Traditional Clearing

The evaluation of the two alternatives concluded that traditional clearing is a better method than ingrowth retention and as a result any investment proposals for DM103 should not consider ingrowth retention. This conclusion was made based on the following:

Net Present Value (NPV):

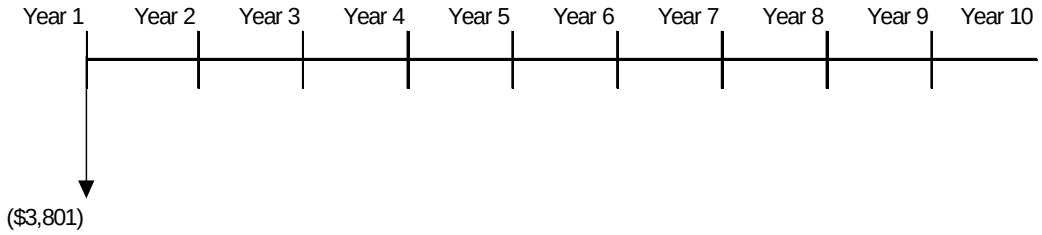
The NPV of traditional clearing is significantly less than that of ingrowth retention. This can be shown by the following cash flows that depict the costs associated with maintaining 1 km of line over 1 line clearing cycle. (The cycle used in the example is the current 10 year cycle.)

INGROWTH RETENTION



NPV (6.6% Discount Rate) = ($4,364)

TRADITIONAL LINE CLEARING



NPV (6.6% Discount Rate) = ($3,801)

The cash flows depicted above indicate that traditional line clearing is the preferred method because its NPV is less than that of ingrowth retention.

Reliability:

In the above cash flows, ingrowth retention required mid-cycle maintenance in year 5. This maintenance is necessitated by the fact that ingrowth retention does not prune every tree on the right of way and as a result leaves the system more susceptible to tree related outages. In order to mitigate the risk of outages, every route km where the ingrowth was left is revisited and trees that are contacting the line are pruned or removed. Despite the mid-cycle maintenance, ingrowth

retention poses more of a reliability risk than the traditional method and is therefore not preferred.

Ingrowth retention without mid-cycle maintenance was not considered because it presents a large reliability risk.

Other:

As a result of mid-cycle maintenance, the ingrowth retention method is more complicated and presents a greater number of logistical problems than the traditional method. Due to the fewer complications, the traditional method is preferred to the ingrowth retention method.

Filed: April 4, 2008
EB-2007-0681
Exhibit H-1-49
Attachment A
1 of 21

Vegetation Management Study

Mar. 4, 2003
(Recommendations on page 3 added October 12, 2005)

S.T. Griffiths, R.P.F.

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Tree Densities

Introduction

HydroOne's service area is, for the most part, located in rural Ontario, with a relatively low customer density and millions of trees. The forestry workload, and the number of tree caused power outages are directly influenced by the number of trees present in the vicinity of the power lines. The 1998 ECI study stated the tree density on Hydro One's distribution system is 62 trees per kilometre of line. Actual reported trees treated from 1998 - 2002 are less than 62 (most recently due to the ingrowth retention scheme). Lower tree density means lower tree-caused outages and less expensive line clearing, in the long term

Tree densities have increased over the past 15 years. Throughout the 1990's herbicide programs were virtually eliminated. In many locations, scheduled line clearing programs were replaced by "Hot Spotting", those areas in immediate need of treatment.

Recommendations (Added October 12, 2005)

Hydro One should assess different ways to significantly reduce the distribution forestry workload. Decreasing the time between successive treatments and increasing the tree removal rates will reduce future forestry workload, but there are additional means that can be employed to supplement the primary methods. The following recommendations are more administrative, innovative, and resource efficient:

1. **Maximizing efforts to retain the chemical option for brush control.** Develop centralized expertise who can react to all “local” situations that threaten this option. The selective chemical option is the single most effective tool to efficiently manage tree density. Many municipalities are enacting by-laws to restrict the use of herbicides for cosmetic use; the town of Huntsville and the district of Muskoka are currently debating the same type of bylaw. Hydro One should have a spokesman with a professional knowledge of this subject “on the ground” to spread the word of the importance of industrial herbicides for managing the “millions of stems of young forest type trees” that will threaten the reliability and security of the electric service, and the cost consequences to customers if this option is lost.

2. **Improve communications with customers regarding tree issues.** Rural Ontarians are more aware now than ever before the problems associated with trees and power outages. As a group, they should be more receptive to wider right of ways, the use of chemicals, more removals (when they are in the Company’s economic interest) because these initiatives will ultimately save them money. Also, Hydro One has recently acquired a number of urban utilities; communicating with them to not plant any trees near your lines makes sense. To summarize, the customers should not be part of the problem, but part of the solution. A forestry newsletter included with their bills and/or inserted in magazines directed to the customer base could be considered.

3. **Review the clearing specifications.** Are too many trees being treated, or the right species? Hydro One has come a long way in recording tree-caused outage information, but there is room for improvements; are there some tree species more liable to cause outages than others? A detailed analysis of tree caused outages can be fed back to clearing specifications, and these could vary for different parts of the province.

4. **Implement an auditing program** A forestry audit program is essential. Forestry managers are under pressure to meet production targets but are the jobs completed to specification? Forestry on the job performance, when a systematic auditing program is in place, tends to improve the product. The auditors, whether internal or external, should be trained and certified. There is a designated "Certified Environmental Auditor, Sustainable Forest Management" under the auspices of the Canadian Environmental Auditing Association. Internal professionals with this designation should be developed.

5. **Build Forestry Relationships with the Ontario Community.** Tree and wire conflicts are everyone's problem. Hydro One should be progressive and promote/establish relationships with provincial NGO's that comprise a significant portion of the customer base. Organizations such as the Ontario Forestry Association, the Ontario Woodlot Owners Association, the Federation of Ontario Cottagers Association, Ontario Federation of Agriculture etc. are, for the most part comprised of rural landowners with forest land. Active participation in these organizations and others could assist in communicating the "Tree message". Hydro One should have booths at fall fairs to promote the forestry message. This expertise could be acquired and trained, at minimal cost, utilizing university or community college students from forestry/biology programs. This message should typically include the importance of herbicides for Hydro One and no trees near powerlines.

Dx Line Clearing Cycles

Introduction

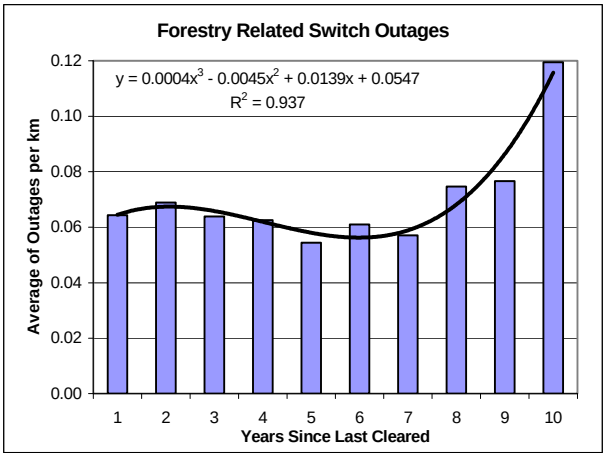
The Hydro One distribution system is comprised of 100,000 route km of overhead lines. At the present time the tree clearing cycle is approximately 10 years. Neighbour utilities maintain their lines every 5 to 7 years. Due to the vegetation conditions prevalent in the service area, 6 to 8 years clearance can be obtained (less in built up areas) utilizing acceptable arboricultural techniques. After these times vegetation grows into the conductors, increasing the clearing costs, risks and number of tree-caused outages.

Tree growing conditions vary throughout Ontario, which is divided into three forest zones, each featuring different types of trees and growing conditions. Trees in the southern (Carolinean) zone grow faster than those in the north (Boreal) zone with those in the central (Great Lakes St. Lawrence) zone in between. Different growth rates are discussed under brush control. The following rationale provides a business case for decreasing the clearing cycle.

System Reliability / Tree-caused Outages

Analyses of primary forestry related outages compared to when the lines were cleared identified that the number of outages per kilometre of line more than doubled 10 years after clearing compared to 7years after clearing. Over the 5 year planning period, $15,000,000 could be saved in trouble response with a 7 year average clearing cycle compared to the current 10 year cycle.

Chart 1: Forestry outages and years since last cleared



This is discussed in greater detail in **Appendix A**.

Financials

Four different funding levels were assessed for "Before tax net present values" (NPVs). The results are shown in table 1, below.

Table 1: NPV Analysis for each of the investment proposals

Funding Level	Investment Proposals		Before Tax NPV ($M)		
	Line Clearing	Brush Control	Line Clearing	Brush Control	Total
Minimum	10 Year	10 Year	(859)	(200)	(1,060)
Level 1	9.3 Year	6.8 Year	(868)	(187)	(1,054)
Level 2	8 Year	6.8 Year	(872)	(187)	(1,058)
Level 3	7 Year	5.8 Year	(885)	(185)	(1,070)

The NPV's were calculated over a 20 year period. Although the unit costs for line clearing decrease with shorter cycle intervals, the increased costs of reducing the cycles over the first few years overcompensates for reduced unit costs later on, so the lower cycles in Levels 2 and 3 do not have lower NPV's over the 20 year period. The detailed NPV's for the 4 funding levels are in Appendix B.

Discussion

The NPV's for the various funding levels are relatively close over the study period. Shorter brush control cycles feature lower NPV's while shorter line clearing cycles have higher NPVs. The line clearing cycles are driven by reliability and customer perception. Data shows that outages per kilometre double in years 7 through 10 of a line clearing cycle, and though there is no supportive data available, Chart 1, above suggests an exponential increase in outages beyond year 10. Customer perception is difficult to assess, but interviews with selected external customers and Hydro One customer service staff conclude there is an increasing perception that electrical service is deteriorating and trees are a major reason.

Recommendation

The ideal cycle for line clearing is 7 years, and Level 3 funding is recommended. A 7 year average cycle represents the maximum clearance that field workers can reasonably expect to attain with our growing conditions. Tree caused outages rapidly escalate after 7 years.

Dx Brush Control Cycles

Introduction

Most of the land associated with HydroOne's distribution system is capable of supporting woody vegetation that will grow into the conductors if not effectively managed. The brush must be controlled to prevent it from growing into the lines and causing outages, and to facilitate access for maintenance and repair. Government approved herbicides, applied selectively, is the preferred and most efficient brush control option.

Financials

Three different cycle scenarios were assessed for the four investment proposals: 10 years, 6.8 years and 5.8 years. Unlike line clearing, the shorter the cycle, the lower the NPV, as noted below:

Table 2

Brush Control	Brush Control NPV
10 Year	(200)
6.8 Year	(187)
6.8 Year	(187)
5.8 Year	(185)

Discussion

The methods and timing of controlling brush significantly impact the costs associated with the activity. A selective application of herbicide is the most efficient way of controlling brush. Repeated applications over succeeding cycles reduce the brush density (and subsequent future expenditures). To accomplish this, the brush must be retreated before it retains a height of 3 metres. If the brush is allowed to grow beyond 3 metres, more costly removal techniques must be employed. The schematic "Cost to Treat Trees/Brush Based on Height", below depicts the cost of treating various heights of brush and trees.

As was stated above, the growth of brush varies by location in the province, and, since there are identifiable height levels that are significant in terms of escalating cost thresholds, predictions can be made on establishing cost effective cycles. This is described in Brush Control, Optimum Cycles, **Appendix C.**

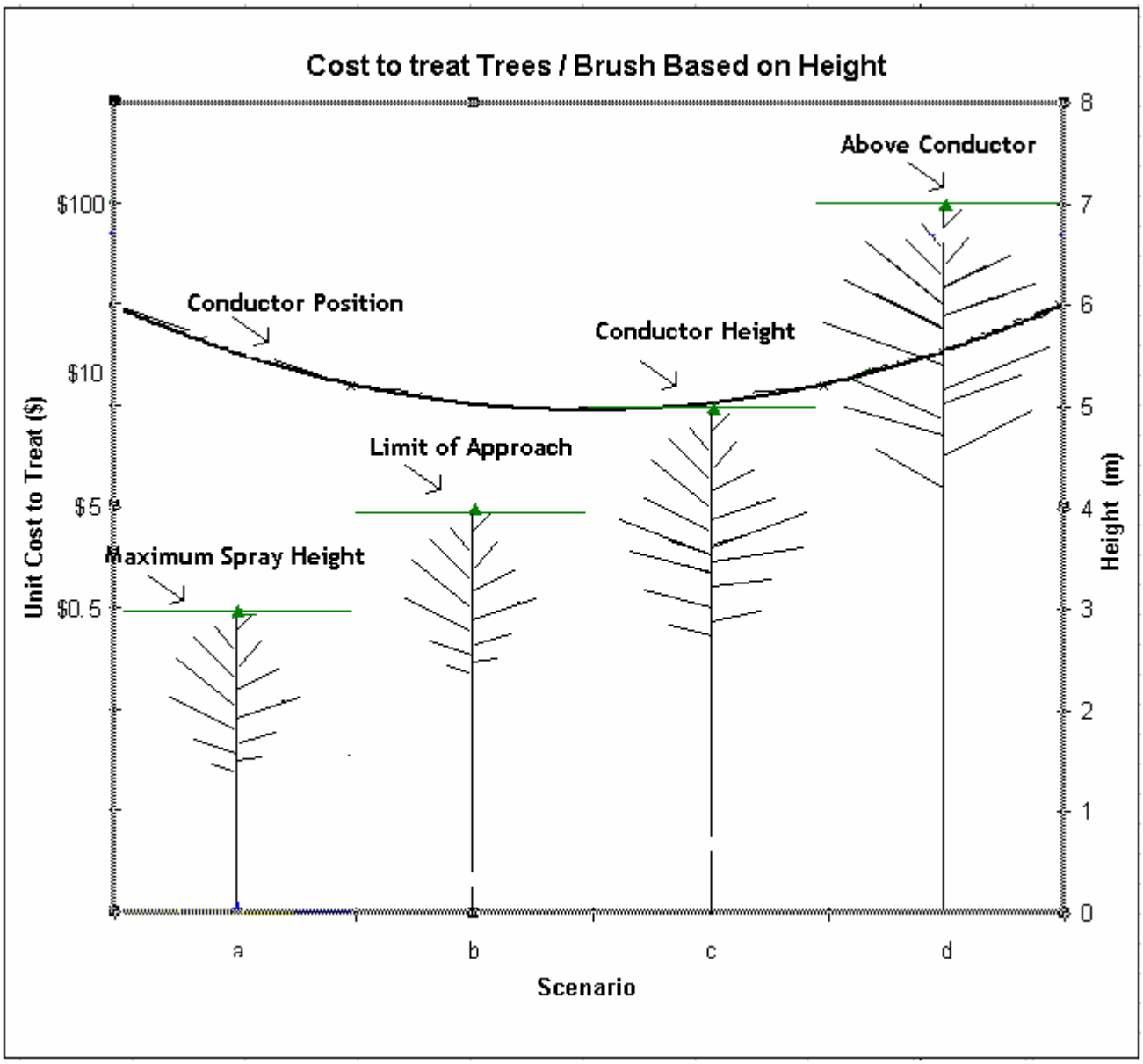


Chart 2

a Brush up to 3 metres tall, cost $0.50 to treat (Average age – 7 years)

b Brush over 3 metres but outside of limit of approach to energised conductor, cost $5.00 to cut, remove and pile/chip (Average age – 10 years)

c Brush within limit of safe approach to conductor, must remove with qualified personnel using live line tools. Cost to remove $10.00. (Average age – 12 years)

d A tree (classified as over 10 cm measured at breast height) Cost to remove: over $100.00.

Ingrowth Retention

Introduction

Tree branches have been left untreated at certain locations on single phase pole top pin construction since year 2000. This "Ingrowth" retention system was implemented to improve forestry line clearing production. Basically tree branches that are not into the line are not treated even if they will be over the next cycle. When the decision was implemented to allow the ingrowth, full life cycle costs were not available.

Discussion and Analysis

There are approximately 59,000 km of single phase line in Hydro One's system. Of that total, it is assumed that 40,000 km is eligible for the ingrowth retention system, the balance being crossarm construction or single phase in "public areas" that is treated normally. Single phase voltages range from 2.4 kv up to 16 kv. Although there have not been any detailed performance analyses undertaken, it is expected that the performance of the higher voltage single phase lines will deteriorate more rapidly.

The ingrowth retention system does not reduce tree density as trees are left untreated that would be cleared under normal circumstances. The greater the tree density, the higher number of outages.

The NPV's of the ingrowth retention and traditional line clearing system were compared. Based on this comparison, which included a mid cycle treatment for the ingrowth retention system, the traditional method has a lower NPV. This is further described in **Appendix E.**

Recommendation

Based on the preceding discussion and **Appendix E,** the ingrowth retention scheme should be abandoned, and replaced by a standard specification featuring cycle clearance.

Forestry Map Scaling Project

Description of Project

Forestry reports work accomplishment on a "route kilometre (km) basis". Double circuit lines and overbuild/underbuild are only counted once. There was uncertainty on the actual amount of distribution lines, so for planning purposes, all the route kms of lines were map scaled. The work was carried out by lines zone and operating centre.. The first step was to identify all the overbuild (subtransmission) on the primary distribution maps, so route line kilometres were only counted once. Double circuit lines were also only counted once. Since each feeder was being scaled, submarine and underground km were included, for use by other groups. Attempts were made to identify on / off road situations, and locations inaccessible to mechanized equipment. A tabular summary of the project by forestry district follows in Table 3. This updated information is being added to a revised forestry database.

Table 3 Forestry Scaling Project, 2002

District	multi phase km	single phase km	total km*	LV	Primary Dist	Urban km	Long cy km
1	7637	10206	17843	3733	14110	1600	12510
2	4631	7350	11980	1377	10603	1490	9113
3	2558	2379	4937	1424	3513	603	2910
4	2274	3288	5562	791	4772	449	4323
5	2749	3084	5833	765	5068	778	4290
6	2450	3005	5455	749	4706	580	4126
7	2467	4134	6601	653	5948	694	5254
8	3876	5964	9840	899	8941	1066	7875
9	1766	3234	5000	486	4514	708	3806
10	1384	3594	4978	342	4636	597	4039
11	1233	2671	3904	357	3546	81	3465
12	832	1243	2075	269	1806	265	1541
13	1818	2166	3983	389	3595	211	3384
14	2727	1967	4695	1115	3580	334	3246
15	1215	1849	3064	717	2347	64	2283
16	1238	2587	3825	131	3694	97	3597
Totals	40854	58722	99576	14197	85378	9617	75762

*Double circuit counted once; underbuild counted to highest voltage
Includes primary distribution and low voltage to 44kv

Recommendations

1. Utilize updated information for planning purposes.
2. Validate and revise database as new feeder information becomes available.

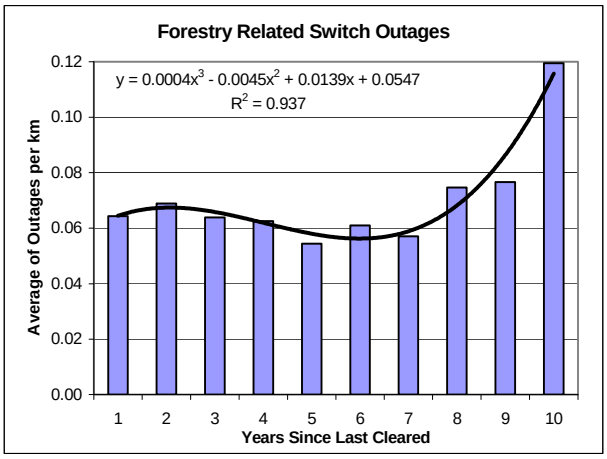
Appendix A

DM103 Attachment - Distribution Vegetation Management

1) Impact on Other Business Drivers

Vegetation management activities under DM103 have the potential to greatly impact the number of outages experienced by the Hydro One's distribution system. As a result, work achieved under this driver will affect Trouble Call and Storm Damage Restoration expenditures under DM101 and DC106.

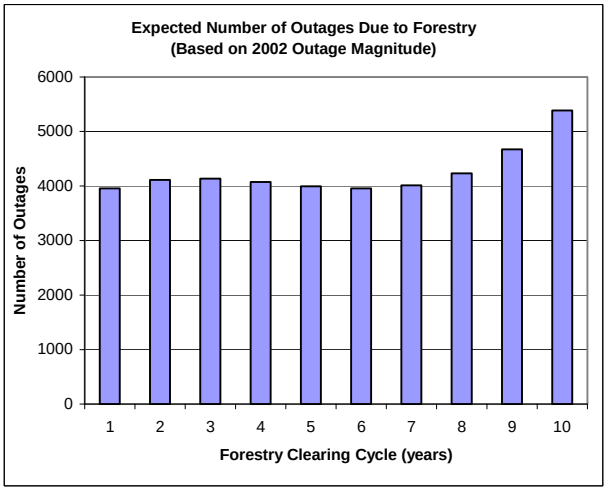
Chart 3: Expected Number of Forestry Related Switch Outages per km for HONI feeders cleared.



To assess the impact that vegetation management activities have on other drivers, the relationship between the number of outages and the tree clearing cycle used on HONI feeders was established. **Chart 3** to the left displays this relationship for feeders that were cleared during the past 10 years. For example, the average HONI feeder that was cleared 1 year ago can expect to have approximately 0.065 forestry related switch outages per km this year.

Switch Outages depending on the line clearing cycle.

Chart 4: Expected Number of Forestry Related



Using the relationship developed in **Chart 3** above, the number of outages that would be expected across the entire system can be predicted. **Chart 4** to the left shows the estimated number of forestry-related switch outages that can be expected for clearing cycles between 1 and 10 years.

Currently, the HONI system is assumed to be on a 10 year clearing cycle and is experiencing approximately 5300 forestry-related switch outages. **Table 4** below shows how a shorter forestry line clearing cycle would affect the number of outages experienced on the HONI system.

Table 4: Savings based on outage reductions as a result of shorter line clearing cycles.

Funding Level	Cycle (years)	Outage Savings per year	Incremental Outage Savings in year 1	Outage Savings in Planning Period: years 1 – 5	$M Savings in Planning Period: years 1- 5
Minimum	10	0	0	0	$0
Level 1	9.3	500	54	810	$4.1
Level 2	8	1,200	150	2,250	$11.3
Level 3	7	1,400	200	3,000	$15.0

The monetary savings quoted in **Table 4** above are based on the outage savings and on the approximate 2002 expenditure of $5000 per forestry related outage. It is concluded that vegetation management activities have the potential to save trouble call and storm damage expenditures (DM101 and DC106) between $0 and $15.0 million dollars depending on the funding level selected.

2) Financial

The following notes are relevant to the financial assessment of the investment proposals:

- The current forestry cycle is assumed to be approximately 10 years.
- The current vegetation condition was predetermined through past maintenance practices and is based on available information.
- It is difficult to relate the current system condition to an equivalent maintenance cycle as substantial hot spotting in past years makes it difficult to relate overall condition to a specific cycle.
- Unless improvements are made, it is expected that the forestry condition will deteriorate over the business planning period as a result of past maintenance practices.

Taking into account the above notes, the financial assessment estimated the expenditures associated with each of the investment proposals. Using these estimates over a 20-year planning period, **Table 5** below was constructed to illustrate the net present values at each funding level.

Table 5: Net Present Value (NPV) Analysis for each of the investment proposals.

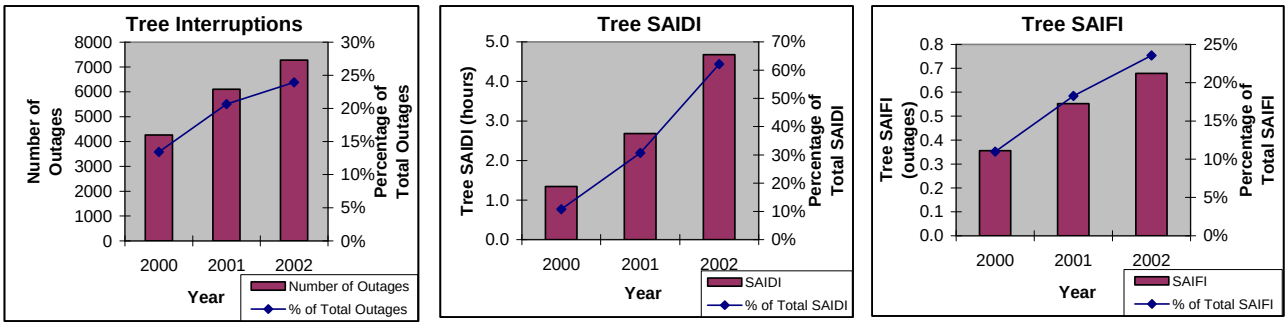
Funding Level	Investment Proposals		Before Tax NPV ($M)		
	Line Clearing	Brush Control	Line Clearing	Brush Control	Total
Minimum	10 Year	10 Year	(859)	(200)	(1,060)
Level 1	9.3 Year	6.8 Year	(868)	(187)	(1,054)
Level 2	8 Year	6.8 Year	(872)	(187)	(1,058)
Level 3	7 Year	5.8 Year	(885)	(185)	(1,070)

The net present values in the above table indicate that in the long term, financial differences between the investment proposals are negligible. These values are dominated by short-term (1-7 years) expenditures required to move from one cycle to the next.

3) Customer Reliability (Sensitivity Analysis)

Reliability data from 2000-2002 has shown that forestry interruptions have increased at a significant rate and that they are making larger contributions to overall SAIDI and SAIFI values. The charts included under Chart 5below illustrate this alarming trend.

Chart 5: Reliability trends over the years 2000 – 2002.



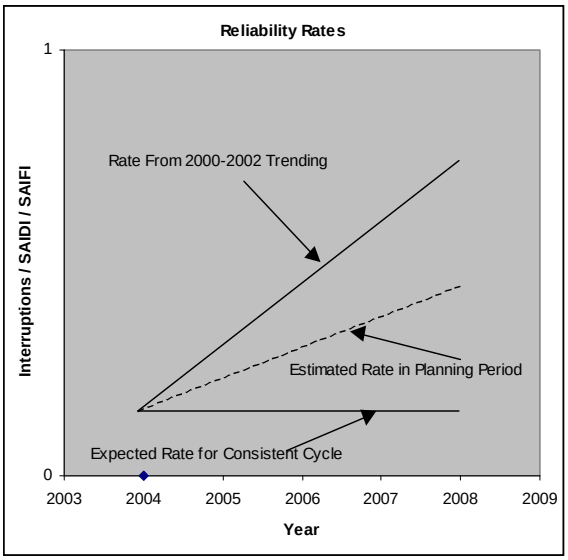
At the current pace, the trends illustrated in **Chart 5** above show that the HONI system can expect an increase of at least (minimum of the last two years:

- 1200 tree interruptions per year
- 1.3 hours per year to SAIDI

- 0.1 interruptions per year to SAIFI

Increases in tree related interruptions, SAIDI, and SAIFI should naturally stop as a given line clearing cycle is adopted and implemented over a consistent period of time. Currently, the line clearing cycle is approximated at 10 years, but historic fluctuations in the work program have impeded the reliability metrics from reaching a plateau. To evaluate the investment proposals, the assumption was made that the rate of reliability deterioration over the planning period will be between zero (a plateau has been reached) and the current trends identified above. In general terms, Chart 6 below illustrates the estimation made.

Chart 6: Illustration of rates of increase for reliability indices.



Using the estimation illustrated in **Chart 6** to the left, the following rates of increase were determined for the current 10-year clearing cycle (corresponding to the minimum funding level):

- 500 tree interruptions per year
- 0.55 hours per year to SAIDI
- 0.04 interruptions per year to SAIFI

(These rates were derived using a 20% reduction for better reporting and assuming that over the planning period the rate will on average fall half way between the two extremes illustrated.)
Table 6 below shows how the minimum funding level will impact the reliability indices based on these rates.

Table 6: Reliability improvements at different points in the planning period.

Funding Level	Cycle (years)	Outage Rate (outages/year)	Outage Increase: Year 5 Outages – Year 0 Outages	SAIDI Rate (hours/year)	SAIDI Increase: Year 5 SAIDI – Year 0 SAIDI	SAIFI Rate (outages/year)	SAIFI Increase: Year 5 SAIFI – Year 0 SAIFI
Minimum	10	500	2,500	0.55	2.75	0.04	0.20

For funding levels other than the minimum, these rates will be less since a shorter cycle will reduce the number of tree related interruptions. Nevertheless, the potential for reliability deterioration under Levels 1,2, and 3 could exceed 0.2 hrs for SAIDI, and as such falls in the Major category with different probabilities for the different funding levels.

Appendix B: Net Present Value (NPV) Calculations

Minimum

10 Year Line Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)	(37,395)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)
Customer Contact	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)	(4,420)
Tree Related Reliability Cost	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)	(25,637)
NPV	**(73,757)**	**(69,191)**	**(64,907)**	**(60,888)**	**(57,119)**	**(53,582)**	**(50,265)**	**(47,153)**	**(44,233)**	**(41,495)**	**(38,925)**	**(36,515)**	**(34,255)**	**(32,134)**	**(30,144)**	**(28,278)**	**(26,527)**	**(24,885)**

10 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)	(14,620)
Customer Contact	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)	(2,120)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(17,205)**	**(16,140)**	**(15,141)**	**(14,203)**	**(13,324)**	**(12,499)**	**(11,725)**	**(10,999)**	**(10,318)**	**(9,679)**	**(9,080)**	**(8,518)**	**(7,990)**	**(7,496)**	**(7,032)**	**(6,596)**	**(6,188)**	**(5,805)**

Level 1

9.3 Year Line Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(41,720)	(39,918)	(39,723)	(39,528)	(39,334)	(39,139)	(38,944)	(38,750)	(38,555)	(38,360)	(38,166)	(37,262)	(37,262)	(37,262)	(37,262)	(37,262)	(37,262)	(37,262)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)	(4,722)
Tree Related Reliability Cost	(25,378)	(25,119)	(24,860)	(24,600)	(24,341)	(24,082)	(23,823)	(23,564)	(23,304)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)	(23,226)
NPV	**(78,791)**	**(71,979)**	**(67,123)**	**(62,593)**	**(58,366)**	**(54,422)**	**(50,744)**	**(47,312)**	**(44,110)**	**(41,226)**	**(38,571)**	**(35,735)**	**(33,523)**	**(31,447)**	**(29,500)**	**(27,674)**	**(25,961)**	**(24,353)**

6.8 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(18,297)	(17,380)	(16,462)	(14,942)	(14,040)	(13,305)	(12,193)	(11,926)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(21,549)**	**(19,354)**	**(17,348)**	**(15,019)**	**(13,391)**	**(12,027)**	**(10,525)**	**(9,703)**	**(7,846)**	**(7,360)**	**(6,904)**	**(6,477)**	**(6,076)**	**(5,700)**	**(5,347)**	**(5,016)**	**(4,705)**	**(4,414)**

Level 2

8 Year Line Clearing Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(46,091)	(45,408)	(44,724)	(44,041)	(42,602)	(41,414)	(40,501)	(39,588)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)	(38,517)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)	(5,479)
Tree Related Reliability Cost	(24,944)	(24,250)	(23,557)	(22,863)	(22,169)	(21,476)	(20,782)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)	(20,088)
NPV	**(83,485)**	**(77,025)**	**(71,044)**	**(65,509)**	**(59,801)**	**(54,224)**	**(49,771)**	**(45,663)**	**(42,194)**	**(39,581)**	**(37,131)**	**(34,832)**	**(32,675)**	**(30,652)**	**(28,754)**	**(26,974)**	**(25,304)**	**(23,737)**

6.8 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(18,297)	(17,380)	(16,462)	(14,942)	(14,040)	(13,305)	(12,193)	(11,926)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)	(9,831)
Customer Contact	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)	(2,786)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(21,549)**	**(19,354)**	**(17,348)**	**(15,019)**	**(13,391)**	**(12,027)**	**(10,525)**	**(9,703)**	**(7,846)**	**(7,360)**	**(6,904)**	**(6,477)**	**(6,076)**	**(5,700)**	**(5,347)**	**(5,016)**	**(4,705)**	**(4,414)**

Level 3

7.1 Year Line Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Line Clearing	(51,581)	(50,449)	(48,589)	(46,489)	(44,976)	(41,826)	(40,009)	(38,309)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)	(37,428)
Customer Requests	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(2,160)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)	(1,460)
Customer Contact	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)
Unplanned	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)	(1,800)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
Ingrowth Retention Adjustment	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)	(6,175)
Tree Related Reliability Cost	(24,694)	(23,751)	(22,808)	(21,865)	(20,922)	(19,979)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)	(19,036)
NPV	**(89,904)**	**(82,392)**	**(74,823)**	**(67,679)**	**(61,587)**	**(54,800)**	**(49,049)**	**(44,926)**	**(41,616)**	**(39,039)**	**(36,622)**	**(34,355)**	**(32,228)**	**(30,233)**	**(28,361)**	**(26,605)**	**(24,958)**	**(23,412)**

5.8 Year Brush Clearing Cycle

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brush Clearing	(20,881)	(19,146)	(15,898)	(13,769)	(12,553)	(9,930)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)	(9,252)
Customer Contact	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)	(3,269)
Customer Requests	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)	(240)
Asset Condition Assessment	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)	(225)
NPV	**(24,615)**	**(21,463)**	**(17,276)**	**(14,449)**	**(12,613)**	**(9,926)**	**(8,850)**	**(8,302)**	**(7,788)**	**(7,306)**	**(6,853)**	**(6,429)**	**(6,031)**	**(5,658)**	**(5,307)**	**(4,979)**	**(4,670)**	**(4,381)**

Appendix C

Internal and External Communication

Introduction

The scope and magnitude of Hydro One's forestry activities create an impact on the province of Ontario. Every year the vegetation on thousands of hectares/kilometers is treated to maintain a secure supply of product, and reduce the risks of personal injury. There are various types of communication that take place during the execution of Hydro One's forestry programs (routine line clearing, brush control, stakeholder requests and emergency [storm] repair). These include external (stakeholders outside the company) and internal communication (contacts within the company necessary to carry out the programs). Inefficient or incomplete means of communication can cause expensive delays and/or interruptions to the programs.

Discussion and Analysis

Effective communication is required to ensure the work is carried out in an efficient manner. The very nature of the vegetation management activity can provoke a negative response from the customer (for example wanting to remove a significant portion of a shade tree on his front lawn or using herbicides to control brush). There is a process in place with Customer Relations to handle forestry related complaints.

Types of Forestry Communication

1. Internal

Communication between the various internal groups:

- Planning to Execution to Doers, three groups decide on objectives, targets and programs to achieve objectives; verified by audits, performance data; Services back to Planning.
- The Customer Care Centre, after receiving an external forestry call, to either forestry operations support staff or to customer relations, if the external call is a complaint.

2. External

There are various forms of external stakeholder interface with Hydro One's forestry programs:

A. Providing External Communication

1. Customer/landowner notification - Hydro One makes a routine attempt to notify every landowner/customer of pending forestry activities.
2. General public - Hydro One periodically provides proactive information to the general public on matters that can have an impact on forestry programs. Examples are:
   - Bill stuffers providing where to plant/not to plant info (with respect to overhead and underground plant).
   - Magazine/newspaper advertisements identifying risks due to trees and power lines

3. Specific Stakeholders - Hydro One will react to landowner/customer concerns about a planned or current forestry activity. This reaction usually takes place by:
   - Personal contact either in person or by phone in response to a query/complaint
   - Meeting with a group of customers/stakeholders to explain a forestry activity about to be carried out.
4. Regulators - applying for C. of A.'s and permits as required. (MNR and MOE)
5. Suppliers

B. Receiving External Communication

1. Customer/landowner query about:
   - Existing tree/vegetation conditions, including loss of power
   - Current forestry activity taking place
2. Group (municipality/ratepayer/cottage association)
   - Questioning specific maintenance practices
3. Regulators - C. of A., and permit approvals, violations
4. Other government (politicos)

Recommendations

1. All customer/landowner queries received should be logged by location/feeder to assist management in assessing the overall effectiveness of the forestry program.
2. Staff in the Customer Relations Centre be provided with current, approved forestry policies and procedures to assist in dealing with customers. (This has been informally done)
3. The Company should develop and implement strategies to ensure the most efficient vegetation techniques are retained or even enhanced.
4. Internal communication procedures should be implemented amongst the planning, program and services groups so required information is available in a timely manner.

Appendix D

Brush Control, Optimum Cycles

Introduction

Brush (young forest type trees) typically invades power line right of ways and, if left unmaintained, will grow into the conductors. Selective herbicide applied by ground crews is the preferred control option for treating brush, as this option leaves the dead brush standing eliminating disposal costs and reduces the number of tree stems over successive cycles. The optimum cycle is the one that has the lowest net present value. The main determining factor is brush height. The maximum brush height for herbicide application by ground crews is 3 metres to ensure complete coverage and efficient use of herbicide. Another reason to limit the brush height to 3 metres is the visual impact created by foliar applications. Significant financial penalties are incurred if the brush is allowed to grow above 3 metres, as noted in **Appendix B**.

Different species of brush exhibit different growth rates, and Ontario is divided into three forest type zones, determined by climate (growing season). Typical species found on right of ways in the different zones and the number of years to attain 3 metres are:

Table 7, Main brush species, and time to attain 3 metres

Forest Zone	Growing season (days)	Brush type	# years to attain 3 metres *
Boreal (north)	150-180	Poplar spp	7
		Spruce, black & white	13
		Balsam fir	13
		White birch	9
		Jack pine	13
Great Lakes - St. L	180-190	Maple spp	6
(Central)		White ash	6
		White pine	8
		Poplar spp	7
		Red oak	9
		White birch	9
Carolinian (South)	200-220	Maple spp	6
		White ash	6
		White elm	6
		Black walnut	6

* Data source - ECI Study - 1997, with two years added to take into account germination time.

Discussion and Analysis

In the Boreal forest zone, poplar is typically the dominant species of brush. In addition poplar typically sprouts from the root, reducing germination time. In the other two zones, there usually are many species present.

Recommendation

It is recommended that the average brush control cycle, for planning purposes be 5.8 (6) years, recognizing in the north it could be longer, and in the south it could be shorter, based on condition assessments. A shorter cycle may be warranted on distribution right of ways in high visual profile areas. The NPV process supports the 5.8 year cycle.

Appendix E

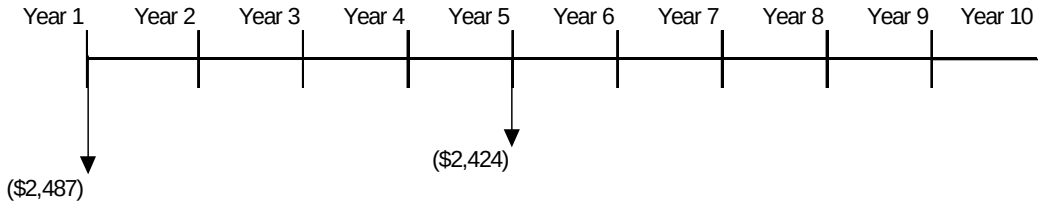
Ingrowth Retention vs. Traditional Clearing

The evaluation of the two alternatives concluded that traditional clearing is a better method than ingrowth retention and as a result any investment proposals for DM103 should not consider ingrowth retention. This conclusion was made based on the following:

Net Present Value (NPV):

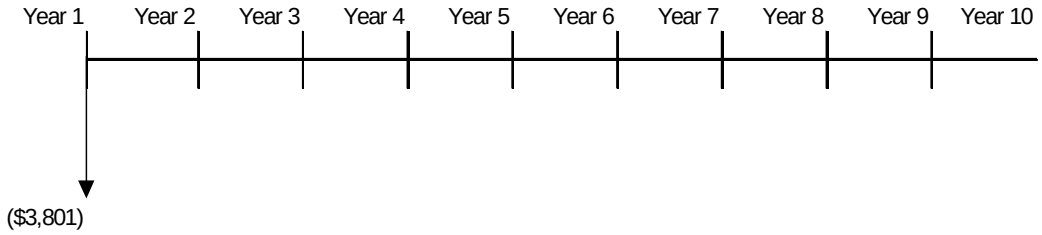
The NPV of traditional clearing is significantly less than that of ingrowth retention. This can be shown by the following cash flows that depict the costs associated with maintaining 1 km of line over 1 line clearing cycle. (The cycle used in the example is the current 10 year cycle.)

INGROWTH RETENTION



NPV (6.6% Discount Rate) = ($4,364)

TRADITIONAL LINE CLEARING



NPV (6.6% Discount Rate) = ($3,801)

The cash flows depicted above indicate that traditional line clearing is the preferred method because its NPV is less than that of ingrowth retention.

Reliability:

In the above cash flows, ingrowth retention required mid-cycle maintenance in year 5. This maintenance is necessitated by the fact that ingrowth retention does not prune every tree on the right of way and as a result leaves the system more susceptible to tree related outages. In order to mitigate the risk of outages, every route km where the ingrowth was left is revisited and trees that are contacting the line are pruned or removed. Despite the mid-cycle maintenance, ingrowth

retention poses more of a reliability risk than the traditional method and is therefore not preferred.

Ingrowth retention without mid-cycle maintenance was not considered because it presents a large reliability risk.

Other:

As a result of mid-cycle maintenance, the ingrowth retention method is more complicated and presents a greater number of logistical problems than the traditional method. Due to the fewer complications, the traditional method is preferred to the ingrowth retention method.

Ontario Energy Board (Board Staff) INTERROGATORY #50 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 1 – Vegetation Management Program/ Issue 4.3

Hydro One quotes from page 31 at Exhibit C/Tab 2/ schedule 2 of its 2006 Distribution Rates application stating that, "Hydro One Distribution's goal is to continue to increase accomplishments for line clearing with an objective to reach an optimum cycle from a reliability perspective of eight years by 2008. Annual accomplishments would have to increase from the current 10,360 km to 12,500 km". In this application, Hydro One states that the proposed accomplishments for vegetation management are 12,500 km of rights-of-way line clearing and 12,500 km for brush control.

a. Please confirm if Hydro One's tree trimming cycle for 2007 was 11 years, as referenced by Hydro One Distribution Benchmarking Study dated October 24, 2007 that was conducted by PA Consulting Group, Page 4-21.
b. Please state if Hydro One has changed its 2008 tree trimming cycle to 8 years. If so, please provide the incremental cost for the acceleration in its tree trimming practice.

Response

a. The reference to an 11-year cycle in the Benchmarking Study is based on the actual accomplishments in 2006. In 2007, Hydro One's line clearing actual accomplishment was 12,211 km, which is just under the 12,500 km required for an 8-year cycle.

b. Hydro One is proposing an 8-year cycle in 2008 and a proposed expenditure of $119.4 million, which is an increase of $5.3M over 2007 spending.

Ontario Energy Board (Board Staff) INTERROGATORY #51 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 2,– Vegetation Management Program and Exhibit A Tab 15 Schedule 1 – Service Reliability Indicators/ Issue 4.3 and Issue 1.6

On page 30 of Exhibit C1 Tab 2 Schedule 2, Hydro One states: "The 2008 spending on the vegetation management program is $119.4 million, which is about 35% greater than average historic expenditures". Hydro One further states on page 31, "As noted in section 6 of Exhibit A, Tab 3, Schedule 1, tree-related contacts accounted for 57% of SAIDI and 28% of SAIFI between 2003 and 2006, and the negative impact of trees during storm events were especially acute. As such, vegetation management presents the greatest opportunity to improve reliability."

a. Please state if the proposed 2008 spending on the vegetation management, which is 35% greater than average historic expenditures, is expected to improve reliability performance in 2008 and beyond. If so, please provide an explanation of why Hydro One has established 2008 targets for the SAIFI, SAIDI, and CAIDI that are the same as 2006 targets, as shown in Table 2 of Exhibit A Tab 15 Schedule 1. Please provide Hydro One's views, in light of its proposed significant increase in vegetation management expenditures that should decrease the incidence and/or severity of outages from tree contacts, which in turn represent a significant proportion of the outages reflected in SAIDI and SAIFI, as to whether its operational targets for SAIDI and SAIFI in 2008 and beyond should be better (i.e. lower quantitatively) than in recent years.
b. Please describe Hydro One's enhancements to its vegetation management program and how Hydro One believes that these will result in the greatest opportunity to improve reliability. Please clarify how improvement in reliability would be reflected in operational targets for SAIDI and SAIFI in 2008 and beyond.

Response

a. Hydro One's 2008 Vegetation Program Planning Review, provided as an attachment to interrogatory response Exhibit H, Tab 1, Schedule 14 found that implementing an 8-year vegetation maintenance cycle improves tree related reliability by above 15% to 20% which improve SAIDI by about 0.9 hours and SAIFI by about 0.1 interruptions from current, average levels.

The 2008 targets referenced in Table 2 of Exhibit A, Tab 15, Schedule 1 are "OEB Targets", not operational targets, as discussed in the interrogatory response at Exhibit H, Tab 1, Schedule 53.

b. Hydro One's analyses of reliability performance, contained in the figures on pages 18 and 19 of Exhibit A, Tab 3, Schedule 1 illustrate that "Tree Contacts" are the greatest contributor to unreliability. As a result, Hydro One has determined that the greatest opportunity for improving reliability performance is to improve the Vegetation Management Program by reducing the cycle time. Cycle time reductions are expected to yield the improvements contained in part a) above. These benefits will be realized after a full cycle (i.e. 8 years) of vegetation maintenance is complete. In 2008, material improvements to reliability are not expected as this is the onset of an 8 year cycle. All things considered equal, some improvements are expected part way through the cycle, but the year to year correlation to reliability and level of work is not always consistent, as reliability of the distribution system is highly influenced by the number and severity of storms that occur each year. Hydro One expects that long term improvements in reliability as a result of increased vegetation management expenditures will contribute to its strategic objective of becoming a "top quartile" performer in reliability by 2010.

Ontario Energy Board (Board Staff) INTERROGATORY #52 List 1

Interrogatory

Ref: Exhibit D1 Tab 3 Schedule 5 – IT Capital Expenditure and Exhibit A Tab 15 Schedule 1 – Service Reliability Indicators/Issue 4.2 and Issue 4.8

The capital expenditure for IT development projects increased by 576% from 2006 ($12.5 million) to 2007 ($84.5 million) and by 449% in 2008 ($68.6 million) compared to 2006.

a. Please describe the 2007 and 2008 IT development projects, if any, that are **directly** attributed to enhancing Hydro One's reliability performance. Please provide the information for the project cost, cost as a percentage of IT capital expenditures, and implementation timelines.
b. If no IT development project is attributed directly to improving system reliability (e.g. enhancement of SCADA and control center, Outage management program, communications with the field devices such as RTUs and protection relays, etc), please state why Hydro One is not planning any investments in 2008 in its **IT infrastructure that directly support its system reliability**.
c. With respect to its total capital expenditures, (for example, as listed in its capital expenditure program proposed for 2008 in Exhibit D1 Tabs 2 and 3), please outline all 2004 to 2007 actual and 2008 projected capital expenditures that have been implemented, or planned for 2008, to **directly enhance Hydro One's reliability performance**. Please provide a description of each program with associated costs and implementation timelines in a tabular format.
d. Please provide the detail for Hydro One's storm management program, if any, stating if this program utilizes software programs residing on Hydro One's control system and SCADA and establishes communications with the field devices and field crews. Please provide information on IT upgrades for 2006-2008, if any, including costs and implementation timelines to further support this program. If Hydro One does not deploy a storm management program integrated into or with its SCADA system, please provide how Hydro One manages storms impacting its system infrastructure and service to customers.
e. Please provide detail on Hydro One's distribution automation (DA) programs for 2006-2008, if any, including description of each program, its cost, and implementation timelines in a tabulated format.

Response

a. There are no projects in the IT Capital program, Exhibit D1, Tab 3, Schedule 5, that have been specifically designed to improve reliability. The development projects identified in question b) of this Interrogatory would be identified under Operations Capital, Exhibit D1, Tab 3, Schedule 4, or under the Development Capital, Exhibit D1, Tab3, Schedule 3.

b. As noted in part (a), the type of projects referred to in this question are included under the Operating and Development Capital Programs. Within the context of the reliability initiatives identified in this question, Hydro One is planning investments in 2008 and beyond to directly support improvements to system reliability. The Distribution Development program, Exhibit D1 Tab 3 Schedule 4 Section 2.2.2, describes the work to install Distribution Station (DS) monitoring in strategic locations. The Operating Capital program, Exhibit D1 Tab 3 Schedule 3 Section 3.2, describes the initial steps being planned to interface the Smart Meters to the Outage Response Management System. Section 3.4 of the same exhibit describes the plan to enhance the Network Management System at the OGCC, which is today only used for monitoring and control of the Transmission System, so that it can interface with the sectionalizers and the devices being installed for monitoring of DS's.

c. Much of Hydro One's Sustaining Capital is directed at maintaining and enhancing reliability. As stated in Exhibit D1, Tab 2 , Schedule 3, line 12 to 16, "Investments covered under the Sustaining Capital program are proposed … to provide a level of reliability that is aligned with corporate objectives". On page 2 of that Exhibit, it goes on to say that assets are identified as candidates for replacement based on asset condition, historic performance, asset criticality, availability of spare equipment, customer impacts, and the business drivers which includes reliability as measured by SAIDI and SAIFI. All of these factors relate to reliability in some degree, but in most cases, address reliability from a longer term perspective to ensure reliability does not deteriorate. The program descriptions in Exhibit D1, Tab 3, Schedule 2 describe the Sustaining Capital programs in more detail.

With respect to Development Capital, there are some expenditures made in conjunction with development projects to replace assets due to reliability risks, but reliability is not the prime driver of the investment. However, there are specific Development Capital Projects directed at enhancing short term reliability, specifically to install sectionalizers and Distribution Station (DS) monitoring in strategic locations as described on pages 9-10 of Exhibit D1, Tab 3, Schedule 3 and in IJD D3 contained in Exhibit D2, Tab 2, Schedule 3. These initiatives change the operating characteristics of the existing system and provide shorter term reliability improvements. Spending for these programs is as follows:

2005 - $0.6 million
2006 - $2.4 million
2007 - $2.7 million
2008 - $3.1 million (planned).

d. Hydro One's storm management program is the Outage Response Management System (ORMS). Please see the interrogatory response in Exhibit H Tab 1 Schedule 54 for a high level description of the functionality of ORMS. Enhancements and periodic upgrades to ORMS are funded under the Operations Capital program. Between 2006 and 2008, $2.7M was spent on the version upgrade to ORMS. A further $1.7M was spent in 2007 upgrading the infrastructure supporting the ORMS system to improve its performance and reliability.

e. As described in the response to part (b), Hydro One's distribution automation programs consist of the installation of sectionalizers at strategic locations along certain feeders and adding monitoring to selected heavily loaded Distribution Stations. In 2008 $2.2 million will be spent on sectionalizers (for further details refer to the IJD D3 contained in Exhibit D2, Tab 2, Schedule 3) and $0.9 million will be spent on Distribution Station monitoring.

Ontario Energy Board (Board Staff) INTERROGATORY #53 List 1

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1– Service Reliability Indicators/ Issue 1.6

a. In Table 2, Hydro One has listed figures referred to as OEB Targets for 2004 – 2008. Please confirm that Hydro One's definition of the targets for reliability indicators is based on the following statement documented in sections 15.2.1, 15.2.2 and 15.2.3 of the 2006 Electricity Distribution Rate Handbook: "A distributor that has at least 3 years of data on this index should, at a minimum, remain within the range of their historical performance." Has Hydro One received any directives from the Board regarding these targets? If not, please explain the basis for the OEB targets shown in Table 2 including references to the Board's directives. Please provide the mathematical derivation (e.g. mean) of the OEB Targets as shown in Table 2.
b. Hydro One has established 2007 to 2008 targets for the SAIFI, SAIDI, and CAIDI that are identical to the 2006 targets. Please describe why Hydro One has not established any improvement targets given the fact its reliability performance is lower compared to its peer utilities, when measured by metrics such as SAIDI and SAIFI, as noted in the Hydro One Distribution Benchmarking Study at page 1-5 and page 4-20 in section 4.2.3.
c. Worst Performing Circuits" ("WPC") is a common methodology used in the electricity distribution industry to identify those sections of a distributor's network most in need of maintenance or replacement due to reliability concerns. WPC consists of a list of those circuits or segments of the network that have the greatest incidence of outages. Over time, consecutive WPC lists can also indicate a utility's efforts to address the most unreliable parts of its network. For example, appearance on the WPC list of an individual circuit for at least three consecutive years could raise concerns about the utility's efforts to prioritize and address service degradation for those customers served by that circuit.
    i) Does Hydro One use Worst Performing Circuits methodology, as an internal tool for measuring and managing system reliability?
    ii) If it does not, then please explain why Hydro One does not use this approach. What other methods does Hydro One employ that would be comparable to WPC, and why does Hydro One prefer these other approaches?
    iii) If Hydro One does use WPC as a methodology, then please state how Hydro One uses this information to enhance the reliability of its system. Please also describe Hydro One's process for collecting information on WPCs, including a clear definition / description of the WPC methodology employed by Hydro One (i.e., the definition of a circuit, types of outages, if parts of the network excluded).and how the data are analyzed by Hydro One to identify worst performing circuits that require attention. Please provide, if available, Hydro

One's WPC lists for the years 2004 to 2007 inclusive. Please explain how HydroOne uses the WPC in developing its Opex and Capex plans for the next year for the intention of improving system reliability in at least parts of its network. Please identify specific capital projects, if any, for the 2008 test year which have been developed or accelerated based on the WPC information Hydro One has collected for 2006 and 2007.

Response

a. Hydro One confirms that its definition of the targets for reliability indicators is based on the statements documented in sections 15.2.1, 15.2.2 and 15.2.3 of the 2006 Electricity Distribution Rate Handbook.

The Rate Handbook section referred to in the question states that "A distributor that has at least 3 years of data on this index should, at a minimum, remain within the range of their historical performance". SAIDI and SAIFI targets are therefore not "means" but rather the outside limit of acceptable duration or frequency based on three years' previous experience. See the chart below for an example of how the OEB SAIDI targets have been set.

SAIDI Target process 2003 to 2007

Year	SAIDI Values (Yellow = actual; green = targets = maximum of previous 3 years)				
2000	7.5				
2001	8.7	8.7			
2002	9.4	9.4	9.4		
2003	9.4	8.0	8.0	8.0	
2004		9.4	6.5	6.5	6.5
2005			9.4	8.0	8.0
2006				8.0	7.1
2007					8.0

Hydro One has not received any directives from the Board regarding these targets other than the statements in the Rate Handbook.

b. The 2007 and 2008 targets shown in Table 2 of Exhibit A, Tab 15, Schedule 1 are based on the Rate Handbook requirements as discussed in part a). The values referenced in Table 2 are not targets established by Hydro One Distribution.

c.

i. Hydro One does use Worst Performing Circuit methodologies, but not in the conventional sense where one methodology based on a single or limited number of metrics is given precedence over others. There are a number off reasons why Hydro One has adopted a broader approach in terms of worst performing feeders, some of which are: variations in feeder lengths in Hydro One's system which make it difficult to obtain meaningful results from one primary measure; feeders in Hydro One's territory operate under varied environmental conditions, i.e., heavy to very few trees. These factors require Hydro One to look more closely at each feeder in order to take appropriate action to address reliably issues.

ii. As Hydro One does not use one primary factor to identify worst performing circuits, we have chosen to respond to this question rather than iii) below.

Hydro One has chosen to use a number of means to identify where rehabilitation and maintenance work is required. Hydro One recognizes that reliability can be measured using a variety of metrics (e.g. SAIDI, SAIFI, number of sustained interruptions, interruption trends) and that a circuit performing poorly based on one metric may be performing well based on another. As a result, emphasis on one or a select few performance metrics may encourage allocation of limited funds to work that should not be high priority when all factors are considered. This is why Hydro One has not adopted a broader approach.

Hydro One's reliability management approach offers an alternative to a single Worst Performing Circuit methodology. Its approach embeds a reliability focus in each category of work and targets poor performing circuits by relating particular performance metrics and criteria to particular types of programs/projects. For example,

a. Vegetation Management – The overall funding level is set considering Hydro One's system wide tree-caused SAIDI and tree-caused SAIFI. Circuits are then prioritized and scheduled for line clearing considering tree-caused interruptions.

b. Line Projects – All line project justifications consider reliability performance but a particular subset of projects is identified and scheduled based on root cause analysis that is triggered by poor SAIFI performance.

c. Reliability Enhancement Projects – Circuits are targeted for these projects based on Customer Interruptions and Customer Hours of Interruption.

d. Preventative & Corrective Maintenance – The overall funding envelope is set considering Hydro One's system wide equipment-caused SAIDI and equipment-caused SAIFI. Activities associated with specific programs such as Insulator Washing, Defect and EPAC insulator replacements, and other maintenance projects are scheduled considering the number of related sustained interruptions.

iii Does not apply.

Ontario Energy Board (Board Staff) INTERROGATORY #54 List 1

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1, Page 2 – Reliability Performance/ Issue 1.6

a. Please provide details on Hydro One's Outage Response Management System and explain if it is used as an outage management system dealing with both planned and unplanned outages. Please also explain if, and if so, how it is integrated with Hydro One's SCADA system.
b. Please state to what degree Hydro One uses distribution automation in dealing with planned and unplanned outages to reduce interruption duration and enhance restoration time.

Response

a. The Outage Response Management System (ORMS) uses a detailed database of Hydro One's Distribution System which contains the relationship between each Hydro One Customer account and the upstream devices (fuses, reclosures, etc.) which operate to isolate a fault. ORMS is also connected to an Interactive Voice Response (IVR) system and to an application that is used by the Call Centre Agents to report customer trouble calls. When customers phone in to report a power outage, they can enter their account number via the IVR or by speaking to Call Centre Agent. ORMS uses that account information in combination with its database to determine the likely device that has operated to isolate the fault. As more customers call in, the determination of the open device becomes more precise. Once the open device is determined, crews can be directed to it. This saves the time crews used to spend trying to find the outage location by driving along the feeders. ORMS updates the IVR with the list of all customer accounts that are affected by the outage. Any of those customers who subsequently call received an automated message that the outage is known together with information on when the power will be restored. All customers that called in receive a callback, via an Auto Dialer, to confirm their power has been restored. This helps to ensure another problem, not detected by ORMS does not get missed before the crews leaves the area.

The foregoing is a summary of the key functionality of ORMS for unplanned outages. Typically, 90% of outages are unplanned. ORMS is also used to help provide notifications and obtain customer feedback for Planned Outages. For this, the Auto Dialer is used to place calls to each customer that will be affected. Customers are given the option of having a Grid Operations Clerk contact them if the outage is problematic.

At this time HONI has no telemetry on the Distribution System.

b. HONI has a limited program to install automatic reclosures on some feeders in key locations, determined by outage history and number of customer impacted. The objective is to improve SAIDI performance. HONI also is initiating a limited program to install monitoring at DS's which are heavily loaded and need closer monitoring. The information received from this monitoring will be used by Operating staff for detection of power quality issues at the distribution stations as well as improvement in identifying faulted locations and devices. A project has been identified to use outage information from Smart Meters in ORMS. This is several years away, once the Smart Meter project is nearing completion.

Ontario Energy Board (Board Staff) INTERROGATORY #55 List 1

Interrogatory

Ref: Exhibit D1 Tab 2 Schedule 1 – Rights-of-Way Vegetation Management/Issue 4.3
On page 7, in Table 4.1 on its Asset Condition Assessment results, Hydro One reports that 31% of its lines, under the category of ROW Vegetation Management, is in "Poor" or "Very Poor" condition and requires Priority 1 (P1) attention.

On page 16, Hydro One states, "For Hydro One Distribution, the condition of rights of way is of great concern, as vegetation caused interruptions are the single greatest contribution to unreliability, as illustrated in Exhibit A, Tab 3, Schedule 1, and Exhibit C1, Tab 2, Schedule 2. The projected accomplishment of 12,900 km during 2007 and 12,500 during 2008 will not fully address the 'poor' and 'very poor' locations over these two years. These conditions will diminish over the next few years, but will not be fully addressed until one maintenance cycle has been achieved."

a. Please state the cycle for the rights-of-way ("ROW") vegetation management program.
b. Please explain how a different cycle or/and expenditure level for ROW vegetation management program would address the concerns about distribution network reliability raised by Hydro One.
c. If Hydro One had adopted the practice of optimum ROW vegetation management cycle discussed in b) above in 2004 or 2005, resulting in increased accomplishment of ROW kilometres clearance to date, please state the estimated impact of this practice on Hydro One's reliability performance (as measured by SAIDI and SAIFI) for 2006 to 2007 given Hydro One's knowledge on vegetation-caused interruptions and their contribution to unreliability in recent years.

Response

a. As stated in Exhibit C1, Tab 2, Schedule 2, accomplishments over the 2004-2006 period averaged 9,300 km for line clearing and about 10,000 km for brush control. Over the 2004-2007 period, the average accomplishments are 10,000 km for line clearing and 10,200 km for brush control, which is equivalent to a 10-year cycle.

b. A shorter cycle will address reliability concerns by improving SAIDI and SAIFI as discussed in the responses to interrogatories in Exhibit H, Tab 1, Schedule 49 and Exhibit H, Tab 1, Schedule 51.

c. As discussed in the interrogatory responses referenced in part b, the full reliability benefit of adopting an 8-year cycle is only realized after a full 8-year period has

elapsed. All things considered equal it is estimated that benefits would have been in the order of 2% for SAIDI and less for SAFI.

Ontario Energy Board (Board Staff) INTERROGATORY #56 List 1

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, Page 2 – Summary of Distribution Capital Expenditures/ Issue 4.2

a. Please re-construct Table 1, showing sustaining, development, operations, and shared services & other capital for 2004 – 2008 capital expenditures for the following dis-aggregation of capital expenditures:
   i) smart meters only;
   ii) customer growth-related only;
   iii) Information Technology initiatives only;
   iv) Information Technology initiative – Cornerstone only; and
   v) Excluding smart meters, customer growth-related and Information Technology initiatives.
b. For categories III) and V) in "a" above, please provide variance analysis showing year-over-year changes in expenditures, and provide explanations for material (i.e., greater than 5%) decreases or increases in capital expenditures in each of these categories.
c. For "V", please provide an explanation on the impact on reliability performance due to the increase or decrease in expenditures. Please provide a description, cost, and implementation timelines of all programs that **directly** contribute to enhancement of reliability performance.
d. Please provide the cost/ benefit analysis Hydro One has prepared to identify the benefits to consumers for spending related to smart meter excess functionality.
e. Please provide a numerical table that summarizes all of the capital costs in this application associated with smart meters for 2006, 2007 and 2008. For example, capital expenditures for smart meters, all related equipment, installation labour, computer systems software and hardware considered to be AMI, workforce management programs, Capgemini contract costs, computer systems in the IT section of the application that relate to smart meters, MDM/R-related computer system development costs, etc.

Response

a. Table 1 has been reconstructed with the dis-aggregation requested. The 2004 to 2007 amounts are actuals and the 2008 amounts are as requested per our Application:

$M

	2004	2005	2006	2007	2008
Distribution Capital					
Sustaining					
I) Smart meters only			14.1	76.7	164.8
V) Other *	104.9	117.3	172.2	146.9	152.3
Total Sustaining	104.9	117.3	186.3	223.6	317.1
Development					
II) Customer growth-related only	138.6	141.7	146.8	154.2	167.7
Operating					
V) Other *	6.3	4.7	2.1	2.0	3.6
Shared Services and Other Costs					
III) Information technology initiatives only	10.6	19.5	19.3	20.1	15.3
IV) Information technology initiatives only - Cornerstone only			0.0	26.6	28.0
V) Other *	11.5	34.0	38.1	50.1	34.5
Total Shared Services and Other Costs	**22.1**	**53.4**	**57.4**	**96.7**	**77.8**
Total Distribution Capital	**272.0**	**317.2**	**392.6**	**476.6**	**566.2**

* Where "Other" = "Excluding smart meters, customer growth-related and information technology inititaives"

b. Variance analysis showing year-over-year changes in expenditures for categories III) and V) in “a" above, and explanations for material (i.e., greater than 5%) decreases or increases are provided in the table below.

	Capital Expenditures $M		Capital Expenditures $M	Change	%	Year-over-year change
Category III) Information technology initiatives only						
2005	19.5	**2004**	10.6	8.9	83%	Higher spend on both common major projects ($7M) and computer acquisitions ($2M). This would include projects to facilitate integrated work planning, and replace an outdated computer telephony interface, call centre
2006	19.3	**2005**	19.5	(0.2)	-1%	
2007	20.1	**2006**	19.3	0.8	4%	
2008	15.3	**2007**	20.1	(4.7)	-24%	Lower expenditures on Distribution customer care IT projects ($2M), lower common major IT project expenditures ($1M) and lower computer acquisitions ($2M)
Category V) Other		Please note that this represents the sum of 3 line items from part a, each labelled as "other"				
2005	156.0	**2004**	122.7	33.3	27%	The 2005 capital expenditures required to sustain our distribution system increased primarily due to increased investments related to storm damage recovery and transport and work equipment, including brush clearing equipment to assist with our forestry program. These increases were partially offset by a reduction in our capital expenditures to expand and reinforce the low voltage distribution system. This reduction was attributable to a labour disruption, the impact of which was partially offset by increased new connections work. Lines expenditures were also higher in new customer connections and joint use and relocations. Transport & Work Equipment expenditures moved forward from 2004 into 2003 increased the appearance of differences in expenditures
2006	212.4	**2005**	156.0	56.3	36%	The 2006 increases were primarily due to higher planned replacements of end of life assets (e.g. wood pole replacement), combined with increased expenditures for other unplanned asset replacements and line relocations, higher-than-expected new customer connections, as well as the impact of last year's labour disruption. Expenditures also reflect higher asset replacement expenditures related to storm damage. This year also marked the initiation of the Smart Meter project.
2007	199.0	**2006**	212.4	(13.3)	-6%	Distribution Capital is lower than in 2006 due primarily to lower Engineering & Construction spending on our Wholesale Metering work and lower storm recovery work than last year, partially offset by an expanded end-of-life planned pole replacement program and higher Lines development program work.
2008	190.4	**2007**	199.0	(8.6)	-4%	

c. Please refer to interrogatory response in Exhibit H, Tab 1, Schedule 52, part c.

d. Please see the interrogatory response in Exhibit H, Tab 1, Schedule 127 part i) for a discussion of the costs and benefits associated with the component that support Hydro One Networks business operations (i.e. the super capacitors in the meters and batteries in the regional collectors).

e. The capital cost summary for Smart Meters in Exhibit D2, Tab2, Schedule 1 page 1 represents all the capital costs associated with smart meters including the components listed in this interrogatory.

Ontario Energy Board (Board Staff) INTERROGATORY #57 List 1

Interrogatory

Ref: Exhibit A Tab 3 Schedule 1 and Exhibit D1 Tab 2 Schedule 1 – Service Reliability Indicators/ Issue 4.2 and Issue 4.8

On Pages 18 and 19 of Exhibit A/Tab 3/Schedule 1, Hydro One provides two pie charts illustrating the causes of outages and their proportionate contributions to SAIDI and SAIFI for the four year averages (2003-2006). Please reconstruct these figures to illustrate the proportion of Hydro One's three levels of priorities for its asset classes that are shown in Figure 1 of Exhibit D1 Tab 2 Schedule 1, page 3, as applicable, (i.e. showing the % contribution for station transformers, % of contribution for wood poles, etc. on SAIDI and SAIFI).

Response

Hydro One is unable to provide the pie charts by cause categories broken out for all equipment asset classes. Hydro One can confirm that the "Tree Contacts" and "Force Majeure – Tree Contacts" are directly related to the "Priority 1 – Right of Way Vegetation Asset Class", but this correlation cannot be made with other asset classes, as there is insufficient data to do so.

Ontario Energy Board (Board Staff) INTERROGATORY #58 List 1

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1 - Asset Condition/ Issue 1.6 and Issue 4.3
On Page 3, Figure 1 of Exhibit D1, Tab 2, Schedule 1, Hydro One illustrates three levels of prioritization for its asset classes. Please provide an explanation of how, and to what degree, Hydro One's prioritization of replacement and maintenance programs for these assets are influenced by Hydro One's reliability performance as measured by SAIDI, SAIFI and other measures of reliability that Hydro One might be using for operational purposes.

Response

Exhibit A, Tab 14, Schedule 5 details Hydro One's Work Program Prioritization process. All work programs, regardless of their focus in terms of the asset classes, are taken through the prioritization process which includes, among other considerations, the evaluation of reliability risks in terms of the impact on SAIDI and SAIFI performance. Higher priority assets are more critical to the reliable operation of the distribution system and as a result, programs that replace and maintain them will require more to be done to achieve lower levels of risks.

Ontario Energy Board (Board Staff) INTERROGATORY #59 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 1 Page 2/Issue 3.1

a. Please provide in table format, total OM&A per customer for each year from 2002 to 2008. Please calculate the year-to-year variances and identify the drivers for the increase/decrease.
b. Please also provide a table format, total OM&A per circuit km of distribution lines for each year from 2002 to 2008. Please calculate the year-to-year variances and identify the drivers for the increase/decrease.

Response

a. and b.

	Total OM&A per customer ($)	year to year variance ($)	Total OM&A per circuit km ($)	year to year variance ($)	Drivers
2002	304		2,844		
2003	303	-1	2,849	5	variance is less than 1%
2004	305	2	2,900	49	variance is less than 1%
2005	316	11	3,027	127	Increased forestry work program while reducing trimming cycles; increased expenditures to restore power due to storm activity; initiation of conservation and demand management programs. Partially offset by lower labour costs resulting from labour disruption, and the impact of Hydro One hurricane relief to Florida Power and Light Company the previous year.
2006	350	34	3,372	345	$14.1M increase in Trouble Calls associated with storm damage. Minor increases in other maintenance programs, including: Line Maintenance, Stations Planned Maintenance, Customer Retail Meters, and Brush Control.
2007	422	72	4,097	725	$25M increase in Vegetation Management. Increase of $5M in expenditures in support of the Conservation & Demand Management program. Decrease in overheads recovered due to a reduction from 17% to 12% in the overhead recovery rate. Impact of the OEB's decision regarding 2006 deferred pension cost and smart meters.
2008	406	-16	3,973	-124	variance is less than 1%

Ontario Energy Board (Board Staff) INTERROGATORY #60 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 2 Page 3/Issue 3.1

What has been the proportion of Sustaining 'planned work' versus 'unplanned work' from 2006 to 2007? What is the forecast of planned work vs. unplanned work for 2008? Please explain how these forecasts were developed. Please also quantify the drivers/assumptions underpinning the 2008 forecast.

Response

The breakdown of planned versus unplanned Sustaining OM&A work is provided below:

	2006	2007	Forecast 2008
OM&A Sustainment			
Planned	147.8	181.4	186.5
Unplanned	107.8	97.4	93.5
Total	**255.6**	**278.8**	**280.0**

The forecasts contained in the above table are an aggregate of sustaining expenditures for each OM&A work program and project described in Exhibit C1, Tab 2, Schedule 2. The 2008 forecast is developed from an analysis of historic trends while accounting for any known effects which may cause a deviation from historic levels. Planned expenditures are generally based on asset needs established through asset condition assessments and other considerations that include technical obsolescence, regulatory requirements, environmental factors, spare parts availability and asset performance.

Ontario Energy Board (Board Staff) INTERROGATORY #61 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 2 Page 7/Issue 3.1
With respect to "planned station maintenance", Hydro One states, "The 6,000 station reclosers are maintained on a 6 year interval, and airbreak switches, circuit switchers, high voltage fuses, and transformer underload tap changers are maintained on a similar interval. These activities in addition to mid-life maintenance overhaul on major equipment, management of station PCBs, transformer diagnostics and technical services account for a 2008 spending of $8.6 million."

a. Are all 6000 stations maintained once every six years or are 1000 stations maintained every year within a 6 year cycle?
b. Please provide the actual spending amounts for the 2006 and 2007 year for the above activities. In addition, please calculate the year-to-year variances from and explain the changes.
c. Since station reclosers are maintained on a 6 year interval, would the amount allocated to the activity be considered a one-time cost in 2008?
d. If so, please state why Hydro One believes that this one-time cost should be included in the 2008 rates and continued into 2009 and 2010 under the IRM process.
e. If not, please provide a proposal on how the 2008 one-time costs should recovered in this application.

Response

a. Hydro One maintains approximately 1/6 of the stations (i.e. 1000) every year of the 6 year cycle.

b. Actual 2006 and 2007 spending for maintaining recloser, airbreak switch, circuit switchers, high voltage fuses and transformers, and PCB transformer diagnostics and technical services are:

2006 - $8.0 million
2007 - $ 9.3 million

The primary reason for the variance is that the maintenance plan for reclosers changed during 2006 to a centrally managed program from a de-centrally managed program. This resulted in some delays in implementing the revised recloser maintenance program.

c., d. and e. These are not one time costs. Station maintenance is an on going expense for Hydro One.

Ontario Energy Board (Board Staff) INTERROGATORY #62 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 2 Page 30/Issue 3.2

a. Regarding Line Clearing, please provide an explanation for the significant increase of $23.5 million (46%) from 2006 to 2007. Please also identify and quantify the drivers for this increase.
b. Please identify the amount of the 2008 spending requirement for line clearing that is related to one-time costs.
c. If any of the stated 2008 costs are one time costs, please explain why Hydro One believes that these should continue to be part of the 2009 and 2010 budget.

Response

a. Line clearing accomplishments are provided in the response in Exhibit H, Tab 1, Schedule 63. Line Clearing accomplishments in 2007 were 37% greater than those in 2006, which is the primary reason for the increase in spending. The remainder is attributed to escalation and an increased effort required to complete the work.

b. There are no one time costs contained in the 2008 spending requirement for line clearing.

c. Does not apply.

Ontario Energy Board (Board Staff) INTERROGATORY #63 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 2 Page 30/Issue 3.2
Please provide the actual and budgeted number of kilometres of line clearing and brush control for each of the years 2004 to 2007. Please explain the reasons for any variances between the actual kilometres of line clearing and brush control and budget for each of the years requested.

Response

The following tables provide actual and budgeted numbers of kilometers of line clearing and brush control accomplishments for the years 2004 to 2007.

Line Clearing	**2004**	**2005**	**2006**	**2007**
Plan (km)	10,500	10,300	10,700	12,900
Actual (km)	10,361	8,746	8,889	12,211
Variance (km & % of Budget)	-139 (-1%)	-1,255 (-18%)	-1,811 (-17%)	-689 (-5%)

Brush Control	**2004**	**2005**	**2006**	**2007**
Plan (km)	10,500	11,000	10,700	11,100
Actual (km)	10,731	9,076	10,246	10,777
Variance (km & % of Budget)	+231 (2%)	-1,924 (-17%)	-454 (-4%)	-323 (-3%)

The following are variance descriptions for each year:

2004 – Both programs were on budget as program variances are negligible (1% to 2%)

2005 – Under-accomplishment is primarily attributed to the Society of Energy Professionals strike that lasted almost four months (June to September) during the peak vegetation maintenance season. During the strike, field staff were detained at picket lines at a number of Hydro One sites, and as a result accomplishments were not as high as expected.

2006 – During 2006 Hydro One experienced 8 force majeure storms, which resulted in an unprecedented 36 days of storm restoration. To restore power after these storms, Hydro One redirected resources, including forestry crews from planned programs to storm restoration.

2007 – This was the first year Hydro One employed external contracting resources for line clearing. As a result of delays in finalizing the contracts, accomplishments fell

slightly short of the target amount for line clearing. Brush control accomplishments were close to plan.

Ontario Energy Board (Board Staff) INTERROGATORY #64 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 3 Page 2/Issue 3.1

a. In regards to Table 1, please provide an explanation as to why the Data Collection, Engineering and Technical Studies costs grew by over 85% in 2007? Please identify and quantify the drivers for any variances between 2006 and 2007 spending. Please also explain why these expenditures are forecasted to remain at this level for the 2008 test year.
b. Are any of the expenditures related to Development OM&A one-time costs?
c. If any of the stated 2008 costs are one time costs, please explain why Hydro One believes that these should continue to be part of the 2009 and 2010 budget.

Response

a) The $2.4 M increase in 2007 expenditures over 2006 is attributed to the following:
- Increased analysis of the distribution system and data collection to ensure protections function as intended and are synchronized, to ensure operating conditions remain within equipment ratings and address phase imbalance. These costs contributed $1.1 million to the increase.
- Training of new staff that was required to address the added work load and pending retirement of senior staff, as well as additional software licenses for the system analysis software. Additional staff were required to address the increasing work load in generation connections and engineering studies. These costs contributed $1.2 million to the increase.

Expenditures associated with new staff training and software will decline in 2008. However, the total expenditure level is expected to remain the same in 2008 due to new activities associated with resolving Long Term Load Transfers (LTLTs) with other LDCs, and data collection and studies associated with proactive feeder modeling for potential wind generation,.

b) Yes there are some expenditures related to Development OM&A which are one time costs associated with Long Term Load Transfers, but other LTLT costs will continue through 2009.

c) In terms of future costs, it is our experience that the demand for information is in an increasing trend and this program will be required to fund the studies and data acquisition to respond to some of these demands, some of which are known and

others which are currently unforeseen. More specifically, Hydro One is seeing a greater need to be able respond to aspects on system losses and the Smart Grid. In order to provide relevant and accurate information and to address possible misunderstandings by interested parties, added analysis and data acquisition will be required.

In addition, as a greater number of new generators are connected, operating complexities will increase thereby requiring the need to better understand the behaviour of these mini-grid systems. These operating complexities will drive added system studies. Although the scope of the increase in work is not fully defined at this time, it is anticipated there will be added demands for a greater number of studies.

Ontario Energy Board (Board Staff) INTERROGATORY #65 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 5 Page 3/Issue 3.1
Please provide the Total Customer Care cost per customer from 2002 to 2008.
Please explain the reasons for the year-to-year variances.

Response

The table below provides the cost/customer of the total Customer Care Work program.

Description	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Total Customer Care cost (M$)	94.8	96.5	103.0	96.3	103.7	97.1	103.8
Customers (K)	1,118	1,133	1,145	1,158	1,170	1,183	1,194
Customer Care cost per Customer ($)	84.79	85.17	89.96	83.16	88.63	82.08	86.94

The variance between years is due in part to bad debt costs which can fluctuate year-to-year. As well, an allowance provision of $3.6 million was applied in 2006 for a multi-year adjustment to bad debt costs.

The year-over-year changes also reflect incremental costs in some years to address volume changes in calls to the Customer Communications Centre, typically as a result of storms. For example, additional call volume costs were incurred in 2006 due to the high number of storms experienced that year.

Costs were down in 2005, in part as a result of lower labour costs due to the extended Society strike.

In 2008, our work program reflects an increase in Regulatory Projects to implement proposed distribution rate changes and increased investment in collection activity to manage bad debt costs.

Ontario Energy Board (Board Staff) INTERROGATORY #66 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 5 Page 11/Issue 3.1
The distribution related costs for customer care management are forecasted to be $7.2 million in 2008. This represents in an increase of $3.1 million from 2006. Hydro One cites that the increase is due to a number of factors including: supporting the corporate objective of improved customer satisfaction; refining management practices associated with the Inergi contract to assist in raising serve quality to customers; preparing for time of use billing related to the incorporation of smart meters.

Please provide a breakdown of the spending for the various factors listed above for the years 2006 through 2008. Please also explain the year-over-year variances and identify the drivers of these variances.

Response

There is no breakdown in costs for the factors listed above, as staff time was not tracked against these specific items. These factors did have an influence on the amount of time that Customer Care staff spent on Distribution programs, which led to a shift in the allocation of the Customer Care Management costs from 70% to Distribution in 2006 to 96% to Distribution in both 2007 and 2008. This increase in allocation to Distribution accounts for $1.6M of the $3.1M growth in Customer Care Management costs from 2006 to 2008.

The remainder of the increase is due to: labour escalation per the Company's labour agreements; modest increases in staff complement and structure to assist in managing the Customer Care work program; and minor increases in third party contracts.

Ontario Energy Board (Board Staff) INTERROGATORY #67 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 5 Page 13/Issue 3.1

With regards to Service Enhancements, please provide a breakdown of the spending in the various activities listed in lines 7 through 11 for the years 2006 through 2008. Please also explain the year-over-year variances and identify the drivers of these variances.

Response

There are no year-over-year variances for the years 2006 through 2008 because these are new Service Enhancement projects that are planned to be launched in 2008.

The table below provides a breakdown of the activities listed in lines 7 through 11.

Service Enhancement Projects	2008
Promotion of Summary Billing	0.1
Web Self Service Options	0.3
Process Efficiencies for Bill Exception Handling	0.1
Review & Update to Call Centre IVR menus/self serve options	0.3
Improvements to First call resolution	0.2
New Collections initiatives to enhance receivables recovery	0.6
TOTAL - Service Enhancements Projects	**1.6**

The table above includes examples of the Service Enhancement initiatives planned for 2008. Other initiatives underway include improving the call quality monitoring program, promoting electronic billing, improving processes when customers provide meter reads, and improving processes for interval meter data. These make up the $1.0 million balance of the Service Enhancement budget, as noted in Table 1, Exhibit C1, Tab 2, Schedule 5.

Ontario Energy Board (Board Staff) INTERROGATORY #68 List 1

Interrogatory

Ref: Exhibit C – Regulatory Costs/Issue 3.1
Please complete the table below with respect to regulatory costs:

	Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 (as of Dec 07)	% Change in 2007 vs. 2006	2008 Forecast	% Change in 2008 vs. 2007
1	OEB Annual Assessment							
2	OEB Hearing Assessments (applicant initiated)							
3	OEB Section 30 Costs (OEB initiated)							
4	Expert Witness cost for regulatory matters							
5	Legal costs for regulatory matters							
6	Consultants costs for regulatory matters							
7	Operating expenses associated with staff resources allocated to regulatory matters							
8	Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)							
9	Other regulatory agency fees or assessments							
10	Any other costs for regulatory matters (please define)							

Response

Please see the following table:

Regulatory Costs

	Regulatory Cost Category	Ongoing or One-time Cost?	2006 Board Approved	2006 Actual	2007 (as of Dec 07)	% Change in 2007 vs. 2006	2008 Forecast	% Change in 2008 vs. 2007
1	OEB Annual Assessment	Ongoing	9.1	8.8	10.1	15%	10.8	7%
2	OEB Hearing Assessments (applicant initiated)	Ongoing	0.1	0.0	0.1	-%	0.0	-100%
3	OEB Section 30 Costs (OEB initiated)	Ongoing	0.0	0.0	0.0	0%	0.0	0%
4	Expert Witness cost for regulatory matters	Ongoing	0.0	0.0	0.0	0%	0.0	0%
5	Legal costs for regulatory matters *	Ongoing	0.0	0.0	0.0	0%	0.0	0%
6	Consultants costs for regulatory matters	Ongoing	0.9	0.3	0.3	0%	0.2	-33%
7	Operating expenses associated with staff resources allocated to regulatory matters	Ongoing	6.1	6.3	6.8	8%	8.1	19%
8	Operating expenses associated with other resources allocated to regulatory matters (please identify the resources)	Ongoing	1.1	0.4	0.7	75%	0.6	-14%
9	Other regulatory agency fees or assessments	Ongoing	0.0	0.0	0.0	0%	0.0	0%
10	Any other costs for regulatory matters (please define)	Ongoing	0.0	0.0	0.0	0%	0.0	0%
	TOTAL [(a)]		17.3	15.8	18.0	14%	19.7	9%

(a) Reference Exhibit C1, Tab 2, Schedule 6, page 28, Table 10

* In addition, legal costs in support of regulatory proceedings are managed by General Counsel (~200K per annum)

Ontario Energy Board (Board Staff) INTERROGATORY #69 List 1

Interrogatory

Ref: Exhibit C1 Tab 3 Schedule 1 and 2/Issue 3.6

On Page 1, Hydro One indicates that its primary human resource challenges are an aging workforce, world-wide scarcity of core skills in the industry, and a highly competitive labour market.

a. Please describe Hydro One's plan to address its human resource challenges.

Response

Hydro One is at the forefront in recognizing and implementing strategies for dealing with the demographic challenges facing the electricity industry. Since 2000, Hydro One has ramped up its recruitment efforts, with a strong emphasis on our Apprenticeship and Graduate Trainee Programs as well as taking on a leadership role with universities and colleges in assisting with curriculum development, providing scholarships, offering hundreds of co-op work terms, providing Fellowship placements and funding for things such as lab equipment. Hydro One also plays a key role in increasing the number of skilled individuals in the industry by holding the Chair of the Electricity Sector Council as well as the Human Resources Chair of the Canadian Electrical Association. Details of the various initiatives can be found in Exhibit C1, Tab 3, Schedule 1, pages 5-8.

Ontario Energy Board (Board Staff) INTERROGATORY #70 List 1

Interrogatory

Ref: Exhibit C1 Tab 3 Schedule 2/Issue 3.6
The table at Exhibit C1/Tab 3/Schedule 2/Page 1 provides a breakdown of total salary and wages for 2004 to 2008. Please expand this table to include 2006 Board approved and actual amounts.

Response

Below is the updated chart with 2006 Board approved amounts included.

Year	Total Wages	Base	Overtime	Incentive	Other**
2004	404.2	323.7	53.2	12.3	15.0
2005	397.9	321.1	50.6	8.4	17.7
2006 Approved+	430.0	354.6	57.0	3.4	15.0
2006	459.3	368.0	66.5	4.4	20.5
2007	495.5	414.7	60.9	6.6	13.2
2008	580.7	475.5	72.1	8.5	24.6

* This payroll reflects compensation costs associated with year-end headcounts for all EPSCA, PWU, Society and MCP staff.
** "Other" includes travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination.
+ As submitted by Hydro One in EB-2005-0378

Ontario Energy Board (Board Staff) INTERROGATORY #71 List 1

Interrogatory

Ref: Exhibit C1 Tab 3 Schedule 2/Issue 3.6
Please provide a breakdown of total employee costs charged to OM&A and to Capital for the years 2006 (Board approved and actual), 2007 and 2008.

Response

The estimated breakdown is provided in the following table:

Total Wages
Hydro One Networks Inc.

M$	**2006 Board Approved**	**2006**	**2007**	**2008 Test Year**
OM&A	263.4	281.4	298.3	349.6
Capital	166.6	177.9	197.2	231.1
Total	**430.0**	**459.3**	**495.5**	**580.7**

Ontario Energy Board (Board Staff) INTERROGATORY #72 List 1

Interrogatory

Ref: Exhibit C1 Tab 3 Schedule 2/Issue 3.6
On Page 1, Hydro One provides a breakdown of total salary and wages for 2004 to 2008. This table indicates that total incentive has increased from $4.4M in 2006 to $8.5M in 2008. Please provide the rationale (including drivers of this increase) and justification for the 93% increase.

Response

Hydro One incentive payments for management staff are paid in January and are based on performance in the preceding year. The chart reflects the incentive payments in the year that the payments are received. For the 2006 calendar year a significant number of new management staff were hired. Given these staff were new to management they did not receive any incentive payments in 2006. This resulted in the 2006 incentive payment being disproportionably low on a per capita basis. In 2008, the staff hired into management in 2006 are eligible for incentive payment. This results in the increase in the incentive payment in 2008.

Ontario Energy Board (Board Staff) INTERROGATORY #73 List 1

Interrogatory

Ref: Exhibit C1 Tab 3 Schedule 2/Issue 3.6

On Page 1, Hydro One provides a breakdown of total salary and wages for 2004 to 2008. This table indicates that total base salary has increased from $367.7M in 2006 to $406.4M in 2008. Please provide the rationale (including drivers of this increase) and justification for the 11% increase.

Response

This number is a reflection of an increase in staff numbers due to increased work programs as well as base increases negotiated by the various trade unions for represented staff and a base pay increase for management staff.

Ontario Energy Board (Board Staff) INTERROGATORY #74 List 1

Interrogatory

Ref: Exhibit A-15-2 Attachment B/Issue 3.6
Please comment on how Hydro One has used or intends to use the 2007 Comparison of Labour Rates and Overtime Policy study and what results it expects to achieve. Please also file any implementation plans that Hydro One may have in this regard.

Response

Hydro One was directed to engage an independent party to " develop a comparison of labour rates and overtime policies amongst Hydro One, other comparative Ontario electricity distributors and other Canadian Utilities as identified in the high level benchmarking survey'. Hydro One submits that this study illustrates that the Hydro One sample jobs are generally within market rates and overtime policies for comparable positions in other organizations. As such, there are no specific plans other than to continue to monitor external comparators.

Ontario Energy Board (Board Staff) INTERROGATORY #75 List 1

Interrogatory

Ref: Exhibit C1-3-2 Appendix "A"/Issue 3.6
On Page 2, Hydro One provides a breakdown of total pension costs charged to OM&A and Capital. Please provide a revised table to include the years 2006 (Board approved and actual) and 2007.

Response

Revised table as below:

Annual cash pension cost (millions)

(*may not add due to rounding*)

2008 forecast				
Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$27	$33	$3	$63
Capital	$18	$23	$ -	$41
	$45	$56	$3	$104
Inergi Annual Pension Charge				
OM&A	$2	$4	$-	$6

2007 actual				
Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$22	$33	$3	$58
Capital	$14	$23	$ -	$37
	$36	$56	$3	$95
Inergi Annual Pension Charge				
OM&A	$2	$4	$ -	$6

Annual cash pension cost (millions)

(*may not add due to rounding*)

2006 actual				
Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$20	$29	$3	$52
Capital	$13	$21	$ -	$34
	$33	$50	$3	$86
Inergi Annual Pension Charge				
OM&A	$2	$4	$ -	$6

2006 Board Approved				
Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$19	$28	$3	$50
Capital	$12	$19	$ -	$31
	$31	$47	$3	$81
Inergi Annual Pension Charge				
OM&A	$2	$5	$ -	$7

Ontario Energy Board (Board Staff) INTERROGATORY #76 List 1

Interrogatory

Ref: Exhibit C1-3-2 Appendix "A"/Issue 3.6
On Page 2, Hydro One states that its next actuarial valuation will be prepared as at December 31, 2006 and will be filed with the Financial Services Commission of Ontario (FSCO) in September 2007. Please file the actuarial valuation that was submitted to FSCO on September 2007 along with a copy of the FSCO report.

Response

The actuarial valuation report is attached. There was no report received from FSCO.

September 5, 2007

HYDRO ONE INC.
PENSION PLAN AND FUND

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2006

MERCER
Human Resource Consulting

Ontario Registration Number: 1059104
Canada Revenue Agency Registration Number: 1059104

MMC Marsh & McLennan Companies

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Summary of Results

	(in 000s)	(in 000s)
Going-Concern Financial Position	**31.12.06**	**31.12.03**
Smoothed value of assets	$4,586,364	$4,141,237
Actuarial liability	$4,802,087	$4,308,535
Funding excess (shortfall)	($215,723)	($167,298)
Solvency Financial Position	**31.12.06**	**31.12.03**
Adjusted solvency assets	$5,223,765	$4,003,495
Solvency liability[(1)]	$4,251,243	$3,460,193
Solvency excess (deficiency)	$972,522	$543,302
Transfer ratio	88%	88%
Ratio of solvency assets to solvency liabilities	100%	100%
Wind-up Financial Position	**31.12.06**	**31.12.03**
Market value of assets	$5,116,874	$3,930,935
Wind-up liability	$5,819,796	$4,488,408
Wind-up excess (deficiency)	($702,922)	($557,473)

	(in 000s) 2007	(in 000s) 2004
Total current service cost	$87,040	$74,565
Estimated members' required contributions	$16,555	$14,477
Estimated employer's current service cost	$70,485	$60,088
Employer's current service cost as a percentage of members' pensionable earnings	20.3%	20.4%
Minimum special payments	$23,917	$16,769
Estimated minimum employer contribution for year[2]	$94,402	$76,857

[1] Hydro One elected to exclude indexing from the plan's solvency liabilities in the valuations as at December 31, 2003 and December 31, 2006

[2] Excluding any special contributions in respect of the indexing element of commuted values paid from the plan prior to July 1, 2006

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Introduction

Report on the Actuarial Valuation as at December 31, 2006

To Hydro One Inc.

At the request of Hydro One Inc. (the "Company"), we have conducted an actuarial valuation of the Hydro One Inc. Pension Plan and Fund as at December 31, 2006. We are pleased to present the results of the valuation.

The purpose of this valuation is to determine:

- the funded status of the plan as at December 31, 2006 on going-concern and solvency bases, and
- the minimum funding requirements from 2007.

The next actuarial valuation of the plan will be required as at a date not later than December 31, 2009 or as at the date of an earlier amendment to the plan, in accordance with the requirements of the *Ontario Pension Benefits Act*.

There is a funding shortfall of $215,723,000 as at December 31, 2006. As such, the minimum monthly contribution to be remitted to the plan from 2007 to 2009, is as follows:

Monthly Employer Contributions
For current service: 20.3% of members' pensionable earnings
Minimum special payments for unfunded liability: $1,993,054

On the basis of the members' estimated pensionable earnings, we have estimated the minimum total employer contribution for 2007 to be $94,402,000, or $7,866,833 per month.

The minimum contribution requirements based on this report exceed the minimum contribution requirements recommended in the previous valuation report. Upon filing this report, Hydro One Inc. must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following December 31, 2006. This contribution, along with an allowance for interest at the 6.0% valuation interest rate, is due no later than 60 days following the date this report is filed.

The plan is not fully funded on a wind-up basis. Even if the sponsor contributes in accordance with the funding requirements described in this valuation report, the assets of the plan may be less than the liabilities of the plan upon wind-up as the plan administrator has elected to exclude indexing in determining the minimum solvency deficiency payments. Emerging experience, including the growth of wind-up liabilities compared to the plan's assets (including future contributions and investment returns), will also affect the wind-up funded position of the plan.

This valuation reflects the provisions of the plan as at December 31, 2006. The plan has been amended since the date of the previous valuation to provide Society of Engineering Professionals hired on or after November 17, 2005 with modified pension benefits. A summary of the plan provisions is provided in Appendix D.

We have used the same going-concern valuation assumptions and methods as were used for the valuation as at December 31, 2003, except for the following:

- assumed inflation rate was increased from 2.25% to 2.50%
- salary scale was increased from 3.00% plus merit to 3.25% plus merit,
- YMPE scale was increased from 3.25% to 3.5%,
- mortality table was updated from the Group Annuity Mortality tables for 1994 to the UP 1994 generational mortality tables, and
- termination and retirement assumptions were updated based on the results of an updated experience study

These changes have resulted in an increase of $201,848,000 in the actuarial liability and of $3,496,000 in the employer current service cost. The assumptions used for purposes of this valuation are described in detail in Appendix B.

The solvency and wind-up assumptions have been updated to reflect market conditions at the valuation date.

The assumptions used for purposes of this valuation are described in Appendix B. All assumptions made for the purpose of the valuation were reasonable at the time the valuation was prepared.

A new Canadian Institute of Actuaries Standard of Practice for Determining Pension Commuted Values ("CIA Standard") became effective on February 1, 2005. The new CIA Standard changes the assumptions to be used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of the new CIA Standard has been reflected in this actuarial valuation.

On July 29, 2004, the Supreme Court of Canada dismissed the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("*Monsanto*"), thereby upholding the requirement to distribute surplus on partial plan wind-ups under *The Pension Benefits Act (Ontario)*. The decision has retroactive application. We are unaware of any partial plan wind-up having been declared in respect of the plan where *Monsanto* may apply. In preparing this actuarial valuation, we have assumed that all plan assets are available to cover the plan liabilities presented in this report. The subsequent declaration of a partial wind-up of the plan where *Monsanto* may apply in respect of a past event, or disclosure of an existing past partial wind-up, could cause an additional claim on plan assets, the consequences of which would be addressed in a subsequent report. We note the discretionary nature of the power of the regulatory authorities to declare partial wind-ups and the lack of clarity with respect to the retroactive scope of that power. We are making no representation as to whether the regulatory authorities might declare a partial wind-up in respect of other events in the plan's history.

The Financial Services Commission of Ontario received a request from a group of former active members that it declare a partial wind up under the Plan in respect of some terminations from 2000 through 2003. The Superintendent initially decided that a partial wind up would not be declared. Following an appeal by the plan members, the Financial Services Tribunal reached a decision on August 1, 2007 to declare a partial windup only in respect of 73 members whose terminations were effective between the period September 1, 2002 and December 31, 2002, inclusive. The Company decided to appeal the decision of the Financial Services Tribunal and served its appeal on August 24, 2007. Our valuation does not account for the impact of any ruling on this request. The declaration of a partial wind up, if any, is not expected to have a material impact on the funding status, on going-concern and solvency bases, or on the minimum funding requirements.

This report has been prepared on the assumption that the pending transfer of assets from the Hydro One Pension Plan to the Inergi LP Pension Plan is approved by the Financial Services Commission of Ontario (FSCO) in accordance with the asset transfer report dated November, 2002. The assets and liabilities associated with this transfer have been removed from the assets and liabilities of the Plan for the purposes of this report. This assumption is not expected to be material to the contribution requirements disclosed in this report.

To the best of our knowledge, there have been no other events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice. It has also been prepared in accordance with the funding and solvency standards set by the *Ontario Pension Benefits Act*.

The information contained in this report was prepared for Hydro One Inc. for its internal use and for filing with the Financial Services Commission of Ontario and with the Canada Revenue Agency, in connection with our actuarial valuation of the plan. This report is not intended or necessarily suitable for other purposes.

This report will be filed with the Financial Services Commission of Ontario and with the Canada Revenue Agency.

Respectfully submitted,

Scott Clausen
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept 5, 2007
Date

Malcolm P. Hamilton
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept. 5, 2007
Date

Hydro One Inc. Pension Plan and Fund
Registration number with the Financial Services Commission of Ontario and with the Canada Revenue Agency: 1059104

3

Financial Position of the Plan

Valuation Results — Going-Concern Basis

When conducting a valuation on a going-concern basis, we determine the relationship between the respective values of assets and accumulated benefits, assuming the plan will be maintained indefinitely.

Financial Position

The results of the valuation as at December 31, 2006, in comparison with those of the previous valuation as at December 31, 2003, are summarised as follows:

Financial Position — Going-Concern Basis (in 000s)

	31.12.06	31.12.03
Market value of assets	$5,131,430	$3,940,619
Net transfer in respect of reciprocal transfers	($1,727)	$168
Smoothing adjustment	($543,339)	$200,450
Smoothed value of assets	$4,586,364	$4,141,237
Present value of accrued benefits for:		
▪ active members and LTDs	$1,742,040	$1,411,126
▪ pensioners and survivors	$3,008,092	$2,860,695
▪ deferred pensioners	$51,939	$36,686
▪ additional voluntary contributions	$16	$28
Total liability	$4,802,087	$4,308,535
Funding excess (shortfall) (A)	($215,723)	($167,298)
Present value of existing going-concern unfunded liability special payments (B)	$144,414	$0
Going-concern unfunded liability created at this valuation (maximum of $0 and A-B)	($71,309)	($167,298)

Reconciliation of Financial Position

The plan's financial position, an unfunded liability of $215,723,000 as at December 31, 2006, is reconciled with its previous position, an unfunded liability of $167,298,000 as at December 31, 2003, as follows:

Reconciliation of Financial Position (in 000s)

Funding excess (unfunded liability) as at 31.12.03	($167,298)
Interest on funding excess (unfunded liability) at 6.00% per year to 31.12.06	(31,957)
Employer special payments with interest	71,351
Net experience gains (losses) over 2004-2006 *	114,029
Impact of assumption changes	(201,848)
Funding excess (unfunded liability) as at 31.12.06	(215,723)

* *Net experience gains (losses) are detailed below.*

Plan Experience

The main assumptions are compared with actual experience since the previous valuation as at December 31, 2003:

Plan Experience (in 000s)

	Impact Gain (Loss)
Investment return	127,109
Increases in pensionable earnings/YMPE	16,745
Increases in the maximum pension limit	(4,923)
Inflation experience	1,363
Retirements	(5,786)
Terminations	(21,578)
Mortality	(3,808)
Disability	5,626
Data corrections	(437)
Miscellaneous other experience	(282)
Net experience gains (losses)	114,029

Valuation Results — Solvency Basis

When conducting a solvency valuation, we determine the relationship between the respective values of the plan's assets and its liabilities on a solvency basis, determined in accordance with the *Ontario Pension Benefits Act*. The values of the plan's assets and liabilities on a solvency basis are related to the corresponding values calculated as though the plan were wound up and settled on the valuation date. The circumstances in which the plan wind up is assumed to have taken place are as follows: *unilateral termination of the plan*.

The value of future indexing has been excluded from the solvency liabilities, as permitted under the *Ontario Pension Benefits Act*.

Financial Position on a Solvency Basis

The plan's solvency position as at December 31, 2006, in comparison with that of the previous valuation as at December 31, 2003, is determined as follows:

Solvency Position (in 000s)

	31.12.06	31.12.03
Market value of assets	$5,131,430	$3,940,619
Net transfer in respect of reciprocal transfers	($1,727)	$168
Termination expense provision	($12,829)	($9,852)
1. Solvency assets	$5,116,874	$3,930,935
Solvency asset adjustment:		
Present value of special payments for the next five years	$106,891	$72,560
2. Adjusted solvency assets	$5,223,765	$4,003,495
Actuarial liability		
Present value of accrued benefits for:		
▪ active members and LTDs	$2,323,503	$1,523,142
▪ pensioners and survivors	$3,432,362	$2,926,205
▪ deferred pensioners	$63,915	$39,033
▪ additional voluntary contributions	$16	$28
3. Liabilities before exclusion of benefits	$5,819,796	$4,488,408
4. Value of excluded benefits	(1,568,553)	(1,028,215)
5. Solvency liability	$4,251,243	$3,460,193
Solvency liability adjustment	$0	$0
6. Adjusted solvency liability	$4,251,243	$3,460,193
Solvency excess (deficiency) created as at valuation date (2. – 6.)	$972,522	$543,302
Transfer ratio (1. ÷ 3.)	0.88	0.88
Ratio of solvency assets to solvency liabilities (1. ÷ 5.)	1.00	1.00

Payment of Benefits

Since the transfer ratio is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the *Ontario Pension Benefits Act* to allow for the full payment of benefits. Otherwise, the plan administrator should take the actions prescribed by the *Act*.

Financial Position on a Wind-Up Basis

The plan's hypothetical wind-up position as at December 31, 2006, assuming circumstances producing the maximum wind-up liability on the valuation date is determined as follows:

Wind-Up Position (in 000s)

	31.12.06
Market value of assets	$5,131,430
Net transfer in respect of reciprocal transfers	($1,727)
Termination expense provision	($12,829)
Wind-up assets	$5,116,874
Present value of accrued benefits for:	
▪ active members and LTDs	$2,323,503
▪ pensioners and survivors	$3,432,362
▪ deferred pensioners	$63,915
▪ additional voluntary contributions	$16
Total wind-up liability	$5,819,796
Wind-up excess (deficiency)	($702,922)

Impact of Plan Wind Up

In our opinion, the value of the plan's assets would be less than its actuarial liabilities if the plan were to be wound up on the valuation date. Based on the assumptions used in this report, actuarial liabilities would exceed the market value of plan assets by $702,922. This calculation includes a provision for termination expenses that might be payable from the pension fund.

We note that the wind-up position shown above is theoretical and does not represent the cost at which CPI indexed annuities can be purchased in today's market. Given the magnitude of the liabilities under the plan, it is not possible to settle the liabilities at any reasonable cost through the purchase of annuities due to the limited size of the annuity market and the lack of a competitive market for indexed annuities in Canada.

Pension Benefit Guarantee Fund (PBGF) Assessment

The PBGF assessment is calculated as follows:

$1 for each Ontario member	$11,668
PLUS	
0.5% of PBGF assessment base up to 10% of PBGF liabilities	$0
PLUS	
1.0% of PBGF assessment base up to between 10% and 20% of PBGF liabilities	$0
PLUS	
1.5% of PBGF assessment base over 20% of PBGF liabilities	$0
PBGF assessment	$11,668

The PBGF assessment base and liabilities are derived as follows:

PBGF Assessment Base and PBGF Liabilities

PBGF liabilities	$4,251,243	(a)
Total solvency liabilities	$4,251,243	(b)
Ontario asset ratio	100%	(c) = (a) ÷ (b)
Market value of assets	$5,129,703	(d)
Ontario portion of the fund	$5,129,703	(e) = (c) x (d)
PBGF assessment base	$0	(f) = (a) - (e)

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Funding Requirements

Current Service Cost

The estimated value of the benefits that will accrue on behalf of the active members during 2007, in comparison with the corresponding value determined in the previous valuation as at December 31, 2003, is summarised below:

Employer's Current Service Cost (in 000s)

	2007	2004
Total current service cost	$87,040	$74,565
Estimated members' required contributions	($16,555)	($14,477)
Estimated employer's current service cost	$70,485	$60,088
Employer's current service cost expressed as a percentage of members' pensionable earnings	20.3%	20.4%

An analysis of the changes in the employer's current service cost follows:

Changes in Employer's Current Service Cost

Employer's current service cost as at 31.12.03	20.4%
Demographic changes	(0.6%)
Changes in assumptions and methods	0.5%
Employer's current service cost as at 31.12.06	20.3%

Special Payments

Going-Concern Basis

The present value, as at December 31, 2006, of the monthly special payments that were determined in the previous valuation, is as follows:

Present Value of Monthly Special Payments Determined as at December 31, 2003

Type of Deficit	Effective Date	Current Special Payment	Last Payment	Present Value of Remaining Payments as at 31.12.2006
Unfunded liability	Dec. 31, 2003	$1,397,417	Dec. 31, 2018	$144,414,000
Total		$1,397,417		$144,414,000

Due to the experience loss arising since the previous valuation, a going-concern unfunded liability of $215,723,000 was created as at December 31, 2006.

In accordance with the *Ontario Pension Benefits Act*, the going-concern unfunded liability needs to be amortized over a period not exceeding 15 years. As such, special payments must be increased by $595,637 per month, until December 31, 2021 to amortize this going-concern unfunded liability.

Solvency Basis

No solvency special payments are required.

Total Special Payments

The following minimum monthly special payments must be made to the Plan to eliminate the unfunded liability as at December 31, 2006, within the periods prescribed by the *Ontario Pension Benefits Act*.

Minimum Monthly Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment
Unfunded liability	December 31, 2003	$1,397,417	December 31, 2018
Unfunded liability	December 31, 2006	$595,637	December 31, 2021
Total		$1,993,054	

Employer Contributions

There is an unfunded liability of $215,723,000 as at December 31, 2006. As such, we recommend that Hydro One Inc. make monthly contributions to the plan from 2007 to 2009, as follows:

Minimum Funding Requirements

The minimum monthly required contributions from 2007 to 2009 are as follows:

Monthly Employer Contributions
For current service: 20.3% of members' pensionable earnings
Minimum special payments for unfunded liability: $1,993,054

On the basis of the members' estimated pensionable earnings, we have estimated the minimum total employer contribution for 2007 to be $94,402,000, or $7,866,833 per month.

Maximum Eligible Contributions

The maximum eligible employer contribution is equal to the Hydro One Inc. current service cost plus the greater of the going-concern unfunded liability and the wind-up deficiency. We have estimated the maximum eligible annual contribution for 2007 to be $773,407,000 as at December 31, 2006. The portion of this contribution representing the payment of the wind-up deficiency ($702,922,000) can be increased with interest from December 31, 2006 to the date the payment is made.

Contributions for current service must be made within 30 days following the month to which they apply. Special payments to eliminate an unfunded liability or solvency deficiency must be made in the month to which they apply.

The minimum contribution requirements based on this report exceed the minimum contribution requirements recommended in the previous valuation report. Upon filing this report, Hydro One Inc. must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following December 31, 2006. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

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Actuarial Opinion

With respect to the Actuarial Valuation as at December 31, 2006
of the Hydro One Inc. Pension Plan and Fund
FSCO Registration and
Canada Revenue Agency 1059104

Based on the results of this valuation, we hereby certify that, as at December 31, 2006,

- The employer's current service cost for 2007 and subsequent years, up to the next actuarial valuation should be calculated as 20.3% of members' pensionable earnings.
- The employer's current service cost for 2007 is estimated to be $70,485,000.
- The plan would be fully funded on a going-concern basis if its assets were augmented by $215,723,000. In order to comply with the provisions of the *Ontario Pension Benefits Act*, the unfunded liability must be liquidated by monthly special payments at least equal to the amounts indicated, and for the periods set forth, below:

Monthly Unfunded Liability Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment
Unfunded liability	December 31, 2003	$1,397,417	December 31, 2018
Unfunded liability	December 31, 2006	$595,637	December 31, 2021
Total		$1,993,054	

- The Pension Benefits Guarantee Fund annual assessment under Section 37 of the Regulations to the *Ontario Pension Benefits Act* is $1 per Ontario Plan Beneficiary. The estimated PBGF assessment for 2007 is $11,668 payable no later than September 30, 2007.

- The plan has a solvency excess of $972,522,000 as at December 31, 2006. No special payments are required to be made for solvency purposes.
- As permitted under the *Ontario Pension Benefits Act,* the plan administrator has elected to exclude the value of future indexing from the solvency liabilities. The circumstances in which the plan wind up is assumed to have taken place are as follows: *unilateral termination of the pension plan.*
- The transfer ratio of the plan is 0.88. The Prior Year Credit Balance on December 31, 2006 is $0.
- In our opinion,
  - the data on which the valuation is based are sufficient and reliable for the purposes of the valuation,
  - the assumptions are, in aggregate, appropriate for the purposes of determining the funded status of the plan as at December 31, 2006 on going-concern and solvency bases, and determining the minimum funding requirements, and
  - the methods employed in the valuation are appropriate for the purposes of determining the funded status of the plan as at December 31, 2006 on going-concern and solvency bases, and determining the minimum funding requirements.
- This report has been prepared, and our opinions given, in accordance with accepted actuarial practice.
- All of the actuarial assumptions made for the purposes of the valuation were reasonable at the time the valuation was prepared.

Scott Clausen
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept 5, 2007
Date

Malcolm P. Hamilton
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Sept. 5, 2007
Date

Appendix A

Plan Assets

Sources of Plan Asset Data

The pension fund is held in trust by CIBC Mellon and is invested in accordance with the investment policy.

We have relied upon the auditors' reports prepared by Ernst and Young, for the period from December 31, 2003 to December 31, 2006 along with supplemental asset information provided by Hydro One Inc.. The assets have been reduced by an estimated transfer to Inergi LP of $194,914,000 at December 31, 2006 rather than the $127,000,000 shown in the audited financial statements of the pension fund to reflect the value of the amount that would have been transferred at December 31, 2006.

Reconciliation of Plan Assets

The pension fund transactions for the period from December 31, 2003 to December 31, 2006 are summarised as follows:

Reconciliation of Plan Assets (Market Value) (in $000)

	2004	2005	2006
January 1	$3,940,619	$4,251,291	$4,723,892
PLUS			
Members' contributions	$14,380	$14,200	$17,126
Company's contributions	$81,806	$83,019	$85,672
Reciprocal transfers	$1,102	$2,725	$204
Investment income and net capital gains (losses)	$456,696	$631,985	$568,185
	$553,984	$731,929	$671,187
LESS			
Pensions paid	$224,093	$228,220	$232,532
Lump-sum refunds	$8,171	$20,617	$20,123
Administration fees	$11,048	$10,491	$10,994
Transfer of assets	$0	$0	$0
	$243,312	$259,328	$263,649
December 31	$4,251,291	$4,723,892	$5,131,430

This asset value is adjusted to reflect a net transfer of approximately $1,727,000 payable in connection with reciprocal transfers.

We have tested the pensions paid, the lump-sum refunds and the contributions for consistency with the membership data for the plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Appendix B

Actuarial Methods and Assumptions

Actuarial Valuations Methods — Going-Concern Basis

Valuation of Assets

For this valuation, we have continued to use a smoothed market value method to determine the actuarial value of plan assets. Under this method, the difference between actual and expected equity performance during a given year are spread on a straight-line basis over 5 years.

(in 000s)

	2003	2004	2005	2006
Equity portion of assets at year-end	$2,435,708	$2,341,079	$2,898,415	$3,209,298
Rate of return earned on equities (reported by fund managers)	20.61%	12.59%	20.00%	18.21%
Change in CPI	1.99%	2.12%	2.15%	1.64%
Expected rate of return on equities (change in CPI + 6%)	7.99%	8.12%	8.15%	7.64%
Investment return loss/(gain) on equities	($280,956)	($106,772)	($310,451)	($322,710)
Carry forward of 2003 loss/(gain)	($224,765)	($168,574)	($122,382)	($56,191)
Carry forward of 2004 loss/(gain)		($85,418)	($64,063)	($42,709)
Carry forward of 2005 loss/(gain)			($248,361)	($186,271)
Carry forward of 2006 loss/(gain)				($258,168)
Total adjustment to assets				($543,339)

The asset values produced by this method are related to the market value of the assets, with the advantage that, over time, the market-related asset values will tend to be more stable than market values.

Return of Fund

Since the last valuation as at December 31, 2003, the effective annual yield on the fund has been as follows:

Year	Rate of Return on Market Value (net of expenses)	Rate of Return on Smoothed Value (net of expenses)
2004	11.4%	6.0%
2005	14.9%	7.2%
2006	12.0%	7.7%

The rates are calculated net of investment expenses and assuming that payments from the Plan have been evenly made over each period.

The average return on the smoothed value, net of investment expenses, since the last valuation at December 31, 2003 was 7.0% per year. This rate exceeds the assumed investment return of 6.0% by 1.0% per year.

Valuation of Actuarial Liabilities

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going-concern valuation, we have continued to use the *projected unit credit actuarial cost method*. Under this method, we determine the actuarial present value of benefits accrued in respect of service prior to the valuation date, including ancillary benefits, based on projected final average earnings. This is referred to as the *actuarial liability*.

The *funding excess* or *unfunded liability*, as the case may be, is the difference between the actuarial value of assets and the actuarial liability. An unfunded liability will be amortised over no more than 15 years through special payments as required under the *Ontario Pension Benefits Act*. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

This actuarial funding method produces a reasonable matching of contributions with accruing benefits. Because benefits are recognised as they accrue, the actuarial funding

method aims at keeping the plan fully funded at all times. This promotes benefit security, once any unfunded liabilities and solvency deficiencies have been funded.

As permitted by legislation, indexation benefits that would be payable if the plan were wound up have been excluded from the solvency liabilities. There is no provision in the minimum funding requirements to fund the benefits which have been excluded in determining the solvency liabilities. Therefore, in the event that the plan is wound up and the benefits that are being excluded from the solvency liabilities become payable, the plan is not expected to have sufficient funds to provide these benefits.

Current Service Cost

The *current service cost* is the actuarial present value of projected benefits to be paid under the plan with respect to service during the year following the valuation date.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age of the group remains constant.

Employer's Contribution

Accordingly, the employer's contributions for this purpose are determined as follows:

Employer's Contributions

With a funding excess	With an unfunded liability
Current service cost	Current service cost
MINUS	PLUS
Any funding excess applied to cover the employer's current service cost	Payments to amortise any unfunded liability

Actuarial Assumptions — Going-Concern Basis

The actuarial value of benefits is based on economic and demographic assumptions. At each valuation, we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them if necessary.

In this valuation, we have used the same assumptions as in the previous valuation except as noted. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations. For this valuation, we have used the following assumptions:

Economic Assumptions

Investment Return

We have assumed that the investment return on the actuarial value of the fund, net of investment expenses charged to the fund, will average 6.00% per year over the long term. This rate is equal to the long-term expected rate of return on the pension fund, reduced by a provision for adverse deviations and a provision for expenses:

Expected rate of return on the pension fund	7.18%
Provision for Adverse Deviations	(0.93%)
Provision for expenses	(0.25%)
Valuation Interest Rate	6.00%

This long-term expected rate of return is consistent with the plan's investment policy and is based on a nominal return on real return bonds plus an adjustment to reflect the impact of an equity risk premium and the correlation between the various asset classes.

Increases in Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken 2006 pensionable earnings and assumed that such earnings will increase at 3.25% per year plus an age/service dependent merit factor described later.

The previous actuarial valuation assumed pensionable earnings to be increased by 3.00% per year plus an age/service dependent merit factor per year.

Increases in the YMPE

Since the benefits provided by the plan depend on the final average Year's Maximum Pensionable Earnings (YMPE) under the Canada Pension Plan, it is necessary to make an assumption about increases in the YMPE for this valuation. We have assumed that the YMPE will increase at the rate of 3.50% per year from its 2007 level of $43,700.

The previous actuarial valuation assumed the YMPE to be increased by 3.25% per year.

Increases in the Maximum Pension Permitted under the Income Tax Act

We have assumed the maximum pension limit of $2,222.22 per year of service in 2007 under the Income Tax Act will increase by $111.11 per year of service to $2,444.44 in 2009 and at a rate of 3.5% per year starting in 2010.

The previous valuation assumed the maximum pension limit of $1,833.33 per year of service would increase to $2,000.00 in 2005 and would increase at 3.25% per year starting in 2006.

Indexation of Pensions in Payment

Pensions in payment are increased each year according to a formula related to increases in the Consumer Price Index (CPI).

For this valuation, we have assumed that the CPI will increase at the rate of 2.50% per year.

The previous actuarial valuation assumed the CPI would be increased by 2.25% per year.

Interest Credited on Employee-Required Contributions

For this valuation, we have assumed that the interest rate to be credited on employee-required contributions will represent, on average, 5.00% per annum, over the long term.

Demographic Assumptions

Retirement Age

Because early retirement pensions are reduced in accordance with a formula, the retirement age of plan members has an impact on the cost of the plan. The assumed rates of retirement are as follows:

	Percentage of Active Members Who Elect to Retire at a Given Age			
	If Eligible for an Unreduced Pension		If Eligible for a Reduced Pension*	
Age	Male	Female	Male	Female
Less than 55	15%	15%	0%	0%
55	15%	15%	2%	5%
56 to 60	25%	25%	2%	5%
61 to 64	25%	25%	7%	10%
65	100%	100%	100%	100%

* *other than an actuarially reduced pension.*

These rates have been updated from the last valuation and are based on a study of Hydro One Inc.'s experience between 2000 and 2006.

Termination of Employment

The termination rates have been updated from the last valuation and are based on a study of Hydro One Inc.'s experience between 2000 and 2006.

Sample rates of termination are as follows:

	Percentage of Members who Terminate Employment	
Age	Males	Females
15	4%	5%
20	4%	5%
25	4%	5%
30	2%	4%
35	2%	4%
40	1%	3%
45	1%	3%
50	1%	3%
55 & over	0%	0%

For employees who terminate and will qualify for an unreduced pension or have 25 or more years of continuous employment, the value includes the member's right to subsidized reductions if the pension commences before age 65 (age 60 for females hired before 1976).

Mortality

The actuarial value of a pension depends on the length of the member's life. We have assumed that mortality rates, both before and after retirement, follow the UP 1994 Table assuming generational mortality improvements. According to this table, the life expectancy for a plan member age 65 at the valuation date is 19.3 years for a man and 21.9 years for a woman.

In the previous valuation, we assumed mortality rates in accordance with the Group Annuity Mortality (GAM) Table for 1994.

Disability

We have made an allowance for projected benefits payable on retirement following a period while in receipt of long-term disability benefits. This assumption does not have a material impact on the results of the valuation.

Sample rates of disability are as follows:

Age	Percentage of Members who become Disabled
30	0.105%
35	0.110%
40	0.115%
45	0.120%
50	0.295%
55	1.000%
60	1.878%

Disabled employees are assumed to remain disabled until age 65, as few recoveries have been recorded.

Family Composition

Benefits in case of death, before and after retirement, depend on the plan member's marital status.

For this valuation, we have assumed that 90% of plan members will have an eligible spouse on the earlier of death or retirement, and that the male partner will be four years older than the female partner.

Commencement of Deferred Pensions

The actuarial liability for members who terminated employment prior to the valuation date and who elected to take a deferred pension depends on the pension commencement date.

Deferred pensions payable to employees who terminated employment after March 31, 1986 with vested rights and will qualify for an unreduced pension or who have 25 or more years of continuous employment, or who terminated in 1993 under the Voluntary Separation Program with 15 or more years of continuous employment, are assumed to commence at the earliest possible date. Deferred pensions payable to other terminated employees with vested rights are assumed to commence on their normal retirement date.

Retirement Date for Disabled Members

Members on long-term disability are assumed to retire at age 65.

Movement Within the Salary Structure

Even if the salary structure does not change from year-to-year, members' salaries increase due to promotions, the accumulation of seniority and movement within and between salary bands. Hydro One Inc. studied pay adjustments between the end of 1998 and the end of 2000. From these studies, we developed the following rates of increase.

	Salary Increases Due to Movement Within the Salary Structure*	
Age	First 4 Years of Employment	Subsequent Years
Under 25	7.0%	1.0%
25 – 29	3.0%	1.0%
30 – 34	3.5%	1.5%
35 – 39	3.5%	1.5%
40 – 44	3.5%	2.0%
45 – 49	3.5%	1.5%
50 – 54	2.0%	1.5%
55 – 59	2.0%	1.5%
60 & over	2.0%	0.0%

** Over and above any increase in salaries due to adjustments to the salary structure itself.*

Actuarial Valuation Methods and Assumptions — Solvency and Impact of Plan Wind-Up

We have used the market value of the plan's assets in our valuation of the plan for solvency and wind-up purposes.

To determine the wind-up actuarial liability, we have valued those benefits that would have been paid had the plan been wound up on the valuation date, including benefits that would be immediately payable if the employer's business were discontinued on December 31, 2006, with all members fully vested in their accrued benefits. The circumstances in which the plan wind up is assumed to have taken place are as follows: *unilaterial termination of the plan*. To determine the solvency actuarial liability, the cost of future indexing has been excluded from the solvency liabilities as permitted under the *Ontario Pension Benefits Act*.

We have considered that members not eligible for an immediate pension would be entitled to a deferred pension payable from age 65 or such earlier age for which plan eligibility requirements have been satisfied at December 31, 2006. Members whose age plus years of service equal at least 82 or those who are age 55 or over are considered to be entitled to an immediate pension, reduced in accordance with the plan rules. We have also considered that members whose age plus years of service equal at least 55 at December 31, 2006 would be entitled to a deferred pension payable from the age that would produce the greatest value if employment were to have continued for the purpose of determining eligibility for early retirement benefits. For each individual plan member, accumulated contributions with interest plus 50% of the present value of the pension accumulated after December 31, 1986 are established as a minimum actuarial liability for service after this date.

Benefits are assumed to be settled through a lump sum transfer for *members not eligible for an immediate pension*. The value of the benefits accrued on December 31, 2006, for such members is based on the assumptions described in Section 3800 – *Pension Commuted* Values of the Canadian Institute of Actuaries Standards of Practice applicable for December 31, 2006.

Benefits are assumed to be settled through the purchase of annuities for *members eligible for an immediate pension*. The value of the benefits accrued to December 31, 2006, for such members are based on an estimate of the cost of settlement through purchase of annuities to calculate solvency actuarial liabilities.

In accordance with the *Ontario Pension Benefits Act,* the members in receipt of a pension at the wind-up date as well as members who have elected to receive an immediate pension or deferred annuity must be settled through the purchase of an annuity upon the wind-up of a plan. However, given the magnitude of the liabilities under the plan, it is not possible to settle the liabilities at any reasonable cost through the purchase of annuities due to the limited size of the annuity market and the current lack of competitive market for indexed annuities in Canada.

In light of these limitations, the above basis is equal to the non-indexed annuity proxy rate determined in accordance with the Canadian Institute of Actuaries Education Note: Guidance for 2007 Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2006 and December 30, 2007 reduced by an assumed inflation adjustment. The assumed inflation assumption is based on the implied inflation derived from the difference in indexed and non-indexed commuted value rates as at the date of the valuation.

We note that the above basis is theoretical and does not represent the cost at which CPI-indexed annuities can be purchased in today's market. We expect that if an insurance company were to take on these obligations that they would demand a significantly higher price.

However, the above basis may be consistent with the price that an insurance company would charge to provide pensions that increase at a fixed rate of 2.44% per year (the estimated long-term rate of inflation implied from the difference in indexed and non-indexed commuted value rates as at the date of the valuation) instead of the actual increase in the CPI.

Actuarial Assumptions

Mortality rates:	UP 1994 projected to 2015
Interest rates for benefits to be settled through lump sum transfer (for wind-up calculations):	2.25% per year for the first 10 years following 31.12.06, 2.25% per year thereafter
Interest rates for benefits to be settled through annuity purchase (for wind-up calculations):	4.60% per year with inflation increases of 2.44% per year
Interest rates for benefits to be settled through lump sum transfer (for solvency calculations):	4.75% per year for the first 10 years following 31.12.06, 4.75% per year thereafter
Interest rates for benefits to be settled through annuity purchase (for solvency calculations):	4.60% per year
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going-concern valuation
Termination expenses:	0.25% of assets excluding the transfers*

* *This is to cover the cost of liquidating the assets and administering the wind-up.*

In a solvency valuation, the accrued benefits are based on the member's final average earnings on the valuation date; therefore no salary projection is used. Also, the employment of each member is assumed to have terminated on the valuation date; therefore, no assumption is required for future rates of disability and termination of employment. In determining the estimated termination expenses, we have assumed that the plan sponsor is solvent.

Appendix C

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2006, provided by Hydro One Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

Plan membership data are summarised below. For comparison, we have also summarised corresponding data from the previous valuation.

Membership Data

	31.12.06	31.12.03
Active Members		
▪ Number	4,047	3,833
▪ Total pensionable earnings	$323,300,891	$282,290,871
▪ Average pensionable earnings for following year	$83,925	$76,975
▪ Average years of pensionable service	18.0 years	17.9 years
▪ Average age	46.3	45.2
▪ Accumulated contributions with interest	$302,387,517	$268,871,874
Members on Long Term Disability		
▪ Number	121	117
▪ Total deemed earnings for pension purposes	$7,775,965	$6,763,125
▪ Average deemed earnings for pension purposes	$64,264	$57,804
▪ Average years of pensionable service	23.19 years	20.6 years
▪ Average age	53.8	52.1
▪ Accumulated contributions with interest	$7,520,585	$5,974,400
Deferred Pensioners		
▪ Number	360	355
▪ Total annual pension	$4,287,487	$3,791,970
▪ Average annual pension	$11,910	$10,682
▪ Average age	50.7	48.9
Pensioners		
▪ Number	5,360	5,544
▪ Total annual lifetime pension	$177,534,353	$169,203,871
▪ Total annual temporary pension	$25,154,161	$26,655,751
▪ Average annual lifetime pension	$33,122	$30,520
▪ Average age	69.5	68.0
Survivors		
▪ Number	1,780	1,771
▪ Total annual lifetime pension	$33,115,211	$29,372,044
▪ Total annual temporary pension	$465,574	$421,407
▪ Average annual lifetime pension	$18,604	$16,585
▪ Average age	77.5	76.4

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

Reconciliation of Membership

	Actives	Members on LTD	Deferred Vested	Pensioners	Survivors	Total
Total at 31.12.03	**3,833**	**117**	**355**	**5,544**	**1,771**	**11,620**
New entrants	574	1	7			582
Terminations:						
▪ transfers / refunds	(54)	(1)	(18)			(73)
▪ deferred pensions	(52)		52			
Disability	(22)	22				
Deaths	(19)	(6)		(440)	(191)	(656)
Retirements	(213)	(12)	(31)	256		
New survivor					294	294
Benefit expired				(2)	(92)	(94)
Data correction			(5)	2	(2)	(5)
Total at 31.12.06	**4,047**	**121**	**360**	**5,360**	**1,780**	**11,668**

The distribution of the active members by age and pensionable service as at December 31, 2006, is summarised as follows:

Distribution of Active and LTD Members by Age Group and Pensionable Service As at 31.12.06

Age Group	Service Group									
	0-4	5-9	10-14	15-19	20-24	25-29	30-34	35-39	40+	Total
20 - 24	34									34
	52,741									52,741
25 - 29	160	26								186
	63,436	69,753								64,319
30 - 34	137	64								201
	67,701	73,081								69,414
35 - 39	96	43	14	99	3					255
	74,687	84,670	72,164	74,622	76,445					76,227
40 - 44	91	90	21	359	243	24				828
	73,230	74,526	81,298	77,801	75,746	79,952				76,491
45 - 49	63	87	12	196	271	414	19			1,062
	75,162	91,779	80,109	77,797	79,208	82,868	86,879			81,311
50 - 54	39	69	11	98	124	356	284	6		987
	71,843	79,635	93,791	81,158	79,631	89,923	83,054	77,015		84,314
55 - 59	20	33	7	53	63	134	96	42		448
	77,296	81,071	90,067	86,238	80,885	89,221	84,265	79,009		84,557
60 - 64	13	20	5	34	32	34	12	8		158
	74,768	84,685	71,474	78,495	74,087	84,988	76,944	74,162		78,917
65-69		2		1	1	3	1	1		9
		100,744		58,008	103,179	57,707	62,538	76,177		74,946
Total	653	434	70	840	737	965	412	57		4,168
	69,076	80,390	81,406	78,354	78,080	86,277	83,285	78,069		79,433

The distribution of the inactive members by age as at December 31, 2006, is summarised as follows:

Distribution of Inactive Members By Age Group as at 31.12.06

	Deferred Pensioners		Pensioners		Survivors	
Age	Number	Average Pension	Number	Average Pension	Number	Average Pension
<40	16	3,904			5	13,355
40 - 44	40	5,195			3	8,312
45 - 49	94	11,318			16	12,189
50 - 54	112	16,175	166	35,097	37	15,929
55 - 59	68	12,455	921	36,038	56	17,561
60 - 64	26	10,753	907	35,339	77	19,893
65 - 69	4	3,825	744	32,432	128	19,627
70 - 74	0	0	781	31,185	247	19,629
75 - 79	0	0	896	33,092	406	20,317
80 - 84	0	0	578	31,880	366	18,132
85 - 89	0	0	273	28,413	267	18,118
90 - 94	0	0	75	22,984	126	15,909
>95	0	0	19	22,219	46	13,828
TOTAL	360	11,910	5,360	33,122	1,780	18,604

Appendix D

Summary of Plan Provisions

The following is a summary of the main provisions of the Plan and its supporting documents which are relevant to the actuarial valuation.

Membership

The following categories of employees are members of the Plan:

(a) All regular employees.

(b) Employees for whom the office and Professional Employees International Union was the bargaining agent prior to July 30, 1982.

(c) Employees who became continuing construction clerical employees after July 29, 1982 and before August 8, 1984.

(d) Employees who have completed three months of continuous employment as a probationary employee.

Any other employee, with the exception of construction trades, machinists, and hotel and restaurant employees, who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the YMPE (see note on next page) in each of the two previous calendar years, may elect to become a member of the Plan.

Other members include pensioners, terminated employees with deferred pensions, and employees receiving long term disability benefits.

Note: "YMPE" is the Year's Maximum Pensionable Earnings as defined under the Canada Pension Plan.

Normal Retirement Date

(a) Female members whose continuous employment commenced prior to January 1, 1976: The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her sixty-fifth birthday.

(b) All other members:
The first day of the month coincident with or next following the attainment of age 65.

Amount of Accrued Pension

Life Pension

(a) 2% of the member's "high three-year average" (high five-year average for management employees hired on or after January 1, 2004 and Society employees hired on or after November 17, 2005) (see note below) for each year of credited service, subject to a maximum of 35 years

LESS

(b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service included in (a) above subsequent to December 31, 1965. This factor has been reduced from 0.625% to 0.50% for members of the Power Workers Union (PWU) and for Society members hired prior to November 17, 2005.

Bridge Pension

For everyone except management employees hired on or after January 1, 2004 and Society members hires on or after November 17, 2005, 0.625% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. This is generally payable until age 65.

Management employees hired on or after January 1, 2004 and Society members hired after November 17, 2005 are not entitled to receive a bridge benefit from the Plan.

Note: "High three-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the thirty-six consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPE's during the sixty consecutive months when the base earnings were highest.

Early Retirement

An employee may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the employee's age and years of continuous employment is equal to or greater than 82 (85 for management employees hired on or after January 1, 2004 and Society employees hired on or after November 17, 2005).

A female employee whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other employee with 15 or more years of continuous employment but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the employee's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the employee's normal retirement date.

Otherwise, an employee may retire prior to age 60 with 25 or more years of continuous employment, but within 10 years of normal retirement date. In such a case, the employee's accrued pension is reduced by 3% for each year by which early retirement precedes age 60.

An employee, who does not qualify under any of the previously mentioned early retirement provisions and who has at least two years of Plan membership, may retire within 10 years of normal retirement date. In such a case, the pension is the actuarial equivalent of the member's deferred pension.

A terminated employee with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination.

A terminated employee with a deferred pension, who terminated after March 31, 1986, with 25 or more years of continuous employment has the same early retirement provisions as those in effect for active employees at the date of termination.

Otherwise, a terminated employee with a deferred pension, who terminated with 15 or more years of continuous employment, or who terminated with 2 or more years of Plan membership after 1987, may receive a pension within 10 years of normal retirement in accordance with the rules in effect on the date of termination. In such a case, the pension is the actuarial equivalent of the member's deferred pension.

Pension Increases

Pension increases of 100% (75% for management employees hired on or after January 1, 2004 and Society employees hired after November 17, 2005) of the increase in the CPI (Ontario) will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions.

Disability

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Contributions

By the Employees

The employees contribute at the following rates until they complete 35 years of credited service:

(i) 4% of base annual earnings up to the YMPE,
and
6% of base annual earnings in excess of the YMPE.

Society members are required to contribute an additional 0.5% of base annual earnings when the ratio of solvency assets to solvency liabilities is less than 106%.

Death Benefits

For purposes of describing the death benefits and excess contributions below, the term "spouse" would also refer to same sex partners in addition to its traditional definition.

Death Before Retirement

(a) Benefits in respect of Continuous Employment Prior to 1987

(i) If the member has completed 10 years of continuous employment, the surviving spouse or dependent child is entitled to a survivor's pension. The survivor's pension is an amount equal to 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement. The survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest.

(ii) Otherwise, a payment of the member's contributions with interest is made to the beneficiary or estate.

(b) Benefits in respect of Continuous Employment After 1986

(i) If the member has less than 2 years of Plan membership and has not completed 10 years of continuous employment, a payment of the member's contributions with interest is made to the beneficiary or estate.

(ii) If the member has less than 2 years of Plan membership, but has completed 10 years of continuous employment, the surviving spouse is entitled to a survivor's pension as described in (a)(i) above.

(iii) If the member has at least 2 years of Plan membership, but has not completed 10 years of continuous employment, the surviving spouse is entitled to receive the commuted value of the member's deferred pension. In lieu of such payment, the surviving spouse may elect to receive an immediate or deferred pension of equivalent commuted value. If there is no surviving spouse, a payment of the commuted value of the member's deferred pension is made to the beneficiary or estate.

(iv) If the member has at least 2 years of Plan membership and has completed 10 years of continuous employment, the surviving spouse is entitled to the greater of an immediate pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, or an immediate pension with commuted value equivalent to the commuted value of the member's deferred pension. In lieu of this pension, the surviving spouse may elect to receive the commuted value of the member's deferred pension or a deferred pension of equivalent commuted value. If there is no surviving spouse, the dependent children are entitled to a pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, payable to age 18 (longer if disabled or in full-time attendance at a school or university). If there is no surviving spouse, a payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.

Death After Retirement

A survivor's pension, an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse or dependent children, subject to other options chosen at the time of retirement.

Termination of Employment

(a) Benefits in respect of Continuous Employment Prior to 1987

(i) The member is entitled to a refund of all of the member's pre-1987 contributions with interest, subject to (iv) below.

(ii) A member, who has at least one year of Plan membership, may elect to receive, in lieu of (i) above, the pension accrued prior to 1987 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

(iii) A member, who has at least 10 years of Plan membership, may elect to receive, in lieu of (i) or (ii) above, a cash payment of 25% of the commuted value of the pension accrued prior to 1987, with 75% of such pension being paid at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

(iv) A member, who has both attained age 45 and completed 10 or more years of continuous employment, may not elect to receive a refund of contributions in respect of service between January 1, 1965 and December 31, 1986. The member may, however, elect to receive, in lieu of (ii) or (iii) above, a refund of the member's contributions to the Fund prior to 1965 together with credited interest plus 25% of the commuted value of the pension accrued after 1964 but prior to 1987, with entitlement to 75% of such pension being paid commencing on the normal or early retirement date ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. The member may elect to transfer (see note below) the greater of the commuted value of the 75% pension or 75% of the member" contributions with interest made after 1964 but prior to 1987.

(b) Benefits in respect of Continuous Employment After 1986

(i) A member is entitled to a refund of the member's post-1986 contributions with interest, subject to (iii) below.

(ii) A member, who has at least one year of Plan membership, may elect to receive, in lieu of (i) above, the pension accrued after 1986 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

(iii) A member, who has at least two years of Plan membership, may not elect to receive a refund under (i) above. The member may, however, elect, in lieu of (ii) above, to transfer (see note below) the commuted value of the deferred pension.

Note: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Excess Contributions

Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the deferred pension accrued after 1986 is refunded to the member (to the spouse, beneficiary or estate, in the case of death).

Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987.

Maximum Benefits

The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act.

Appendix E

Employer Certification

With respect to the report on the actuarial valuation of the *Hydro One Inc. Pension Plan and Fund*, as at December 31, 2006, I hereby certify that, to the best of my knowledge and belief:

- a copy of the official plan documents and of all amendments made up to December 31, 2006, were provided to the actuary;
- the membership data provided to the actuary include a complete and accurate description of every person who is entitled to benefits under the terms of the plan for service up to December 31, 2006, and
- all events subsequent to December 31, 2006 that may have an impact on the results of the valuation have been communicated to the actuary.

SEPTEMBER 10, 2007
Date

Signed

Beth Summers
Name

Ontario Energy Board (Board Staff) INTERROGATORY #77 List 1

Interrogatory

Ref: Exhibit C1 Tab 4 Schedule 2/Issue 3.1
On page 6, Table 1 presents "Total Incremental Cost Saving – Distribution."

a. Please provide tables for OM&A and capital expenditures that illustrate the cost savings initiatives and outline the description of the implementation plan for each initiative, costs, and cost savings realized for 2004 to 2008 period.
b. Please clarify if Hydro One has offset net annual OM&A and capital expenditures for 2007 and 2008 by the amounts shown in Table 1
c. Please quantify the total savings for each year 2004 to 2008 and show m as annualized productivity %.

Response

A. For a list of the major initiatives implemented for the 2004 to 2008 period, please see refer to Exhibit C1, Tab 4, Schedule 2. A table is provided below showing cost savings for initiatives for the 2004 to 2008 period.

Initiatives	2004	2005	2006	2007	2008
Developing a more multi-skilled workforce	0.0	0.0	0.4	0.0	0.0
Increased staffing flexibility	8.3	0.8	2.8	0.2	0.0
New tools and technologies	1.7	3.8	0.7	0.7	0.0
Implementation of new processes & tools in the field	1.2	0.0	0.0	0.0	0.0
Targeted savings from strategic sourcing initiatives	5.1	2.2	3.4	0.9	0.9
Continued Outsourcing of non-core work activities	0.0	2.4	1.4	0.5	1.6
Improvement to collective agreements	0.0	7.4	0.0	0.0	0.0
Smart Meter Installation	0.0	0.0	0.0	0.0	4.4
Other Savings	6.8	1.9	1.9	2.0	2.8
Total	**23.0**	**18.6**	**10.5**	**4.4**	**9.6**

B. Yes.

C. Please refer to Exhibit C1, Tab 4, Schedule 2, Page 6, Table 1.

Ontario Energy Board (Board Staff) INTERROGATORY #78 List 1

Interrogatory

Ref: Exhibit C1 Tab 4 Schedule 2/Issue 3.1
On page 9, Hydro One states, "Despite a projected 40% increase in Hydro One Networks Distribution and Transmission businesses' work program expenditures between 2006 and 2008, whereas over this same period the regular staff count is expected to only have grown by 23% and total staff resources (regular and non-regular) by 34%. This is an indication that Hydro One is getting more work done without a corresponding increase in resource levels".

a. Please clarify if non-regular staff includes contract staff, but excludes external consultants, contractors, and outsourcing.
b. If non-regular staff excludes external consultants, contractors, and outsourcing, please provide the percentage of increase in these resources between 2006 and 2008 for these work programs.

Response

a. Yes. Non-regular staff includes contract staff but excludes external consultants, contractors, and outsourcing.

b. Hydro One Distribution secures where appropriate, the accomplishment of work by consulting services, contractor services and general outsourced services which consist of various mixtures of external labour, materials, equipment rentals and other factor costs. In doing so, Hydro One Distribution follows a process of procuring, monitoring and receipting the packages of work contracted for. It does not do so at the factor input level and as such does not maintain information at this level.

Ontario Energy Board (Board Staff) INTERROGATORY #79 List 1

Interrogatory

Ref: Exhibit C1 Tab 4 Schedule 2/Issue 3.1
On page 12, Hydro One states, "It is expected that the use of mobile work applications and the use of GIS information will increase field force productivity. By leveraging all the new data which implementation of the IT Architecture Strategy and the smart meters program will deliver, Hydro One will become an even more proactive company in managing its assets. The extent of these future efficiency and productivity improvements is not yet fully known; preliminary work is being carried out to assess how best to use integrated technology platforms."

a. Please clarify if Hydro One quantified the future efficiency and productivity improvements during the evaluation and selection of IT Architecture Strategy and Cornerstone program. Please describe the methodology for evaluation of the program and estimated pay-back period.
b. If Hydro One did not quantify the future efficiency and productivity improvements during the evaluation and selection of IT Architecture Strategy and Cornerstone program, please identify the criteria that Hydro One used to assess and select the programs and the means by which the programs were justified. Please describe the methodology for evaluation of the program if the benefits are not quantified.
c. Please clarify what the 'filed force productivity' means in terms of OM&A cost reduction and how its savings would reflect in cost reduction to the rate payers in 2008 and beyond.
d. If "future efficiency and productivity improvements" mean financial benefits, please sate if the financial gain is of one-time or ongoing nature and the years the savings are achieved.

Response

a. The IT Architecture Strategy is guided by the principles provided at Page 7 Exhibit D Tab 3 Schedule 5. One of the principles is the replacement of end of life applications, as is currently being undertaken in the integrated enterprise platform replacement which is the Cornerstone Project.

The IT Architecture Strategy provides guidance for IT upgrades and for the purchase of IT systems. The IT spend related to sustainment, system and software refresh and maintenance both OM&A and Capital is justified and reviewed through the work program prioritization process described at Exhibit A Tab 14 Schedule 5. Business cases are prepared by the Lines of Business to support specific application technology

investments for new applications. Pay back periods vary based on the nature of the investment.

The IT Enterprise Strategy is a strategy to replace the existing end of life best of breed applications with an integrated suite of applications which will allow for the connectivity and interflow of financial and operations performance data (Cornerstone). It is intended that data and information collected or available through GIS systems and information and data collected through mobile applications would be made available to the users of the enterprise systems to allow them to better perform their work. It is also expected that system information will be made available from new applications such as the smart meter application and that this information would also be available to integrate with both enterprise business and operations systems.

For Cornerstone Phase 1, Hydro One first selected the potential winner from its RFP process. With that Company, Hydro One negotiated and signed the Terms and Conditions for the overall project and a Statement of Work for the Discovery phase of the project. During the Discovery phase, future efficiency and productivity improvements for Cornerstone Phase 1 were developed. These savings were presented to the Hydro One Board of Directors as part of gaining approval for Cornerstone Phase 1. Following the Hydro One Board's approval, the final Statement of Work covering the rest of Phase 1 based on a fixed price was signed with the winning supplier.

For Cornerstone Phase 1, there was no estimated pay-back period calculated explicitly as it was initially considered to be a replacement of an out of date unsupported legacy system. However, corporate savings totaling $200 M to the end of 2015 have been identified (see Exhibit D1 Tab 3 Schedule 5 Updated December 18, 2007 page 21 lines 24-25 and the response to Exhibit H Tab 1 Schedule 38) based on a net investment cost of $144 M (see Exhibit D2 Tab 2 Schedule 3 #IT1).

b. Business cases are used to justify investments in IT applications and technology. These cases are assessed on both their qualitative and quantitative aspects before receiving appropriate corporate review and approval to proceed. The future efficiency and productivity improvements for Cornerstone Phase 1 were quantified, as per (a) above.

c. The use of mobile work applications and the use of GIS information that will lead to increased field force productivity will not be fully realized until Cornerstone Phase 3 – EAM tools are fully in place. As a result, an estimate of the full OM&A savings expected will not be available until the conclusion of the Discovery part of Cornerstone Phase 3. However, initial savings will be achieved through the Leverage

Technology and Information Systems savings from implementing Cornerstone Phase 1 (see response to OEB staff interrogatory Exhibit H Tab 1 Schedule 38). Savings would be reflected in lower costs than otherwise possible to the ratepayers in 2009 and beyond through increased throughput, completed additional work and improvement in the condition of Hydro One's asset base.

d. Please refer to the response to OEB staff interrogatory Exhibit H Tab 1 Schedule 38 part d).

The future efficiency and productivity improvements are not financial gains even though they are quantifiable in financial terms. These are, as stated, efficiency and productivity improvements and are of an ongoing nature which will enable Hydro One to deliver future work programs to ratepayers within a 3rd Generation IRM environment.

Ontario Energy Board (Board Staff) INTERROGATORY #80 List 1

Interrogatory

Ref: Exhibit C1-4-1 Attachment B and Table 1/Issue 3.1
On page 1, Hydro One states, "The 2008 cost for Supply Chain services is $26.5 million, with these costs allocated to work programs and projects through the material surcharge rate."

a. Please identify how much of the $26.5 million is attributed to Hydro One Distribution?
b. Please identify any amounts attributed to the Hydro One Distribution that are one-time costs.

Response

a. Of the $26.5 million, $12.2 million is allocated to Hydro One Distribution

b. There are no one-time costs attributed to Hydro One Distribution.

Ontario Energy Board (Board Staff) INTERROGATORY #81 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
On page 3, Table 1, Hydro One provides "Allocated Distribution Shared Services and Other Costs." These costs were $23.3 million and $21.2 million in 2005 and 2006 respectively, and projected to increase to $91.9 million in 2007 and $66.9 million in 2008.

What are the reasons for the large increases in 2007 and 2008 compared to 2005 and 2006? What are the key drivers for the increase in 2007 and 2008 costs for each category listed in the table, i.e. Common Corporate Functions and Services, Asset Management, Information Management Services, Cost of Sales and Other Shared Services?

Response

In general, the increase in 2007/2008 as compared to 2005/2006 is due to work program support in the Common Corporate Functions and Services, Asset Management and Information Services groups. In addition to this, there has also been a reduction in the level of credit adjustments in the Other Shared services category primarily related to the impact of the Board decision on pension costs in EB-2005-0368.

Common Corporate Function and Services
The cost increase in 2007 and 2008 compared to 2005 and 2006 is primarily due to:
Increased costs related to Bill 198 and securities compliance programs, increased communication costs, regulatory compliance requirements, theft of power program, human resources support for increased staffing, and other new programs.

Details of the cost changes for each of the CCF&S functions are described throughout Exhibit C1, Tab 2, Schedule 6.

Asset Management
As discussed in Exhibit C1, Tab 2, Schedule 6, page 3, Table 1, for the years 2004 and 2005, Asset Management costs were lower as certain program costs, including facilities and work scheduling, were charged directly to work programs through standard labour rates.

Information Management Services
As discussed in Exhibit C1, Tab 2, Schedule 6, Section 4, the increase primarily relates to the impact of Capital Projects, specifically projected work primarily associated with the implementation of the Cornerstone project.

Cost of Sales

There is a decrease in Cost of Sales due to a shift in customer responsibility for costs associated with new connections and system reinforcements as per OEB directives. As well, Hydro One Distribution provided support to Florida Power during hurricanes which did not recur in 2007. Please see Exhibit C1/Tab 2/Schedule 6 Section 5.0 for further details.

Other Shared Services

The primary factors contributing to the changes in the "Other Shared Services" category are due to the impact of the Board decision on pension costs in EB-2005-0368 under which pension costs were deferred until May 1, 2006, changes in the capitalized overhead credit, and Distribution rate hearing preparation costs. For further details, please see Exhibit C1/Tab 2/Schedule 6.

Ontario Energy Board (Board Staff) INTERROGATORY #82 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6 and Exhibit A Tab 2 Schedule 2/ Issue 3.3
On page 5 of 7 of Exhibit A Tab 2 Schedule 2, for "Shared Services & Other Costs," a 2006 Board Approved amount of $67.9 million is shown versus a 2006 Actual of $21.2 million.

Please explain the variance in the context of Hydro One's 2007 and 2008 forecasts of these amounts of $91.9 and $66.9 million in this application, as shown in Exhibit C1 Tab 2 Schedule 6, Table 1. Please explain stating why the present forecast is likely to be correct given the variance to actual of the 2006 forecast, being $47 million below the $68 million 2006 Board approved and why this situation is not likely to recur in 2007 and 2008.

Response

The following table shows the 2006 Board Approved amount as compared to 2006 actual, as well as corresponding amounts for the 2007 bridge and 2008 test years:

Allocated Distribution Shared Services and Other Costs ($ Millions)

	2006			Bridge	Test
Description	**Board Approved**	**Actual**	**Difference**	**2007**	**2008**
Common Corporate Functions and Services	35.5	33.2	(2.3)	35.7	40.5
Asset Management	39.3	40.9	1.6	38.1	46.3
Information Management Services	45.4	46.8	1.4	51.3	52.6
Cost of Sales	7.0	6.6	(0.4)	6.9	5.9
Other Shared Services	(59.3)	(106.3)	(47.0)	(40.1)	(78.3)
Total	**67.9**	**21.2**	**(46.7)**	**91.9**	**66.9**

The differences between 2006 Board Approved and 2006 Actuals can be primarily attributed to the "Other Shared Services" category.

The reasons for the variance between 2006 Board Approved and Actual in the "Other Shared Services" category include: the impact of the Board decision on pension costs in EB-2005-0368, under which pension costs were deferred until May 1, 2006; an increase in overheads capitalized associated with a higher level of capital spending; deferral of smart meter costs and a higher than planned level of environmental provision spending reclassified to amortization. Corporate Overhead, Environmental Provision and Indirect Depreciation amounts are established, reviewed and approved as part of the annual budget process. Actual results for these amounts could be different from plan as a result of work program and operational decisions during the year. The pension and smart meter impacts are non-recurring.

Ontario Energy Board (Board Staff) INTERROGATORY #83 List 1

Interrogatory

Ref Exhibit C1 Tab 2 Schedule 6/ Issue 3.4
Page 4, Table 2 provides a breakdown of "Shared Services and Other Costs." The total amount to be allocated between transmission and distribution is shown as $148.5 million and includes shared services in the areas of "Common Corporate Functions and Services," "Asset Management," "Information Management Services," "Cost of Sales," and "Other Shared Services."

In Hydro One's recent transmission rate application, an equivalent table was presented in Exhibit C1 Tab 2 Schedule 5 Page 4. The version of this table in the updated February 23, 2007 evidence showed a total amount to be allocated for 2008 of $233.0 million, which is $84.5 million higher than is being incorporated in the distribution application. The major reason for this difference appears to be that the transmission application included customer care costs as a shared service and the distribution application does not. Please provide a complete explanation for this change including whether or not these costs are being recovered in a different manner through the present application and if so, how and what the amount of recovery is.

Response

The Customer Care work program is primarily Distribution related, therefore merited its own section in the Distribution submission (Ex. C1, Tab 2, Sch. 5) and was not included within the Shared Services & Other Costs section. In the Transmission hearing EB-2006-0501 (Ex. C1 Tab. Sch. 5) the Transmission component the Customer Care work program was $1.6M of a total $106.8M program, so it was included in the Shared Services and Other Costs as it did not warrant a separate section to describe the programs in depth. There is no change to the way these costs are being recovered.

Ontario Energy Board (Board Staff) INTERROGATORY #84 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.4
Page 6, Table 3 provides the 2008 allocation to Distribution of CCF&S Costs.
Please state whether there have been any changes in the allocation percentages to distribution since the 2006 filing and, if so, please state what they are and provide an explanation and rationale for them.

Response

There has been a shift of 3.0 percentage points in the allocation percentage to Distribution due to refreshes of time studies, updates of specific cost drivers such as number of workstations and telephones, and an update of actual financial results.

Ontario Energy Board (Board Staff) INTERROGATORY #85 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
Page 37, Table 13 provides a breakdown in the costs of the Asset Management Function. This table shows an increase in these costs, before allocation to distribution from $93.8 million in the 2007 Bridge Year to $118.9 in the 2008 Test Year, an increase of 27%. In Hydro One's recent Transmission rate filing, EB-2006-0501, Exhibit C1 Tab 2 Schedule 5, Page 42, updated February 23, 2007 these same costs were shown as $97.5 million and $96.4 million respectively. In this context, please explain the 27% increase that is contained in the present application.

Response

The increase in costs, is related to additional efforts and activities to support the effective delivery of Asset Management activities including the development of asset strategies and investment plans for the distribution business that contribute to moving the Distribution business to first quartile reliability on a like-for-like basis and undertaking initiatives to increase customer satisfaction to 90% by 2010.

In general the cost increases are primarily driven by:

- The necessary increase in Distribution OM&A and capital work programs resulting in the need for more asset management experts to develop the required least cost plans and the work scope and specification documents.
- Increased regulatory work load related to rate hearings, facility approvals, EAB related proceedings, NERC, NPCC requirements. (See also H-1-68.)
- Increased work requirements associated with Pre-IPSP projects, near-term projects included in the IPSP and support for IPSP approvals.
- Compliance activities including Bill 198 programs, IESO compliance related programs precipitated by local Market and NERC requirements.
- Succession planning / demographics planning (i.e. dealing with large volume of planned and actual staff attrition) and pre-hiring to provide over-lap with experienced staff to ensure business continuity.
- The Cornerstone project which requires experienced staff to ensure business processes will be streamlined to improve business efficiency.

More specifically the reasons for the increases in the key contributing units are due to:

System Investment: (Increased by $9.5M)

- Increasing asset sustainment needs due to aging infrastructure

- Increased number of generation connection applications. (We received approximately 20 – 30 applications per year in 2004 – 2005, whereas from 2006 to the end of February 2008 we have received approximately1800 applications for either Initial Feasibility Assessments or full Connection Impact Assessments (CIA). Of this 1800, approximately half are for full CIAs. Four hundred and forty-eight projects that are within Hydro One's thresholds, are due to have CIAs done. [See also Interrogatory Response H-1-21])
- Increased regulatory activities, orders and expectations
- Cornerstone
- Enhancement of System Investment deliverables (e.g. multi-year releases)
- Succession planning initiatives
- Increased system development due to IPSP recommendations, local load growth and new generation (not necessarily generation connections on the distribution system)
- Increased reliability standards and compliance requirements
- Enhancement of System Investment deliverables (e.g. initiatives to maximize project and program execution)

Facilities and Real Estate: (Increased by $6.5 M)

- New employee workspace accommodation requirements and staffing-related costs
- Investments to ensure facilities continue to meet health and safety requirements.
- Increased costs for facility rent and utilities and increased cost of materials for facilities being constructed.

Business Integration: (Increased by $4.8M)

- Additional planning and reporting activities related to the larger work program and increasing complexity of the business and industry
- Increase activity in the deployment of the time reporting changes in the field
- Increased activity in the area of information assets in terms of keeping track of detailed changes in the system configuration
- Requirement to support the Cornerstone initiative on an on – going / production basis

Strategy and Development : (Increased by $3.7M)

- Increased activities to support development and delivery programs related to conservation and demand management, smart meters and smart network.

Work Program Optimization : (Increased by $0.9M)

- Work volume increase relating to Tx capital program increases,
- Expansion of knowledge management system into E&CS engineering division
- Support for Cornerstone.

Ontario Energy Board (Board Staff) INTERROGATORY #86 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
On page 81, the discussion of the Capitalized Overhead Credit states that "The overhead credit has increased from the 2004 level due to the higher level of capital spending."

a. Please confirm that this statement refers to the increase in this amount in 2004 from a reduction in OM&A expense of $45 million to a reduction of $59.8 million in 2006. If not, please state what increase it is referring to.
b. In the context of the statement quoted above, please state why the amount of this credit is decreasing from $59.8 million in 2006 to $47.7 million in 2008 when capital expenditures are increasing.

Response

a. Confirmed.

b. The 2006 capitalized overhead credit of $59.8 million required a true-up adjustment of $14.4 million under the OEB accepted Rudden methodology. If the 2006 capitalized overhead credit was adjusted for the E-Factor, the result would be a $45.4 million capitalized overhead credit in 2006. After this true-up adjustment, the $47.7 million capitalized overhead credit in 2008 is higher than the adjusted 2006 level. Please refer to H-1-16 for more information on the E-Factor.

Ontario Energy Board (Board Staff) INTERROGATORY #87 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
On page 82, the Environmental Provision adjustment is discussed.

a. Please state why this provision increased from $7.1 million in 2005 to $11.6 million in 2006 and then is forecast to drop to $6.3 million and $7.9 million in 2007 and 2008 respectively.
b. Please provide a fuller explanation of the statement that "The resultant impact on OM&A expense of this environmental work is nil, since the amortization expense is grouped with "Depreciation and Amortization" on the operating statement and the balance is transferred from OM&A to Depreciation expense."

Response

a. Hydro One's risk-ranking system has identified sites that require further assessment. Each year a number of sites are selected based on there risk ranking and have a detailed assessment performed to determine the degree of contamination. Pending the level and extent of contamination found at each site, Hydro One will perform further assessment, remediation, or conclude the assessment. Based on these detailed assessments, sites requiring remediation are scheduled for remediation. The environmental provisions will vary each year, depending on the type and extent of work required found during the remediation phase – i.e. if more contamination is found than was expected, or if the extent of contamination is higher than was expected, the remediation effort required will be greater.

   The provision values in 2005, 2006 and 2007 are actuals while 2008 is a test year forecast. The increased cost in 2006 is due to more contamination found during land remediation than expected and more PCB contaminated waste found than expected in that year versus our expectation for that year. The forecast decreases from this level in 2008 due to our expectation of the level of contamination we will find on the sites to be remediated in 2008.

b. Hydro One's environmental regulatory asset exactly corresponds to its environmental liability. As environmental expenditures occur, both the asset and liability are reduced. Based on actual spending, the liability is drawn down and the related regulatory asset is amortized to expense. OM&A is not affected however Revenue Requirement is.

Ontario Energy Board (Board Staff) INTERROGATORY #88 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
Page 83, Table 33 provides distribution deferred pension costs for the 2004 to 2008 period.

a. Please state whether or not Hydro One's pension plan was in a deficit or surplus position as of December 31, 2006
b. Please explain why there is a zero amount shown for the 2007 Bridge and 2008 Test year for deferred pension credit.

Response

a. The pension plan was in a deficit position as at December 31, 2006

b. Prior to May 2006, Hydro One was deferring into a regulatory asset the operating cost portion of pension costs related to the Distribution business (RP-2004-0180). This was reflected as a deferred pension credit.

The deferral of pension costs ceased when the Board approved new distribution rates in April 2006, effective May 1, 2006. As the new rates allowed Hydro One Distribution to recover their annual pension costs and amounts accumulated as a regulatory asset, the deferral account ceased on April 30th, 2006. Thus, a zero amount is shown for the 2007 Bridge and 2008 Test year for deferred pension credit.

Ontario Energy Board (Board Staff) INTERROGATORY #89 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
Please provide for each of the 2006 historical, 2007 bridge and 2008 test years, the dollar amount of services purchased from non affiliates and the percentage amount of total expenses that this represents.

Response

Please see the following table for Hydro One Networks Inc. [(b)]:

Services Purchased from Non-affiliates

(in $ Million)	2006 Historic	2007 Bridge	2008 Test
Services Purchased [(a)]	208	282	*
OM&A and Capital Costs	1,573	1,942	2,200
Percentage	13%	15%	*

* not available as not awarded

(a) Comprised of Inergi, consulting, operational and professional services.

(b) Includes Distribution and Transmission.

Ontario Energy Board (Board Staff) INTERROGATORY #90 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
This section makes reference to a number of services, which are outsourced to non-affiliates, most notably Inergi LP, but also others such as Mercer Pension Administration System. Please provide for all services and products purchased from non-affiliates other than Inergi LP for the 2006 to 2008 period: (i) identity of each company transacting with Hydro One, (ii) summary of the nature of the activity transacted, (iii) annual dollar value in aggregate of transactions, and (iv) description of specific methodology used in determining the price.

Response

The table below contains companies who have provided services for Hydro One Networks Inc.

Consulting and Professional Services (a)			
(i) **Company Name**	**(ii)** **Nature of Activity**	**(iii)** **(b)**	**(iv)** **Price Determination**
Accenture Inc.	Professional Services		RFP Process
Acres International Limited	Engineering and Contract Staff		RFP Process
ARI Financial Services Inc.	Operational		RFP Process
Asplundh Canada	Operational		RFP Process
Capgemini	Professional Services		RFP Process
CEA Technologies Inc.	Engineering		Single Source Negotiation
Conestoga Rovers & Associates	Environmental		RFP Process
Deloitte Consulting	Information Technology		RFP Process and Single Source Negotiation
Eagle Professional Resources	Professional Services		RFP Process
Emex Systems Inc.	Professional Services		RFP Process
Kinetrics Incorporated	Research and Development		RFP Process and Single Source Negotiation
KPMG LLP	Finance Services		RFP Process
MGA Computer Consulting Ltd.	Engineering		Single Source Negotiation
O'Connor Associates	Environmental		RFP Process

Consulting and Professional Services (a)			
(i) **Company Name**	**(ii)** **Nature of Activity**	**(iii)** **(b)**	**(iv)** **Price Determination**
Ontario Line Clearing	Operational		RFP Process
Procom Consultants Group Ltd.	Professional Services		RFP Process
SAR Associates	Information Technology		RFP Process
Seacor Environmental	Environmental		RFP Process
Stantec Consulting Ltd.	Environmental		RFP Process
Tamarack Tree Services	Operational		RFP Process
Wardrop Engineering Inc.	Engineering		RFP Process

(a) Includes companies who have provided services over $1 million in either 2006 or 2007. Contracts for 2008 have not yet been awarded.
(b) This information is considered commercially confidential

Ontario Energy Board (Board Staff) INTERROGATORY #91 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
Attachment "A" provides a summary of Hydro One Inergi CCF&S 2008 Costs. Please provide a more detailed description of the approaches which are described briefly in the column "Selection of Cost Driver."

Response

Please see table below:

Hydro One Inergi CCF&S 2008 Costs

CCF&S	Selection of Cost Driver	Approach Used for Selection of Cost Driver
Customer Support Operations	Dx function per OEB	All inbound calls and correspondence related to Dx customers, therefore directly assigned to Dx
	Activity analysis	Physical count of # of bills issued to Dx versus Remotes customers
	Activity analysis	Assessment of effort required for Tx vs Dx related timesheets.
	Analysis- other activities supported	Activity analysis of other activities performed by CSO.
Supply Management Services	Related to O&M and Capital costs incurred	Purchasing costs are related to OM&A and Capital work program, Brampton not included
	Related to transport of items purchased	Transportation costs support total OM&A and Capital work program, Brampton not included
	Related to asset disposal	Asset disposal is related to total gross plant, excluding Brampton, Telecom & Remotes
	Opportunities to save in Purchasing	Savings opportunities will apply to all areas of work program, therefore use total OM&A and Capital work program, Brampton & Telecom not included
	Related to assets	Warehouse operations costs are more related to split of assets rather than work program.

CCF&S	Selection of Cost Driver	Approach Used for Selection of Cost Driver
	Roughly proportional to other activities	Other department activities is allocated based on weighted average allocation of other SMS activities as above
		Goes to material surcharge which is part of labour rate.
Finance	Physical units (c)	Allocation done based on previous year number of invoices processed
	Physical units (c)	Allocation done based on previous year number of bills issued to customers for non-energy A/R
	Related to Fixed Assets	FA processing includes capitalization, retirements, sales & transfers; therefore better related to gross utility plant rather than current year work program
	Related to both non-energy revenue and assets	Revenues (excluding Cost of Power flow-through) are designed to recover all appropriate costs, including return in combination with assets (50%/50%), represents a good allocation methodology that combines elements of current work program with existing as
	Related to number of employees	Pension support costs are related to the number of employees assuming an even age distribution
	Management of Inergi costs	Inergi Corp. Finance is allocated as a second tier allocation based on total work program.
Human Resources	Related to number of employees	Self-explanatory
Settlements	Activity analysis	Costs are directly assigned to Dx or Tx based on work program, able to specifically identify based on type of work
Customer Support Operations Applications	Related to Inergi CSO CCF&S	System support costs related to CSO are allocated based on CSO Inergi cost distribution (second tier)
Finance Applications	Related to Inergi Finance CCF&S	System support costs related to Inergi Finance are allocated based on Inergi Finance cost distribution (second tier)

CCF&S	Selection of Cost Driver	Approach Used for Selection of Cost Driver
Human Resources Applications	Related to Inergi HR CCF&S	System support costs related to Inergi HR are allocated based on Inergi HR cost distribution (second tier)
Passport Applications	Passport is related to Program Project Costs	Passport system is used to assign and control work program, therefore allocation related to current direct work program, not including CCF&S costs
Market Ready Applications	Planned costs to modify systems and business practices to meet several market opening requirements from Docket RP-2004-0017 / RP-2004-0118, Exhibit G-11, Tab 11, Schedule 1	Assessment of costs required to support ongoing operation of Open Market Systems (OMS).
Telecom Support	Physical units (a)	Physical count of # of telephones.
Infra-structure Svc. / Misc. Apps	Activity Analysis	Assessment of activities performed.
	Activity Analysis	Assessment of activities performed.
	Related to both non-energy revenue and assets	Related to both non-energy revenue and assets (50%/50%)

Ontario Energy Board (Board Staff) INTERROGATORY #92 List 1

Interrogatory

Ref: Exhibit C1 Tab 2 Schedule 6/ Issue 3.3
In this Exhibit, Hydro One discusses its shared services pricing and cost allocation methodology. Please provide an overview of the impact of this methodology in the following format for each of the 2006 historical, 2007 bridge and 2008 test years:

i) Amount of expenses paid to affiliates for services rendered and the percentage amount this represents of total expenses.
ii) Amount of revenue received from affiliates for services provided and the percentage amount this represents of total revenue.
iii) Amount of expenses incurred related to the provision of services to affiliates and the percentage amount this represents of total expenses.

Response

Please see responses in the table below for Hydro One Networks Inc. [(a)]:

	($ millions)	**2006**	**2007**	**2008**
(i)	Refer to Exh A Tab 8 Schedule 3			
	Expenses Paid to Affiliates:	6.4	8.7	9.0
	Total Expenses (OM&A and Capital)	1,573	1,942	2,200
	% of Total Expenses	0.4%	0.4%	0.4%
(ii)	Refer to Exh A Tab 8 Schedule 3			
	Revenue Received from Affiliates	4.5	3.8	4.0
	Total Revenue	4,151	4,138	4,197
	% of Total Expenses	0.1%	0.1%	0.1%
(iii)	Refer to Exh A Tab 8 Schedule 3			
	Expenses re: Provision of Services to Affiliates	4.5	3.8	4.0
	Total Expenses (OM&A and Capital)	1,573	1,942	2,200
	% of Total Expenses	0.3%	0.2%	0.2%

Note: Fees payable by affiliates to Networks for services provided are not recognized as revenue; they are netted against Networks OM&A.

(a) Includes Distributions and Transmission

Ontario Energy Board (Board Staff) INTERROGATORY #93 List 1

Interrogatory

Ref:Exhibit C2/Tab 4/Schedule 1/page1/ Issue 3.8
Hydro One has used a capital tax rate of 0.285%. The Ontario government has proposed to reduce this rate to 0.225% retroactive to January 1, 2007. It is likely that this rate will be substantively enacted sometime this spring.

a. Will Hydro One recalculate its 2008 draft rate order to reflect this tax change?
b. What will Hydro One do in its accounts to reflect the retroactive benefit of the lower capital taxes in 2007?

Response

a. Hydro One is not planning on updating its 2008 Distribution rate filing for changes in tax rates. If directed by the Board as part of the Rate Decision, Hydro One will incorporate any requested changes in tax rates in the final revenue requirement calculation and reflect this in the draft rate order.

b. The benefit of the lower capital tax rate in 2007 will be tracked in the tax deferral account for future disposition.

Ontario Energy Board (Board Staff) INTERROGATORY #94 List 1

Interrogatory

Ref: Exhibit C2/ Tab 6/ Schedule 1/Attachment A/ Issue 3.9

a. The tax rate for 2008 is now 33.5%. Will Hydro One recalculate its 2008 draft rate order to reflect this tax change?
b. Hydro One has provided tax information for 2004-2006 and for the test year 2008. The filing guidelines require a tax forecast to be provided for the 2007 bridge year as well.
c. Please provide the 2007 bridge year tax forecast in the format of that for 2008 found at Exhibit C2/ Tab 6/ Schedule 1/Attachment A/page1.

Response

a. Hydro One is not planning on updating its 2008 Distribution rate filing for changes in tax rates. If directed by the Board as part of the Rate Decision, Hydro One will incorporate any requested changes in tax rates in the final revenue requirement calculation and reflect this in the draft rate order.

b. See response below.

c. Hydro One provided tax information for 2004-2006 based on a Dx allocation of the tax returns already filed. The 2007 equivalent to Exhibit C2/ Tab 6/ Schedule 1/Attachment A/page1 will be submitted after the 2007 tax return is filed. It is anticipated that the 2007 tax return will be filed on or before June 30, 2008.

Ontario Energy Board (Board Staff) INTERROGATORY #95 List 1

Interrogatory

Ref: Exhibit C2/ Tab 6/ Schedule 1/Attachment B/ Issue 3.9

a. Please provide the Capital Cost Allowance (CCA) tax classes that Hydro One has used in the calculation of CCA for the smart metering activities. Please provide a schedule that shows the smart meter capital expenditures being added to rate base and how those costs map to the CCA tax classes for 2006, 2007 and 2008.

b. For accounting purposes, stranded conventional meters are being written off over four years within the depreciation charge or through a reallocation of accumulated depreciation. Please describe the tax treatment for stranded conventional meters that was used in 2006, 2007 and 2008.

Response

a. Hydro One places smart meters in Class 47, related computer system software in Class 12, and related computer hardware in Class 45. A schedule showing the UCC balances for smart meters is provided in the response to H-1-120a. Note that all smart meter in-service additions for the 2006 to 2008 period were assumed to be non-computer related expenditures.

b. The tax treatment for stranded conventional meters is as follows. The salvage value or proceeds of disposition, if any, for the meters coming out of service, will reduce the Undepreciated Capital Cost (UCC) of the class. Hydro One will continue to take capital cost allowance (CCA) on the remaining UCC that pertains to the meters that came out of service in the future years.

A detailed explanation follows.

For tax purposes, the Income Tax Act (ITA), paragraph 20(1)(a), allows a deduction in respect of the capital cost of a depreciable property. This deduction is referred to as CCA.

The dollar amount of the balance outstanding in each class, the "UCC" is increased when additional assets of the class are acquired and decreased when assets of the class are disposed of (subsection 13(21) of ITA). The UCC of the class is only decreased by the proceeds from the disposition of assets (to the extent of the capital cost of such assets) disposed of during the year, that fall within the class.

As stated above, the UCC of the class is reduced by proceeds of disposition up to the original cost of the asset. Hydro One will continue to claim CCA until there are no assets remaining in the class. A "terminal loss" can be claimed and will only arise when the taxpayer has disposed of all assets in the class. Where no other assets remain in the class, the terminal loss is equal to the UCC of the particular class.

The UCC is not reduced for assets coming out of service. It will only be reduced by any proceeds received should these assets be sold. Therefore, for the meters coming out of service, only the salvage value or proceeds will reduce the UCC of the class. Hydro One will continue to take CCA on the remaining UCC that pertains to the meters that came out of service in the future years.

Ontario Energy Board (Board Staff) INTERROGATORY #96 List 1

Interrogatory

Ref: Exhibit A/Tab 15/Schedule 3, Attachment A (Kinectrics study/July 27, 2007), Page viii, 2, 11/ Issue 1.6
The note below the table in Exhibit A/Tab 15/Schedule 3, Attachment A (Kinectrics study/July 27, 2007), Page viii, 2, 11, states that the new estimate of TLF includes a Supply Facilities Loss Factor (SFLF) of 1.0060 (i.e. 0.06%).

Please explain why the SFLF is significantly different from the industry norm of 1.0045.

Response

The Supply Facilities Loss Factor (SFLF) applicable to Networks' distribution system is estimated to be 1.0060 (i.e. 0.6%).

Hydro One filed evidence in support of the SFLF as part of Tab 2, Schedule 1 (Networks' Other Regulated Charges Retail Settlement Code Loss Factors) under proceeding RP-2000-0023/EB-2001-0233. That evidence noted that the value of 1.0045 pertains to all of Networks' transformation stations serving the province as a whole, whereas the value of 1.0060 relates to the transformation stations serving only Networks' Distribution system. The transformer stations serving only the Networks' Distribution system represent the smallest transmission connected transformers, which inherently have the highest losses of the Networks transformer population. The OEB, in Appendix E of its final rate order under Proceeding RP-2000-0023/EB-2001-0016 issued August 30, 2002, approved the SFLF of 1.006 for Hydro One Networks. Hydro One Networks is proposing to maintain the SFLF of 1.006, since there have been no substantive changes to the transformer population serving the Networks Distribution system.

Ontario Energy Board (Board Staff) INTERROGATORY #97 List 1

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 3, p. 2/ Issue 1.6
Consistent with the directive referred to in Exhibit A/Tab 15/Schedule 3/page 2, please confirm if a budget and work plan for all cost-effective line-loss reduction suggestions contained within the Kinectrics study have been included in the application.

Response

Hydro One has addressed all cost-effective line-loss reduction suggestions recommended by the Kinectrics' update study report.

Hydro One Networks initiated an $8 million distribution network loss reduction work program based on the Kinectrics 2005 study and fully addresses the cost effective initiatives contained in the 2007 update study. This work program is about 90% complete as of March 31, 2008.

As part of the follow up exercise to the Board's directive, Hydro One initiated a study (Ref. Exhibit A-15-3, Attachment A), based on new load profile and system information, to update the 2005 Kinectrics Report (ref. Exhibit A-15-3, Attachment A, Appendix A) that was filed with the board. The 2007 update study demonstrates that the additional $4.75M in spending identified in the 2005 study is not economically justified. The work undertaken as part of the $8M loss reduction program is described below.

Kinectrics Recommendation 10.1 Power Factor Correction and 10.2 Phase Balancing

The loss reduction work program is targeted to realize maximum benefit. In total 574 feeders were examined in the study phase. In all, 304 feeders had work specified to a varying extent. Some were phase balanced only, some had only capacitors specified, and many had both elements. The total anticipated capacity savings on project completion is in the order of 5.2 MW on peak. This represents an energy saving of about 15,000 MWH per year.

Kinectrics Recommendation 10.3 Conductor Change Out
"It is recommended that Hydro One conduct a detailed study of its circuits loaded greater than 95% to determine the most cost effective means of lowering losses."

Conductor change out is a capital intensive initiative that is managed through Hydro One's ongoing planning processes. These processes include; area supply, new customer impact, and feeder studies. The studies consider supply capability, power quality and losses reduction opportunities.

Hydro One monitors feeders on an ongoing basis. Feeder voltage and current readings are taken annually and feeders that are nearing the maximum load or require a review of protections are studied more closely. During this process, feeders approaching 95% of the rated capacity are identified and solutions developed. Only economic solutions are recommended and implemented. In a number of these cases the economic solution involves replacement of conductors to a larger size.

Hydro One has had many development projects involving conductor replacement based on end-of-life, or system needs, and loss reduction is included in the decision process.

Kinectrics Recommendation 10.4 Transformer Sizing and Efficiency

"It is recommended that Hydro One conduct an internal study of the cost of changing to more efficient transformers and compare the costs with the benefits presented."

As part of the tendering process, Hydro One Networks reviews and updates its distribution transformer cost-of-losses purchasing formula for evaluating distribution transformer purchases at Hydro One. A more efficient, higher cost transformer can be justified if it results in an off-setting reduction in the lifetime cost of losses. Hydro one is in the middle of a tendering process for distribution transformer that is driven by a new losses formula. Based on the results of the tendering process the most cost effective transformers will be selected.

In addition, Hydro One is investigating the effectiveness of newer technology "high amorphous steel core" transformers. If the evaluation proves positive, Hydro One will introduce these into the purchasing practices.

The Hydro One's distribution network loss reduction work program has been substantially completed as part of Hydro One's Conservation and Demand Management (C&DM) program. No new specific loss reduction initiatives are planned for 2008 and 2009. Going forward, line-loss reduction opportunities are captured in the core work programs under the proposed Capital and OM&A budgets included in this application. Any new specific loss reduction initiatives would be supported through new C&DM funding.

The management of electrical losses is integral part of Hydro One ongoing system analysis and investment decisions. Hydro One continues to consider loss reduction opportunities in all relevant investment decisions. Specifically;

- Standards development:
  - Standardizing on efficient equipment and materials considering life cycle costs
  - Adopting high efficiency equipment into standards

- Capital Projects:
  - Design and develop efficient systems
  - Consider losses in financial evaluations
  - Use of high efficient equipment where practical and economic

- Ongoing monitoring of the system
  - Ongoing analysis of the system to monitor performance and losses
  - Proactive phase balancing

Ontario Energy Board (Board Staff) INTERROGATORY #98 List 1

Interrogatory

Ref: Exhibit G2, Tab 5, Schedule 2, Page 18; Exhibit G2, Tab 5, Schedule 1, Page 16/ Issue 1.6
Loss factors by customer class effective May 1, 2007 and May 1, 2008 for core retail customers of Hydro One are provided in Exhibit G2/Tab 5/ Schedule 2/page 18 and Exhibit G2/Tab 5/Schedule 1/page 16.

a. Please confirm whether the "Factor" represents TLF.
b. Please explain the reason for the changes in the factors for certain customer classes between 2007 and 2008.

Response

a. Hydro One confirms that "Factor" represents TLF.

b. The reason for the change in TLF is explained in Exhibit G1, Tab 10, Schedule 1, page 2, line 16 to page 3, line 8.

For the Urban Residential and R1 Residential customer classes that will now include Acquired Residential customer classes, the proposed TLF is the weighted average TLF of Legacy and Acquired customers in each of the two classes. For General Service energy billed customers the proposed TLF is the approved TLF for Legacy Urban General Service and General Service single phase customers. For General Service demand billed customers, the proposed TLF is the approved TLF for Legacy three-phase General Service customers.

Ontario Energy Board (Board Staff) INTERROGATORY #99 List 1

Interrogatory

Ref: Exhibit G2, Tab 6 to Tab 93/ Issue 1.6
Loss factors effective May 1, 2007 and May 1, 2008 for 88 acquired utilities are provided in Exhibit G2/Tab 6 to Tab 93. For the 2007 results, loss factors are provided in conventional format, i.e. SFLF along with each of DLF and TLF for customers less than 5,000 kW and customers greater than or equal to 5,000 kW. For the 2008 results, loss factors are provided by customer class without distinction for the 5,000 kW threshold and clarification regarding DLF or TLF.

a. Please explain the reason for not providing these loss factors in the conventional format.
b. Please provide these loss factors in the conventional format.

Response

a. The reason is simplifying the information included in the Rates Schedules. All customers in Acquired LDCs below 5,000 kW are being charged TLF. None is charged just DLF.

   All Acquired customers above 5,000 kW are proposed to be in the Sub-Transmission class and are not included in the Rate Schedules for Acquired LDCs in Exhibits G2, Tab 6 to Tab 93.

b. Acquired Residential customers moved to Urban Residential class

Supply Facility Loss Factor	1.006
Distribution Loss Factor	1.072
Total Loss Factor	1.078

Acquired Residential customers moved to R1 Residential class

Supply Facility Loss Factor	1.006
Distribution Loss Factor	1.079
Total Loss Factor	1.085

Acquired General Service customers moved to Urban General Service energy billed or General Service energy billed

Supply Facility Loss Factor	1.006
Distribution Loss Factor	1.085
Total Loss Factor	1.092

Acquired General Service customers moved to Urban General Service demand billed or General Service demand billed

Supply Facility Loss Factor	1.006
Distribution Loss Factor	1.055
Total Loss Factor	1.061

Ontario Energy Board (Board Staff) INTERROGATORY #100 List 1

Interrogatory

Ref: Exhibit G1, Tab 10, Schedule 1. p.3 to 5/ Issue 1.6
A table of proposed TLFs for new customer classes is presented in Exhibit G1/Tab 10/Schedule 1/page 3 to page 5.

a. Please confirm that the Total Loss Factors in the table on page 3 are inclusive of the Supply Facility Loss Factor that usually has the value 1.0045.
b. Please provide a brief description of situations where the Total Loss Factor of 0.6% would apply to an express feeder (second paragraph on page 4), distinct from situations where the loss factor of the transformer at the station would apply (second paragraph on page 5).
c. Please provide a description of the range of Total Loss Factors that are applied by Hydro One based on engineering studies as described in the final paragraphs of page 4 and page 5.

Response

a. The Total Loss Factor in the table on page 3 includes the Supply Facility Loss Factor of 1.006 approved for Hydro One Legacy customers under Proceeding RP-2000-0023/EB-2001-0016 issued August 30, 2002.

b. The total loss factor of 0.6% would apply to the meter readings of an express feeder if the meter is located inside the station or within 1 pole outside of the station. If the meter is located at more than 1 pole away from the station, the total loss factors would be based on engineering studies. These engineering studies and the resulting factors take into account a combination of the applicable share of the specific transformation loss of the station as well as the radial line loss reflecting the distance between the station fence and the actual meter location. These factors are then used as inputs in an equation to calculate the losses. Please see the answer to section c) below.

c. Losses based on engineering studies are not applied by applying a calculated loss factor. Instead, losses each hour are calculated by equations, as per the IESO Metering Manual. Therefore, there is not a range of applied Total Loss Factors where losses are calculated based on engineering studies.

Ontario Energy Board (Board Staff) INTERROGATORY #101 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ pages 1 and 12/ Issue 1.5
In Schedule 3, page 1, the Applicant explains that as a result of the weather normalization of its historical loads, the forecast assumes typical weather conditions based on the average of the last 31 years. In Schedule 3, page 12, the Applicant explains that its weather correction methodology uses 4 years of daily load and weather data to establish certain relationships.

a. Please clarify and clearly differentiate between the respective uses of the 31-year-based and 4-year-based correction techniques,
b. Please clarify if the 4-year-based correction is identical (apart from the number of years) to the 5-year-based correction referenced in the Board's decision of the Applicant previous distribution rate case (RP-2005- 0020/EB-2005-0378, Decision with Reasons, April 12, 2006, page 5),
c. Please clarify the degree to which the Applicant believes it has taken account of possible climate changes through the correction techniques, and
d. Please identify any observed differences between the Applicant's weather normalization methodology/techniques and the IESO's weather normalization methodology/techniques.

Response

a. Hydro One Distribution uses 4 years of daily load and weather data to estimate an up-to-date statistical relationship between load and weather conditions. Hydro One Distribution uses the average of most recent 31 years of historical weather data to estimate the normal weather conditions and to calculate the weather correction amount. Detailed weather normalization steps using both techniques are described in detail in Appendix 4 of Exhibit A, Tab 14, Schedule 3 (pages 30-32).

b. The referenced 2 concepts are different. The 4 years of load and weather data are used to estimate the relationship between load and weather conditions. The 5 years of weather data referenced in page 5 of the previous Board decision (RP-2005-0020/EB-2005-0378, Decision with Reasons April 12, 2006) pertains to using the average of 5 years of historical weather data to estimate the normal weather conditions and to calculate the weather correction amount instead of using 31 years.

c. Hydro One Distribution believes its weather normalization methodology is appropriate. Using the latest 4 years of load and weather data allows the analysis to reflect the most recent load mix and weather conditions. Using long term (such as the average of most recent 31 years) weather conditions to estimate the normal weather

conditions is appropriate because short term (such as the average of the most recent 5 years) weather conditions are too volatile and as such would not correctly represent the normal weather conditions.

d. The IESO does not perform weather correction for distribution load. However, in terms of the weather correction methodology, the methods used by IESO and Hydro One are essentially similar in that they are based on establishing a relationship between load and weather conditions and then using that relationship in conjunction with 31 years of weather data (including temperature, wind speed, humidity and cloud cover) to calculate the weather correction amount. Observed differences are presented below.

- IESO averages the weather conditions first and then inputs the result in the relationship between energy and weather to calculate the normal load. In contrast, Hydro One inputs 31 years of weather data, one at a time (as alternative weather scenarios) in the relationship between load and weather and then averages the corresponding loads to calculate the weather-normal load. For each historical year, Hydro One also uses weather data with up to 1 week lag and 1 week lead to generate alternative weather scenarios and uses them in the calculation of the normal load. IESO does not use lags and leads.

- To calculate the weather-normal peak forecast, IESO allocates the normal extreme temperature in each month or season to Wednesdays only. This is done for reliability reasons so that IESO would be prepared to handle extreme peak if it happens during a weekday. Hydro One allocates weather conditions (extreme or not) according to their natural occurrence (including weekdays and weekends) as an appropriate measure for calculating monthly peak revenue.

Ontario Energy Board (Board Staff) INTERROGATORY #102 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ page 2/ Issue 1.5
In Schedule 3, page 2, the Applicant states, "The methodology described in this exhibit is similar to Hydro One's 2006 Distribution Rate case (RP-2005-0020/EB- 2005-0378)."

a. Please explain any changes in the methodology used in the current application that have resulted from the Applicant's Board-ordered review of the methodology it uses for its transmission-related cases (EB-2006-0501, Decision with Reasons, August 16, 2007, page 88).
b. Please explain any other changes (in addition to those identified in response (a.)) to the methodology that has been adopted since the 2006 distribution case, provide the reason(s) for these changes, describe the testing done and the results achieved that showed the changes improved the expected accuracy of the resulting forecast.
c. Describe any planned or likely changes to further improve the methodology,
d. Verify that in Table 1, the mean (1997-2006) "Variance for Plan Year" and "Variance for 2nd Year" values are in the order of -0.26% and -0.50% respectively,
e. Describe any plans the Applicant has to compensate for the methodology's bias to underestimate the Bridge Year forecast by about one-quarter of one percent and the Test Year forecast by about one half of one percent, and
f. Estimate the dollar effect on revenue at the proposed rates, if the actual to be 0.5% higher than forecast.

Response

a. The only change was the CDM forecast. Hydro One followed the Board's decision (in EB-2006-0501) and reduced the Ontario peak load by 1,000 MW in 2007. The CDM impact on Hydro One Distribution in 2007 reflects this adjustment. For 2008, Hydro One used the CDM forecast from the OPA consistent with the IPSP that was filed with the Board on August 29, 2007. Hydro One Distribution did review its weather normalization methodology and found that no change was required.

b. One minor change was made in updating the econometric equation with respect to the use of dummy variables in the model. Four dummy variables were deleted from the monthly econometric model as more information became available.
The 4 deleted dummy variables are described below:

DSUM = dummy variable to distinguish between summer and other months,
D0803 = dummy variable for the August 2003 Blackout, equals 1 in that month and zero elsewhere,
D97 = dummy variables to account for shift in load pattern in 1997, equals 1 since January 1997, zero elsewhere.

D02 = dummy variable to account for Market Opening in May 2002, equals 1 since May 2002, and zero elsewhere.

One dummy variable related to the 1998 Ice Storm is kept in the monthly econometric equation. The deletion of 4 dummy variables does not affect the forecast or the forecast accuracy but marginally affects the t-ratios of the estimated model coefficients.

c. Proposed plans for future research in load forecasting methodology include the following:
- Increase tracking and monitoring of CDM impacts on the distribution load;
- Update equipment use information on a regular basis;
- Assess customer behavioral changes with respective to energy use;
- Assess the impact of TOU rates on hourly load profiles; and
- Monitor industry trends and other LDC practices for consideration of methodology improvement.

d. The calculated mean "Variance for Plan Year" and "Variance for 2nd Year" values in Table 1 for the 1997-2006 period are -0.26% and -0.50% respectively.

e. The "bias" mentioned in (d) above is not statistically significant as it is within one standard deviation of the forecast. Since Hydro One Distribution experienced unusual events (such as Ice Storm in 1998, acquisition of almost 90 LDCs in 2001-2002 period, Sept 11 event in 2001) which affected the accuracy of the forecast performance, it will be more appropriate to focus the forecast performance achieved in more recent years (such as 2002-2006). The mean "Variance for Plan Year" and "Variance for 2nd year" values in Table 1 over the 2002 -2006 period show that the forecast performed very well. Consequently, there is no need to make any bias correction.

f. The dollar effect on revenue at the proposed rates is approximately $3 million if the actual load were to be 0.5% higher than forecast.

Ontario Energy Board (Board Staff) INTERROGATORY #103 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ page 3/ Issue 1.5
In Schedule 3, page 3, the Applicant explains that the methodology comprises a combination of elements that includes "mechanical adjustments to models commonly used in the forecasting business to include changes in …"

a. Please list, and describe as necessary, the elements to which mechanical adjustments may be applied,
b. Please describe fully what is meant by "mechanical" adjustments; specifically, are these automated adjustments that the computer model will make using pre-defined decision rules and requiring no human intervention or are they adjustments sometimes referred to as "manual" adjustments that are implemented by the forecaster on an ad hoc basis?
c. Please provide, in either case, the criteria used to make these mechanical adjustments and provide any other information necessary to fully explain this matter.

Response

a. The elements to which "mechanical adjustment" may be applied include:
   - Assessing the functional form of the equations and to make changes if required when new data becomes available; and
   - Updating the model coefficients as a result of incorporating new data.

b. "Mechanical adjustments" mean adjustments that are made to the models based on standard regression criteria to take into account the latest data as they become available. There are no manual adjustments.

c. Standard regression criteria are used to assess and make changes to the equations if required and update the model coefficients as new data becomes available. The criteria include the following:
   - R-square and Adjusted R-square as measures of goodness of fit;
   - T-ratios for estimated parameters to judge their statistical significance;
   - Durbin-Watson-Statistics as a test for detecting the presence of first order autoregressive errors; and
   - Residual analysis to make sure that it is identically and independently distributed.

Ontario Energy Board (Board Staff) INTERROGATORY #104 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ page 5 to 7/ Issue 1.4
In Schedule 3, page 5, Hydro One states, "The load forecast in support of this application was prepared and released in April 2007 using economic information and forecasts that were available in early 2007." Board staff understands that some of the key inputs to the forecast are those outlined in pages 6 and 7; specifically:

Item	2007 Growth	2008 Growth
Provincial GDP Forecast	1.7%	2.9%
Provincial Population Forecast	1.2%	1.2%
Provincial Housing Forecast	67,000 units	68,000 units
Commercial Output Forecast	2.3%	2.9%
Industrial Production Forecast	0.4%	3.0%

a. Please confirm that Board staff have correctly summarized the items listed (including that 2007 manufacturing sector growth has been considered synonymous/representative of 2007 industrial production growth),
b. Please list the actual 2007 growth rates for each of the five forecast items quoting the source(s) of the data and, where the complete year's data is not yet available, the most up-to-date data and the corresponding date(s) of issue,
c. Please list the currently-available 2008 growth forecasts for each of the five forecast items utilizing the same sources as used for the filed application, and
d. Please calculate the 2008 kWh forecast (before deducting for the impact of CDM) that would result from using the 2007 actual growth rates in b) and the updated forecast values in c) above.

Response

a. All numbers are correct, except industrial production should be -0.4% (i.e. decline by 0.4%) instead of 0.4%.

b. The estimates for 2007 values are presented below (Actuals for 2007 are not yet available).

Item	2007 Growth
Provincial GDP Forecast	2.0%
Provincial Population Forecast	0.8%
Provincial Housing Forecast	68,000
Commercial Output Forecast	3.7%
Industrial Production Forecast	-3.6%

c. The estimates for 2008 values (as of March 1, 2008) are presented below:

Item	2008 Growth
Provincial GDP Forecast	1.3%
Provincial Population Forecast	1.1%
Provincial Housing Forecast	64,000
Commercial Output Forecast	1.8%
Industrial Production Forecast	-0.8%

d. Using the estimates in (b) and (c), the 2008 kWh forecast (before deducting for the impact of CDM) is estimated to be about 41,210 GWh. Compared to 41,436 GWh as filed, this represents a decrease of 226 GWh.

Ontario Energy Board (Board Staff) INTERROGATORY #105 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ page 8/ Table 2/ Issue 1.5
In Schedule 3, page 8, Table 2, the Hydro One shows the load impact of CDM; specifically, for 2007 and 2008 the total impact is shown as 554 GWh and 770 GWh respectively. Hydro One noted that the CDM impact is the same as the 2007 CDM impact approved by the Board for Hydro One's Transmission Rate case (EB-2006-0501) issued on August 16, 2007. Board Staff note that the respective values quoted in the original August 15, 2007 filing of the current application were 747 GWh and 1,009 GWh.

a. Please list the programs that saw a change in the anticipated 2007 and 2008 CDM impacts from when the original August 15, 2007 estimates were filed until the December 18, 2007 estimates were filed, the magnitude of the changes and the rationale for the changes, and
b. Please clarify for each of the values shown in Table 2, the CDM impact as a result of Hydro One Distribution's own programs as distinct from programs implemented by other agencies such as federal and provincial governments, OPA and IESO.

Response

a. The information filed with the Board on August 15, 2007 did not reflect the Board's Decision in EB-2006-0501, since it was released subsequent to the original filing. The evidence filed on December 18, 2007 was updated to reflect the Board's Decision to reduce the Ontario peak load to 1,000 MW in 2007 and as a result, the CDM impact on Hydro One Distribution in 2007 was reduced from 747 GWh to 554 GWh. For 2008, Hydro One used the CDM forecast provided by OPA consistent with IPSP as filed on August 29, 2007 and as a result, the CDM impact on Hydro One Distribution was reduced from 1009 GWh to 747 GWh. Therefore, there are no specific program changes.

b. There was a typo in Table 2 (233 GWh in 2008 for embedded direct and LDC customers should be 333 GWh instead. The same typo also showed up in Table 4 of Exhibit A, Tab 14, Schedule 3, 233 GWh in that table should read as 333 GWh). The correct numbers in Table 2 in Exhibit A, Tab 14, Schedule 3 are presented below.

Table 2

CDM Impact on Hydro One Distribution Load
(GWh)

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
2006	194	151	345
2007	311	242	554
2008	437	333	770

Source: Exhibit A, Tab 14, Schedule 3, Page 6, Table 2

The CDM forecast for Hydro One retail customer in Table 2 include impacts from the following sources:

(1) CDM impact resulted from programs initiated by Hydro One Distribution;
(2) CDM impact resulted from programs initiated by other government agencies such as the federal and provincial governments, the OPA and the IESO;
(3) CDM impact resulted form Hydro One retail customers that are not captured and reported under (1) and (2)

Similarly, the CDM forecast for Embedded Direct and LDC customers includes the impacts from programs initiated by these customers (and in the LDC case, their own retail customers) as well as programs initiated by other government agencies.

Attached as Attachment A is a report entitled "Net Load Impact Analysis of Conservation and Demand Management" that shows the estimated CDM program results for each of the above components in detail using the best information currently available.

Table 1 (shown below) in Attachment A summarizes the CDM impact on Hydro One retail load since 2005. Compared to the CDM impact forecast used in Table 2 (shown above) in Exhibit A, Tab 14, Schedule 3, the net load impact analysis in Attachment A shows that the CDM forecast for Hydro One retail customers is appropriate. Based on available data to date, CDM program results exceeded the CDM forecast in 2006 and 2007 using conservative assumptions for natural conservation and will likely exceed the CDM forecast in 2008.

Table 1: CDM Impact Analysis on Hydro One Retail Load (GWh)

	Organization				*Total*	
Year	**Hydro One Programs**	**OPA Programs**	**Federal and Provincial Government Programs**	**Customer Conservation Actions**	**Annual Energy Savings**	**Cumulative Energy Savings**
2005	8	n/a	n/a	n/a	8	8
2006	91	4	44	99	238	246
2007	75	88	n/a	n/a	163	409
Total	174	92	44	99	409	

Note: N/A denotes CDM results are not available. Savings attributed to customer conservation actions are based on a conservative assumption for natural conservation as discussed in Appendix G.

Source: Attachment A to Exhibit H, Tab 1, Schedule 105, Table 1

As explained in Attachment A, Hydro One Distribution undertook a special study to estimate the net load impact of conservation actions initiated by our customers on their own. This impact would be in addition to the natural conservation that would be estimated by Hydro One Distribution's forecast equations. The results of the special study using conservative assumptions for natural conservation show that at least 99 GWh of savings in 2006 are attributed to the conservation actions from our retail customers. A special CDM survey was also conducted by Hydro One Distribution to assess what conservations our customers have undertaken since 2004. Results from 1,741 customers who responded to the survey confirm that Hydro One Distribution retail customers have responded to the conservation challenge, have participated in CDM programs offered by Hydro One Distribution, the OPA and other government agencies and have taken various conservation actions on their own to save electricity.

Table 2: CDM Impact Analysis for Embedded LDC Customers (GWh)

	Organization				Total	
Year	**LDC Programs**	**OPA Programs**	**Government Programs**	**Customer Conservation Actions**	**Annual Energy Savings**	**Cumulative Energy Savings**
2005	16	n/a	n/a	n/a	16	16
2006	16	1.5	26.5	60	104	120
Total	32	1.5	26.5	60	120	

Note: N/A denotes CDM results are not available. 2007 data are not yet available. Savings attributed to customer conservation actions are based on a conservative assumption for natural conservation assumption as discussed in Appendix J.

Source: Attachment A to Exhibit H, Tab 1, Schedule 105, Table 2

Table 2 summarizes the CDM impact analysis for the embedded LDC load for 2005 and 2006. Results for 2007 are not yet available for analysis. Due to the lack of information, similar analysis is not available for the embedded direct customers for 2005 and 2006. In 2007, program results from Hydro One Distribution's Double Returns Program for embedded direct customers are estimated to be about 23 MW for the winter months and 19 MW for the summer months. Based on the forecast

accuracy achieved for 2007 as presented in Table 3, it is reasonable to assume that the embedded direct and LDC customers are undertaking conservation actions and achieving similar CDM results in 2007 as Hydro One Distribution retail customers.

Table 3: Hydro One Distribution Forecast Accuracy for 2007

	Energy Purchases		
	Forecast (GWh)	Actual (GWh)	Difference (%)
Retail Customers	22,944	22,966	0.09%
Embedded LDCs & Directs	17,548	17,562	0.08%
Total	40,493	40,529	0.09%

Note: All figures are weather-normal

Source: Attachment A to Exhibit H, Tab 1, Schedule 105, Table 3

Net Load Impact Analysis of Conservation and Demand Management

March, 2008

1.0 Overview

This report presents a bottom-up analysis of Conservation and Demand Management (CDM) impact using information as of March 2008. The net load impact analysis was prepared by the load forecasting staff to help assess the CDM impact on Hydro One Distribution load.

The CDM impact on Hydro One Distribution load can be grouped in the following categories:

- CDM impact resulted from programs initiated by Hydro One Distribution;
- CDM impact resulted from programs initiated by other agencies such as the OPA, federal and provincial governments;
- CDM impact resulted from conservation actions initiated by Hydro One Distribution's retail customers on their own;
- CDM impact resulted from Hydro One Distribution's embedded direct and LDC customers.

Table 1: CDM Impact Analysis on Hydro One Retail Load (GWh)

	Organization				*Total*	
Year	**Hydro One Programs**	**OPA Programs**	**Federal and Provincial Government Programs**	**Customer Conservation Actions**	**Annual Energy Savings**	**Cumulative Energy Savings**
2005	8	n/a	n/a	n/a	8	8
2006	91	4	44	99	238	246
2007	75	88	n/a	n/a	163	409
Total	174	92	44	99	409	

Note: N/A denotes CDM results are not available. Savings attributed to customer conservation actions are based on a conservative assumption for natural conservation as discussed in Appendix G.

Table 1 summarizes the CDM impact on Hydro One retail load since 2005. Compared to the CDM impact forecast used in EB-2007-0682 (see Appendix A for details), the net load impact analysis in this report shows that the CDM forecast for Hydro One retail customers is appropriate. Based on available data to date, CDM program results exceeded the CDM forecast in 2006 and 2007 using conservative assumption for natural conservation and will likely exceed the CDM forecast in 2008.

Table 2: CDM Impact Analysis for Embedded LDC Customers (GWh)

	Organization				Total	
Year	**LDC Programs**	**OPA Programs**	**Government Programs**	**Customer Conservation Actions**	**Annual Energy Savings**	**Cumulative Energy Savings**
2005	16	n/a	n/a	n/a	16	16
2006	16	1.5	26.5	60	104	120
Total	32	1.5	26.5	60	120	

Note: N/A denotes CDM results are not available. 2007 data are not yet available. Savings attributed to customer conservation actions are based on a conservative assumption for natural conservation assumption as discussed in Appendix J.

Table 2 summarizes the CDM impact analysis for the embedded LDC load for 2005 and 2006 (see Appendix J for details). Results for 2007 are not yet available for analysis. Due to the lack of information, similar analysis is not available for the embedded direct customers for 2005 and 2006. In 2007, program results from Hydro One Distribution's Double Returns Program for embedded direct customers are estimated to be about 23 MW for the winter months and 19 MW for the summer months. Based on the forecast accuracy achieved for 2007 as presented in Table 3, it is reasonable to assume that the embedded direct and LDC customers are undertaking conservation actions and achieving similar CDM results in 2007 as Hydro One Distribution retail customers.

The following sections provide a brief discussion of CDM program results achieved to date.

Table 3: Hydro One Distribution Forecast Accuracy for 2007

	Energy Purchases		
	Forecast (GWh)	Actual (GWh)	Difference (%)
Retail Customers	22,944	22,966	0.09%
Embedded LDCs & Directs	17,548	17,562	0.08%
Total	40,493	40,529	0.09%

Note: All figures are weather-normal

2.0 CDM Programs Initiated by Hydro One Distribution

In 2005, Hydro One Distribution received approval from the Board for the $39.5 million CDM Plan covering the 2005-2007 period. After the 3rd tranche funding, Hydro One Distribution intends to rely on the OPA managed funds from the Global Adjustment Mechanism for its CDM initiatives in 2008 and beyond.

The net load impact analysis of CDM programs initiated by Hydro One Distribution is summarized below in Table 4 (please refer to Appendix B for more details). These results are based on the annual CDM reports submitted by Hydro One Distribution to the Board. Since the 2008 CDM programs are not yet finalized, the information presented for 2008 in Appendix B is also preliminary.

Table 4: Net Load Impact of CDM Programs Initiated by Hydro One

Year	Annual Peak Savings (MW)	Annual Energy Savings (GWh)	Cumulative Energy Savings (GWh)
2005	0.6	8	8
2006	9.9	91	99
2007	53	75	174

3.0 CDM Programs Initiated by Other Agencies

In addition to CDM programs offered by Hydro One Distribution, there are many programs offered by other agencies such as the OPA and federal and provincial governments. The CDM programs initiated by these agencies will have an impact on Hydro One Distribution load. The following sections provide a brief discussion of these programs. More details are provided in Appendices C, D and E.

CDM Programs Initiated by OPA

The OPA is responsible for meeting the CDM targets set by the Ontario Government. Since 2006, the OPA has funded a number of conservation pilots and province-wide programs. The impact of the OPA programs on Hydro One Distribution retail customers is estimated to be about 4 GWh in 2006 and about 88 GWh in 2007. Details of the OPA program savings and the impact on Hydro One Distribution load are presented in Appendix C.

CDM Programs Initiated by Federal and Provincial Governments

Natural Resources Canada (NRCan) is the lead federal department delivering energy efficiency programs for the country. Aside from setting the overall energy policy, the department spends approximately $220M per year on energy efficiency programs of various types. The Government of Ontario also implements a number of CDM programs, such as in-house efficiency and CDM programs for the MUSH sector. In 2006, there were approximately 22 federal and provincial government-initiated CDM programs in Ontario, with an estimated impact of 85 MW and 392 GWh. The estimated impact of these programs on Hydro One Distribution retail customers is estimated to be about 44 GWh in 2006. Details of programs can be found in Appendix D.

CDM Programs Initiated by Other Agencies

Over the past few years, various associations and communities in Ontario have also offered pilot projects and educational information. Quantitative results of these CDM

activities are not readily available; however, it is reasonable to expect that there will be spill-over effects on Hydro One Distribution retail customers. A sample list of these programs is presented in Appendix E.

4.0 Conservation Actions Initiated by Customers

CDM programs initiated by Hydro One Distribution, OPA and other federal and provincial governments are mostly program-specific and as such the program results are tracked and measured. Conservation actions initiated by customers on their own are difficult to measure because there are no specific evaluations to capture these impacts. For example, it is very difficult to measure the "cultural change" associated with the CDM education and communication materials circulated by Hydro One Distribution to its retail customers (see Appendix F for details).

Hydro One Distribution undertook a special study to measure the net load impact of conservation actions initiated by our customers on their own. The results of the special study show at least 99 GWh of savings in 2006 can be attributed to the conservation actions from our retail customers (see Appendix G for details).

A special CDM survey was also launched by Hydro One Distribution to confirm what conservation actions our customers have undertaken since 2004. Of the 4,437 customers who received the e-mail survey, 1,741 customers (39.2%) responded. Detailed analysis of the survey results can be found in Appendix H. Based on the survey responses, it is clear that Hydro One Distribution retail customers have responded to the conservation challenge, have participated in CDM programs offered by Hydro One Distribution, the OPA and other government agencies and have taken various conservation actions on their own to save electricity.

Appendix A: Hydro One Distribution CDM Forecast

This appendix summarizes the CDM forecast prepared by Hydro One Distribution submitted to the Board in 2005 (EB-2005-0378) and in 2007 (EB-2007-0681).

Table A1: CDM Forecast (in GWh) Submitted in 2005 (EB-2005-0378)

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
2004	0	0	0
2005	49	39	88
2006	194	157	351

Note: Figures presented are cumulative CDM impact since 2004

The CDM forecast presented in Table A1 was prepared in April 2005 based on the assumption that 675 MW of the 1,350 MW peak load reduction target for 2007 would be achieved by 2006 and the rest would be achieved in 2007. Of the 675 MW to be achieved by 2006, 375 MW were assumed to be achieved through load management programs (and assumed to have no impact on energy) and 300 MW were assumed to be achieved through conservation programs. Of the 300 MW, 43.6 MW were prorated to Hydro One Distribution using Hydro One Distribution's share of the provincial peak in 2004. Using an average load factor of 62.5% for Hydro One Distribution's CDM initiatives, 194 GWh of energy impact were estimated. Similarly, 35.9 MW and 157 GWh were estimated for the embedded customers using their provincial share of electricity consumption and an average load factor of 50%.

Table A2: CDM Forecast (in GWh) Submitted in August 2007 (EB-2007-0681)

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
2006	194	151	345
2007	420	327	747
2008	568	441	1,009

Note: Figures presented are cumulative CDM impact since 2004

The CDM forecast presented in Table A2 was prepared in April 2007 using the same approach as in Table A1. For 2008, an additional 450 MW of CDM impact were assumed using a straight line allocation method for the additional peak load reduction target of 1,350 MW for 2010. At the time the forecast was prepared, OPA's IPSP CDM forecast was not yet available.

Table A3: CDM Forecast (in GWh) Submitted in December 2007 (EB-2007-0681)

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
2006	194	151	345
2007	311	242	554
2008	437	333	770

Note: (1) Figures presented are cumulative CDM impact since 2004
(2) 2007 numbers in Table A2 was porated by the ratio of 1000/1350
(3) OPA's IPSP CDM forecast of 251 MW and 0.8 TWh for 2008 were used

In September 2007, the CDM forecast was revised (see Table A3) incorporating the Board's decision in EB-2006-0501 to include 350 MW of natural conservation in the provincial CDM target for 2007. The CDM impact in 2008 for the province was provided by the OPA consistent with the IPSP CDM forecast filed to the Board on August 29, 2007. The same allocation method was used as in Table A1 and A2.

Appendix B: Summary of Program Results Initiated by Hydro One Distribution

This appendix summarizes the CDM program results for 2005, 2006 and 2007 for Hydro One Retail customers. Appendix Table B1 to B3 provide a "bottom up" view of Hydro One Distribution CDM impact (GWh and MW savings earned) between 2005 and 2007 by program and sector. At the time this report is prepared, 2008 CDM programs are not yet finalized. The information presented in Table B4 is based on best available information as of end of March, 2008.

Table B1: Program Results for 2005:

PROGRAM	3 YEAR BUDGET ($K)	SPENDING TO DEC 2005 ($K)	ANNUAL SAVINGS KW	ANNUAL SAVINGS kWh	LIFECYCLE SAVINGS kWh	LIFECYCLE $/kWh
Residential						
Smart Meters	7,800	519				
Real Time Monitoring Pilot	425	467	38	401,482	2,007,410	0.23
Real Time Monitoring Program	1,400					
Mass Market Coupon Initiative	1,500	277	285	7,261,874	70,142,678	0.004
LED	430	171		219,079	6,572,370	0.026
Low Income/Social Housing	5,000	46				
Load Control Pilot	1,220	783	358			
Load Control Program	3,500	0				
Energy Audits/Analysis	230	0				
Total	21,505	2,263	681	7,882,435	78,722,458	0.012
Commercial/Industrial, Farm, MUSH						
Interim Time of Use	475	238				
C/I MUSH Conservation	600	261				
C/I & Farm Load Control	3,500	0				
Farm Energy Efficiency	750	110				
Total	5,325	609	0	0	0	0
Common						
Distribution Loss Reduction	8,000	0				
Program Management and Research	3,700	804				
Communication and Education	1,000	305		286,578	1,146,312	0.266
Carrying Charge		25		n/a		
Total	12,700	1,134	0	286,578	1,146,312	0
Grand Total	39,530	4,006	681	8,169,013	79,868,770	0.021

Source: Hydro One Networks Inc. Conservation and Demand Management Plan Annual Report, Appendix C to December 31, 2005, 9RP-2004-0203\EB-2005-0198) filed March 31st, 2006.

Table B2: Program Results for 2006:

PROGRAM	3 YEAR BUDGET ($K)*	LTD SPENDING TO DEC 2006 ($K)	Cumulative SAVINGS KW**	Cumulative ANNUAL SAVINGS kWh**	Cumulative LIFECYCLE SAVINGS kWh
Residential					
Smart Meters	7,800	7,800	-	-	-
Real Time Monitoring Pilot	425	466	38	401,482	2,007,410
Real Time Monitoring Program	4,075	3,242	3,357	14,809,145	74,047,076
Mass Markets	1,870	1,382	4,671	81,724,679	526,034,109
LED	380	296	-	546,454	16,393,624
Low Income/Social Housing	4,400	497	6	294,078	5,263,750
Load Control Pilot	710	710	358	-	-
Load Control Program	3,500	2,117	2,169	806,435	8,780,648
Total	23,160	16,510	10,599	98,582,273	632,526,617
Commercial/Industrial, Farm, MUSH					
Interim Time of Use	920	632		-	-
C/I MUSH Conservation	600	240	21	185,396	1,870,103
C/I & Farm Load Control	3,500	2		-	-
Farm Energy Efficiency	750	114	9	64,000	408,009
Total	5,770	988	30	249,396	2,278,112
Common					
Distribution Loss Reduction	7,200	877		-	-
Program Management and Research	2,600	1,576			
Communication and Education	800	463	-	286,578	1,146,312
Carrying Charge		25		-	-
Total	10,600	2,941	-	286,578	1,146,312
Grand Total	39,530	20,438	10,629	99,118,247	635,951,041

*Note: The budget has been reallocated from approved plan and the reallocations are within the 20% flexibility allowed by the Board. The new allocation has already been provided to the Board in the 2006 Q4 report.
**Cumulative annual and lifecycle KW and KWh savings are reported as per calculations in Appendices B.

Source: Hydro One Networks Inc. Conservation and Demand Management Plan Annual Report, Appendix C to December 31, 2005, RP-2004-0203\EB-2005-0198 filed March 31st, 2007. Annual energy savings for 2006 are approximately 91 GWh.

Table B3: Program Results for 2007

PROGRAM	3 YEAR BUDGET ($K)*	LTD SPENDING TO DEC 2007 ($K)	Cumulative SAVINGS KW**	Cumulative ANNUAL SAVINGS kWh**	Cumulative LIFECYCLE SAVINGS kWh
Residential					
Smart Meters	7,800	7,800	-	-	-
Real Time Monitoring Pilot	470	466	38	401,482	2,007,410
Real Time Monitoring Program	5,085	5,082	4,767	22,946,131	114,732,007
Mass Markets	2,465	2,465	5,854	98,915,451	635,802,470
LED	430	424	-	546,454	16,393,624
Low Income/Social Housing	3,200	3,163	879	8,373,080	115,751,166
Load Control Pilot	710	710	358		
Load Control Program	4,660	4,536	13,198	4,113,097	48,811,867
Energy Audit Analysis	215	213	-	-	-
Total	25,035	24,859	25,094	135,295,696	933,498,544
Commercial/Industrial, Farm, MUSH					
Interim Time of Use	1,130	997	-	-	-
C/I MUSH Conservation	1,040	948	2,011	14,503,166	210,511,025
C/I & Load Control	2,390	2,339	33,773	108,854,220	108,898,068
Farm Energy Efficiency & Farm Load control	510	458	349	1,970,695	17,454,329
Total	5,070	4,742	36,132	125,328,081	336,863,422
Common					
Distribution Loss Reduction	6,175	5,399	2,362	7,207,655	144,153,108
Program Management and Research	2,500	2,425	43	396,185	3,248,037
Communication and Education	765	744	140	3,649,933	30,145,133
Carrying Charge		25		-	-
Total	9,440	8,593	2,545	11,253,773	177,546,278
Grand Total	39,545	38,194	63,771	271,877,550	1,447,908,244

Note: *The budget has been reallocated from approved plan and the reallocations are within the 20% flexibility allowed by the Board.
** Cumulative annual and lifecycle KW and KWh savings are reported as per calculations in 2007 CDM Annual Report, Appendices B.

Source: Hydro One Networks Inc. Conservation and Demand Management Plan Annual Report, Appendix C to December 31, 2005, RP-2004-0203\EB-2005-0198) filed March 31st, 2008.

Table B4: Program Expected to be in 2008 (Best Available Information Only)

Program	2008 Forecast			
	Budget	kW Savings	kWh Savings	Target Units
MARR Funded Programs				
Distribution Loss Reduction	$ 800,000			
Time of Use Pilot	$ 130,000			
C/I, Mush Conservation	$ 90,000			
C/I and Load Control	$ 50,000			
Program Management and Research	$ 80,000			
Low Income	$ 50,000			
Residential Load Control	$ 130,000			
Miscellaneous	$ 25,000			
Rate Funded Administration of CDM work				
Maintenance of MARR Funded Programs and Minimum Capability	$ 1,000,000			
OPA Core Programs				
Great Refrigerator Roundup	$ 650,000			20,300
Electricity Retrofit Incentive Program	$ 2,200,000			145
Peaksaver	$ 8,500,000			14,900
Summer Sweepstakes	Program details not yet available.			
Small Commercial Direct Install	Program details not yet available.			
OPA Custom Program Applications				
Double Return	Under development			
Arena Retrofit	Under development			
Compressed Air	Under development			
In Home Display	Under development			
First Nations Retrofit	Under development			
Low Income Retrofit	Under development			
Ministry of Energy Funding				
Powerhouse	$ 500,000			

Source: Hydro One Distribution and OPA

Appendix C: Summary of Program Results Initiated by OPA

This appendix summarizes the OPA program results for Hydro One Retail customers for 2006 and 2007. The five Ontario Power Authority-coordinated conservation programs delivered in 2006 resulted in annual savings of 378 million kilowatt-hours and a reduction in the summer peak demand of approximately 100 megawatts. Table C1 below presents the overall impacts of OPA-coordinated conservation programs in 2006. Hydro One Distribution Retail customers' savings from these programs have been estimated using a market share of about 20%. This percentage is based on the number of Hydro One Distribution customers relative to the entire province.

Table C1: OPA-Initiated Program Results in 2006

OPA Program	Total Annual GWh savings	Total Annual MW savings	GWh Savings for Hydro One Retail Customers	MW Savings for Hydro One Retail Customers
Every Kilowatt Counts	358.0	84.3	63.7 *	1.2
Cool Savings Rebate	10.4	10.7	2.1	2.2
Hot Savings Rebate	3.7	3.0	0.8	0.6
Secondary Refrigerator Retirement	5.6	2.6	1.1	0.5
Total	377.7	100.5	67.7	4.5

Source: OPA 2006 Conservation Bureau Annual Report. Please note that results from Every Kilowatt Counts have already been included in the LDC Annual CDM reports shown in Table B2. The additional energy contribution, not added elsewhere, is about 4 GWh and the peak contribution is about 3.3 MW.

In 2007, the OPA funded a number of conservation programs for the following sectors:

- Mass markets – Every Kilowatt Counts, peaksaver®, The Great Refrigerator Roundup
- Business markets – Electricity Retrofit Incentive Program, Building Owners and Managers Association Toronto program, City of Toronto programs
- Demand response suite of three programs

Although final results are not yet available, preliminary results indicate that OPA-coordinated conservation programs in 2007 resulted in an annual savings of approximately 88 GWh for Hydro One customers. Table C2 below summarizes the

energy and peak impacts of OPA-coordinated conservation programs in 2007 for Hydro One Distribution Retail customers.

Table C2: OPA-Initiated Program Results in 2007

OPA Program	GWh Savings for Hydro One Retail Customers	MW Savings for Hydro One Retail Customers
Peak Saver	0.604	5.55
Electricity Refrofit Incentive Program	0.013	0
Summer Savings Challenge	74.09	16.65
Great Refrigerator Round Up	13.646	3.25
Total	**88.35**	**25.45**

Source: Estimates prepared by Hydro One Distribution using best available information from OPA as of March, 2008. The peak savings for the Summer Savings Challenge were estimated using the load factor approach.

Appendix D: Summary of Program Results Initiated by Federal and Provincial Governments

This appendix summarizes the program results initiated by federal and provincial governments in 2006 and the estimated impacts for Hydro One Retail customers using Hydro One's share of provincial total.

Table D1: Program Results by Federal and Provincial Governments in 2006

Federal / Provincial	*Federal and Provincial Programs*	*Electricity Saved (kWh)*	*Peak Summer Electricity Saved (KW)*	*Hydro One Share (kWh)*	*Hydro One Share (kW)*
Federal	Commercial Building Incentive Program (CBIP)	1.4	0.2	0.1	0.0
Federal	Industrial building Incentive Program (IBIP)	16.6	4.2	1.7	0.4
Federal	Canadian Industry Program for Energy Conservation (CIPEC) - Industrial Energy Audit Incentive	90.4	13.9	9.0	1.4
Federal	Canadian Industry Program for Energy Conservation (CIPEC) - Dollars to Sence Training Workshop	132.3	20.4	13.2	2.0
Federal	R-2000 New Housing Certification Program	0.4	0.1	0.1	0.0
Federal	Energuide for New Homes	1.0	0.1	0.2	0.0
Federal	Energuide for Existing Homes	18.9	2.0	3.9	0.4
Federal	Energy Star Labelling Program	48.4	5.2	9.9	1.1
Provincial	Green Municipal Fund	51.2	12.8	3.8	1.0
Provincial	Building Retrofits and Upgrades : ORC Buildings	7.1	1.8	0.5	0.1
Provincial	Building Retrofits and Upgrades : Ministry Buildings	11.7	2.9	0.9	0.2
Provincial	Detention Centres	2.4	0.0	0.2	0.0
Provincial	Co-generation Sites for Provincial Buildings	5.4	0.6	0.4	0.0
Provincial	Cool Shops	2.6	1.8	0.2	0.1
Provincial	EcoSchools	0.5	0.1	0.0	0.0
Provincial	Reduce the Juice	1.4	0.2	0.1	0.0
Total		391.5	66.2	44.3	6.9

Source: "Overview and Analysis of Ontario Provincial and Federal Electricity Conservation and Efficiency Initiatives, Marbek Resource Consultants, July 2007

Appendix E: Other CDM Programs and Educational Initiatives in Ontario

This appendix presents a sample of other CDM programs and educational initiatives offered by other organisations which will have an impact for Hydro One Retail customers.

Table E1: Selected Other CDM / Educational Initiatives in Ontario

Program Name	Institution
Convenience store program	Ontario Convenience Stores Association
Compressed Air Leak Management System	Ontario Mining Association
Direct Install Small Business Pilot Project	Sustainable Buildings Canada
Direct Install Small Business Pilot Project	Greensaver
Energy Benchmarking Practices in the Ontario Wine Industry	Wine Council of Ontario
Energy Management for University Health Network hospitals	University Health Network
Energy Management Best Practices in Multi-Use Facilities	Ontario Energy Association
Energy Star for New Homes	EnerQuality Corporation
Forest Industries Energy Manager and CDM Pilot	Ontario Forest Industries Association
Agricultural Learning Locations	AgEnergy Cooperative Inc.
Conservation through Dialogue and Design	Association of Major Power Consumers in Ontario
Convenience Stores Conservation Pilot	Ontario Convenience Store Association
Effective Demand Side Management (DSM): Webinar Series	Canadian Energy Efficiency Alliance
Energy Efficiency Education Program for Trade Contractors Serving SME Sector	Energy Efficient Contractors Network
Energy Efficiency Secretariat for the College System	Association of Colleges of Applied Arts and Training of Ontario
Energy Savings & Capital Renewal Symposium	Association of Colleges of Applied Arts and Training of Ontario
ENERGY STAR® for New Homes	Enerquality
Feasibility of Expanding the Toronto Atmospheric Fund (TAF)	Clean Air Partnership
First Nations Conservation Project: Chippewas of Georgina Island	WindFall EcoWorks
Flick Off! / Unplug!: Text-Messaging Pilot	Summerhill Group
Greenlearning.ca	Pembina Institute
Market-Driven Incentives for the Residential Sector - Pilot Project	Green$aver
Net-Zero Energy homes - Building Capacity in Ontario	Net-Zero Energy Home Coalition
OFIA 2007 Energy Management Program	Ontario Forest Industries Association
OFIA Interim Energy Management Program	Ontario Forest Industries Association
On-farm Energy Audits	Ontario Ministry of Agriculture, Food and Rural Affairs

Pilot Energy Program (PEP) for Food Processors	Ontario Ministry of Agriculture, Food and Rural Affairs
Project Porchlight	One Change
Reduce the Juice	Power Up Renewable Energy
Restaurants and Green Grocers Energy Efficiency Pilot	Green$aver
Rogers Centre Charette	Sustainable Buildings Canada
Skills for Energy Efficient Construction	Clean Air Partnership
Virtual Power Plant: Exploring the Potential for Aggregated Cogeneration	Canadian Energy Efficiency Alliance

Source: Conservation Bureau Website, www.conservationbureau.on.ca

Appendix F: CDM Education and Communication Programs

This appendix briefly describes the CDM education and communication programs and activities offered by Hydro One Distribution and other government agencies. In the past few years, Hydro One Distribution has used bill inserts, newspapers, special events, conferences and workshops, radio and TV series, fact sheets, energy efficiency guides, brochures, on-line energy audits and direct mail to promote energy efficiency and conservation. The availability of this information will help our customers build the "conservation culture". Please visit www.PowerSaver.ca for more information.

Table F1 shows all energy conservation related bill inserts sent out to customers in 2005 by Hydro One.

Table F1: Distribution of Bill Inserts and Energy Saving Tips in 2005

Topic	Printed and distributed pieces (000s)
Home Energy Efficiency Grant	22
Switch to Cold – 1	1,215
Switch to Cold – 2	1,215
Lighten Your Electricity Bill	1,215
Total	**3,667**

Source: Hydro One Communications Department

In 2006, Hydro One distributed 18% more inserts and energy saving tips with customer's monthly bills. Table F2 below lists all the energy saving or conservation related inserts sent to customers.

Table F2: Distribution of Bill Inserts and Energy Saving Tips in 2006

Topic	Printed and distributed pieces (000s)
Staying Connected - Winter '05	1,215
Staying Connected - Spring '06	1,215
Staying Connected - Summer '06	1,215
Power Cost Monitors	140

Power Cost Monitors v2	140
Cold Shoulder Fridge Retirement	350
SmartStat P. Thermostats	25
Don't be a Fridge Magnet	22
LED Traffic Lights	1
LED Traffic Lights	1
LED Light Exchange	1
Total	**4,325**

Source: Hydro One Communications Department

In 2007 the number of energy saving bill inserts doubled in comparison to 2006. Table F3 provides details of inserts sent to customers in 2007.

Table F3: Distribution of Bill Inserts and Energy Saving Tips in 2007

Topic	Printed and distributed pieces (000s)
Staying Connected - Winter 06-07	1,215
Staying Connected - Summer '07	1,215
Staying Connected - Fall '07	1,215
Smartstat thermostat, Zones 1&2	150
Online Appliance Survey	100
Cold Shoulder Fridge Retirement	1,500
10/10 Summer Savings program	950
Peaksaver thermostat program	1,215
OPA Great Refrigerator Roundup	1,500
PowerSaverPlus for Residential & Business Customers	1,500
Electricity Retrofit Incentive Program – ERIP	15
ERIP	15
ERIP promotional card on heavy stock	11
Total	**10,609**

Source: Hydro One Communications Department

Other Sources

In addition to Hydro One Distribution CDM education and communication program and activities, similar CDM materials and communication programs are offered by other

government agencies that may have an impact on Hydro One Retail customers can be found on the following websites:

- OPA - http://www.powerauthority.on.ca
- Office of Energy Efficiency - http://oee.nrcan.gc.ca
- Ministry of Energy - http://www.energy.gov.on.ca
- Powerwise - http://www.powerwise.ca

Appendix G: Net Load Impact Analysis of Conservation Actions Initiated by Customers

Hydro One Distribution undertook a special analysis to measure the energy savings associated with conservation actions undertaken by its customers. This impact would be in addition to the natural conservation that would be estimated by Hydro One Distribution's forecast equations. Customer conservation actions could be attributed to a numbers of reasons, including the following:

1. Conservation programs initiated by Hydro One Distribution
2. Conservation programs initiated by other government agencies such as OPA, federal and provincial governments.
3. Conservation actions initiated by customers on their own that are not captured and reported in (1) and (2).

The methodology used by Hydro One Distribution for this analysis is summarized below:

1. Hydro One Distribution created a database for 2003-2006 for customers who had billing information (and associated meter readings) covering the entire period. New customers or customers cancelling their service during this period with Hydro One Distribution were excluded. As a result, a database of over 515,000 was created. 2007 data was not analyzed because final billing data for the calendar year is not yet available.
2. Only residential customers were analyzed. General Service customers were not analyzed because they are more prone to changing economic conditions and as such it would be difficult to differentiate between changes in electricity consumption due to conservation actions or economic activities.
3. Customer electricity consumption data were normalized to take out changes due to unusual weather effects. The weather normalization methodology used by Hydro One Distribution was approved by the Board in the Distribution Cost Allocation Review (EB-2005-0317) and Hydro One's 2006 Distribution Rate case (EB-200500378).

4. Any changes in electricity consumption should be net of natural conservation. Two scenarios were used in this analysis:
    a. Using Hydro One Distribution's estimate of natural conservation of 0.4% per year; and
    b. Using natural conservation of 1% for 2006. This estimate is considered high but Hydro One Distribution is using this estimate as sensitivity analysis.
5. All program savings should be considered in order to estimate the net savings attributed to conservation actions initiated by customers on their own.

Table G1 shows the weather-normalized consumption for over 515,000 residential with good monthly billing data for 2003-2006 by customer rate class. A decline of 2.8% in energy consumption was observed for the residential customers in 2006. The decline in electricity consumption, as explained before, can be attributed to a number of reasons, including the CDM program impacts initiated by Hydro One Distribution, OPA, other government agencies, customer conservation actions on their own as well as natural conservation.

Table G1: Residential and Farm Consumption 2003 - 2006

Customer Class	Customer Count	2003 GWh	2004 GWh	2005 GWh	2006 GWh
Residential – High Density	195,242	2,644	2,675	2,674	2,587
Residential – Low Density	187,201	2,910	2,959	2,923	2,848
Residential – Acquired	86,383	981	982	996	973,
Urban	46,673	502	507	522	508
Total	515,499	7,037	7,123	7,115	6,916
% change for all residential customers			**1.23%**	**-0.11%**	**-2.80%**

Note: All figures are weather-normal. Only customers with complete monthly billing data for all four years are used in the analysis.

Table G2 estimates the net savings attributed to customer conservation efforts in 2006 net of all program-driven CDM results and natural conservation (using 1%). Table G3 does the same analysis using natural conservation of 0.4%. Based on this analysis, net savings of conservation efforts form Hydro One Distribution Retail customer are estimated to range from 109 GWh to 168 GWh in 2006.

Table G2: Net Customer Conservation Savings Using 1% Natural Conservation

Description	Percentage	Energy (GWh)
Total Energy Consumption (Residential and Farm) in 2006		11,543
Change in Energy Consumption in 2006 over 2005	-2.80%	323
Less Natural Efficiency Assumption of 1.0%	-1.00%	115
Less Impacts from Hydro One Distribution and other programs		109
CDM impact attributed to customers' own conservation actions		**99**

Note: 11,543 GWh are weather-normal residential energy load in 2006 for Hydro One Distribution Retail customers. The 109 GWh are based on residential programs analysis in this report.

Table G3: Net Customer Conservation Savings Using 0.4% Natural Conservation

Description	Percentage	Energy (GWh)
Total Energy Consumption (Res and Farm customers) in 2006		11,543
Change in Energy Consumption in 2006 over 2005	-2.80%	323
Less Natural Efficiency Assumption of 0.4%	-0.4%	46
Less Impacts from Hydro One Distribution and other programs		109
CDM impact attributed to customers' own conservation actions		**168**

Note: 11,543 GWh are weather-normal residential energy load in 2006 for Hydro One Distribution Retail customers. The 109 GWh are based on residential programs analysis in this report.

Appendix H: Summary Results of Hydro One 2007 CDM Survey

This appendix summarizes the key results of a special survey initiated by Hydro One Distribution in December 2007. The main objective of the survey was to assess the conservation actions, if any, undertaken by Hydro One Retail customers since 2004, particularly customer conservation actions that could not be easily captured by CDM programs initiated by Hydro One Distribution, OPA or other federal and provincial government agencies. The questionnaire used for this survey is presented in Appendix I. The survey results have clearly demonstrated that Ontario residential customers are taking energy-efficiency actions on their own.

Survey Response Rate

- Total number of surveys sent out : 4,437
- Total number of responses : 1,742
- Overall response rate : 39.2%

Participation in conservation programs

Responses show increasing customer participation in CDM programs offered by Hydro One and other organisations.

Programs Offered by	2004	2005	2006	2007
Hydro One Distribution	10.5%	15.9%	30.9%	37.2%
Ontario Power Authority			5.8%	8.0%
Provincial Government			7.6%	9.7%
Federal Government			2.8%	3.7%

Spill-over effects

Survey results show in addition to using the coupons provided by Hydro One/OPA to purchase energy saving equipment, customers are buying additional products without coupons.

Equipment	With Coupons	Without Coupons	Ratio for Customers Not Using Coupons Versus Customer s Using Coupons
Compact Fluorescent Lights	4.36	10.69	2.5
LED	3.08	4.00	1.3
Timer	0.82	1.62	2.0
Motion Sensor	0.36	0.91	2.5
Dimmer	0.35	1.38	4.0
Ceiling Fan	0.51	1.49	2.9

Furnace Filter	1.21	4.82	4.0
Thermostat	0.69	0.84	1.2
Other	1.12	1.92	1.7

Conservation Culture

Results show customers are becoming increasingly aware of the need to conserve and are adopting such habits, especially starting in 2006 and 2007.

Conservation Action	2003	2004	2005	2006	2007
Use programmable thermostat	38%	42%	47%	53%	57%
Set back thermostat during the day and when away	65%	71%	75%	80%	82%
Set back thermostat during the night	63%	69%	72%	77%	80%
Turn off ac when not at home	39%	43%	48%	53%	56%
Natural cooling	68%	73%	77%	82%	85%
Maintained of ac and furnace filter	55%	59%	63%	67%	69%
Switch to non - electric space heating equipment	22%	25%	27%	29%	30%
Insulate electric water heater and pipes	34%	37%	40%	43%	46%
Use cold water doing laundry	49%	54%	62%	70%	75%
Switch to non electric water heating equipment	22%	24%	25%	25%	26%
Use CFLs or other energy efficiency lights	34%	45%	62%	76%	81%
Turn off lights when not in use	85%	90%	91%	95%	96%
Use an indoor timer	25%	27%	29%	30%	31%
Use an outdoor timer	36%	39%	43%	45%	48%
Use a dimmer switch	45%	48%	51%	53%	55%
Use a motion sensor	36%	39%	42%	45%	46%
Switch to LED holiday lights	8%	12%	23%	45%	56%
Switch to other LED lights	4%	3%	6%	11%	14%
Use timer on pool pump or heater	7%	8%	9%	10%	11%
Solar blanket	11%	12%	13%	14%	15%
Hang clothes to dry	54%	57%	61%	63%	65%
Wash dishes by hand	46%	48%	51%	53%	55%
Upgrade windows / door to prevent air leakage	32%	38%	40%	46%	48%
Air sealing and weatherization	37%	41%	47%	52%	54%
Other timers	11%	11%	12%	13%	15%

The following table highlights the top five conservation actions that were adopted by Hydro One Retail customers over the last 4 years. The figures in each year show the incremental change in customer adoption rate for each conservation action. For example, 4% of the survey respondents said they had switched to the LED holiday lights in 2004,

12% said they had switched in 2005 and another 22% of respondents said they had switched in 2006. By 2007, 56% of survey respondents said they used the LED holiday lights.

Conservation Action	2004	2005	2006	2007
Switch to LED holiday lights	4.0%	11.6%	21.5%	10.7%
Use CFLs or other energy efficiency lights	11.4%	16.8%	13.6%	5.7%
Use cold water doing laundry	4.9%	7.8%	8.4%	4.5%
Use programmable thermostat	4.3%	4.6%	5.9%	4.3%
Upgrade windows / door to prevent air leakage	5.9%	1.8%	5.7%	1.7%

Appendix I: Hydro One 2007 CDM Survey Questionnaire

Customer Account Number:

Postal Code:

Hydro One: Equipment Survey Follow–up Questions

1) Please identify the year(s) you participated in any conservation programs provided by the various organizations below **by placing an "X" in the boxes below.**

Examples of conservation programs include:

- financial incentives (such as coupons, rebates or sample products for energy efficient appliances and compact fluorescent lights)
- holiday LED lights exchange
- free disposal of old refrigerator or air conditioner
- energy efficiency equipment, such as real time monitors
- sales tax rebate offered by the Government of Ontario
- grants or loans for home energy efficiency improvements offered by the federal or provincial government

If no actions have been taken, please proceed directly to Question 2.

	2004	2005	2006	2007
Hydro One				
Ontario Power Authority				
Government of Ontario				
Government of Canada				
Other organizations: (Please specify below)				

2) Please indicate the number of items purchased in the last two years.

Energy Saving Equipment	Number purchased with coupons or rebates	Number purchased without coupons or rebates
Compact fluorescent light		
LED holiday lights (number of strings)		
Timer		
Motion sensor		
Dimmer switch		
Ceiling fan		
Furnace filter		
Programmable thermostat		
Other (Please specify below)		

3) Please identify all conservation actions you have undertaken that are **NOT** related to the initiatives identified in Question 1 for each of the time periods shown. **Please check all appropriate boxes with an "X".**

	Before 2004	2004	2005	2006	2007
Heating and Cooling					
Use a programmable thermostat					
Set back your home thermostat during the day and when away					
Set back your home thermostat during the night					
Turn off air-conditioner when not at home					
Use a fan or open windows instead of using air conditioner					
Regular maintenance of air conditioning such as changing or cleaning the furnace filter					
Switch to non-electric space heating equipment					
Electric water heating					
Insulate electric water heater and pipes					
Use cold water doing laundry					
Switch to non-electric water heating equipment					

Lighting					
Use compact fluorescent lights or other energy saving bulbs					
Turn off lights when not required					
Use timer for indoor light					
Use timer for outdoor light					
User a dimmer switch					
Use motion sensor					
Switch to LED holiday light					
Switch to other LED light					
Pool					
Use timer on the pool pump or heater					
Use insulating or solar blanket to keep the pool water warm					
Other actions					
Hang clothes to dry outside					
Wash dishes by hand					
Upgrade windows/doors etc. to prevent air leakage					
Air sealing and weatherization					
Control other equipment with timers?					
Other: (Please specify below)					

4) Please indicate if you undertook any conservation actions after receiving the following brochures. **Please check all appropriate boxes with an "X".**

		Year action taken				No action taken
Topic	**Brochure name**	**2004**	**2005**	**2006**	**2007**	
Heating	Keep Warm, Save Energy Too					
Cooling	Keep Cool, Save Energy Too					
Lighting	Live Brightly, Save Energy Too					
Caulking	Keep Comfortable, Save Energy Too					
Appliances	Use Appliances Wisely, Control Energy Costs					
Landscaping	Plant Wisely, Save Energy Too					
Windows	Let Light In, Save Energy Too					
Hot Water	Make Every Drop of Your Hot Water Count					
Metering	Electricity Meter and Meter Reading					
General	Energy Conservation in Your Home					

Appendix J: Net Load Impact Analysis for Embedded LDC Customers

This appendix summarizes the net load impact analysis for the embedded LDC customers in 2005 and 2006. At the time this report is prepared, data for 2007 is not yet available. Due to the lack of information, no analysis was done for the embedded direct customers. The CDM impacts discussed in this appendix therefore should be considered as conservative because the CDM impacts attributed to embedded directs are not yet considered.

The CDM impact analysis for the embedded LDC customers presented in this appendix includes the following:

- Conservation programs initiated by the embedded LDCs (Tables J2 and J3)
- Conservation programs launched by other organizations such as the OPA (Table J4) and federal and provincial government (Table J5)
- Conservation actions initiated by customers of the embedded LDCs that have not been captured elsewhere (Tables J6 and J7)

Table J1: CDM Impact Analysis for Embedded LDC Customers (GWh)

	Organization				Total	
Year	**LDC Programs**	**OPA Programs**	**Government Programs**	**Customer Conservation Actions**	**Annual Energy Savings**	**Cumulative Energy Savings**
2005	16	n/a	n/a	n/a	16	16
2006	16	1.5	26.5	60.	104	120
Total	**32**	**1.5**	**26.5**	**60**	**120**	

N/A denotes that CDM results are not available. Savings presented in this table are therefore conservative.

Table J1 summarized the analysis presented in Tables J2 to J7. Results show that at least 120.3 GWh of CDM savings were identified for the embedded LDC customers by the end of 2006 using the 1.0% natural conservation assumption for customer conservation actions. If the 0.4% natural conservation assumption is used, the CDM savings could be at least 145.3 GWh in 2006.

Table J2: Program Results Initiated by Embedded LDCs in 2005

Utility	Total peak demand saved (MW)	Total energy saved(GWh)
Centre Wellington Hydro	0.0	0.1
Collus	0.0	0.2
E.L.K. Energy Inc	0.0	0.0
Essex Powerlines Corp	0.6	3.1
Grand Valley	0.0	0.1
Grimsby Powerlines Inc	0.0	0.1
Guelph Hydro Electric Systems Inc	0.2	2.4
Halton Hills Hydro	0.1	0.5
Hydro 2000 Inc	0.0	2.2
Innisfil Hydro	0.0	0.1
Kitchener Wilmot Hydro Inc	0.6	4.3
Lakefront	0.0	0.4
Lakeland	0.0	0.4
Midland	0.2	0.7
Orangeville	0.0	0.0
Orilla	0.0	0.3
Ottawa River Power Corp	0.0	0.1
Parry Sound	0.0	0.0
Rideau St. Lawrence	0.0	0.1
Tay Hydro	0.1	0.0
Terrace Bay Superior Wires Inc	0.0	0.1
Veridian	0.0	0.0
Wasaga	0.0	0.1
Wellington North	0.0	0.3
Westario	0.0	0.2
Total	2.0	15.7

Source: Conservation and Demand Management Plan Annual Reports, Appendix C to December 31, 2005, 9RP-2004-0203\EB-2005-0198 filed March 31st, 2005.

Table J3: Program Results Initiated by Embedded LDCs in 2006

Utility	Total peak demand saved (MW)	Total energy saved (GWh)
Centre Wellington hydro	0.1	0.6
Collus	0.2	1.2
E.L.K. Energy Inc	0.0	0.0
Essex Powerlines Corp	0.6	2.5
Grand Valley	0.0	0.0
Guelph Hydro Electric Systems Inc	0.5	1.4
Halton Hills Hydro	0.0	1.2
Hydro 2000 Inc	0.0	0.0
Innisfil Hydro	4.8	0.0
Kitchener Wilmot Hydro Inc	1.4	0.0
Lakefront	0.1	1.1
Lakeland	0.3	1.6
Midland	0.1	1.0
Orangeville	0.0	0.5
Orilla	0.5	0.9
Ottawa River Power Corp	0.0	0.4
Parry Sound	0.0	0.6
Renfrew	0.0	0.1
Rideau St. Lawrence	0.1	0.5
Sioux look out	0.0	0.0
Tay Hydro	0.1	0.0
Terrace Bay Superior Wires Inc	0.0	0.1
Veridian	0.0	0.0
Wasaga	0.1	0.2
Wellington North	0.0	0.2
Westario	0.4	2.0
Total	**9.5**	**16.3**

Source: Conservation and Demand Management Plan Annual Reports, Appendix C to December 31, 2005, 9RP-2004-0203\EB-2005-0198 filed March 31st, 2006.

Table J4: OPA CDM Program Results for Embedded LDCs in 2006

OPA Program	Total Annual GWh savings	Total Annual MW savings	Embedded LDC Share of Energy Savings (GWh)	Embedded LDC Share of Peak Savings (MW)
Every Kilowatt Counts	358.0	84.3	26.89*	6.33
Cool Savings Rebate	10.4	10.7	0.78	0.80
Hot Savings Rebate	3.7	3.0	0.28	0.22
Secondary Refrigerator Retirement	5.6	2.6	0.42	0.20
Total	377.7	100.5	**28.37**	**7.55**

Source: 2006 Conservation Bureau Annual Report. Please note that results from Every Kilowatt Counts have already been included in the LDC Annual CDM reports shown in Table J3. The additional energy contribution, not added elsewhere, is about 1.48 GWh and the peak contribution is about 1.22 MW.

Table J5: Program Savings for Embedded LDCs from Federal and Provincial Governments in 2006:

Federal / Provincial	Federal and Provincial Programs	Electricity Saved (GWh)	Peak Load Saved (MW)	Embedded LDC Share (GWh)	Embedded LDC Share (MW)
Federal	Commercial Building Incentive Program	1.4	0.2	0.1	0.0
Federal	Industrial building Incentive Program `	16.6	4.2	1.2	0.3
Federal	Canadian Industry Program for Energy Conservation (CIPEC) - Industrial Energy Audit Incentive	90.4	13.9	6.3	1.0
Federal	Canadian Industry Program for Energy Conservation (CIPEC) - Dollars to Sense Training Workshop	132.3	20.4	9.3	1.4
Federal	R-2000 New Housing Certification Program	0.4	0.1	0.0	0.0
Federal	Energuide for New Homes	1.0	0.1	0.1	0.0
Federal	Energuide for Existing Homes	18.9	2.0	1.5	0.2
Federal	Energy Star Labelling Program	48.4	5.2	3.9	0.4
Provincial	Green Municipal Fund	51.2	12.8	2.6	0.6
Provincial	Building Retrofits and Upgrades : ORC Buildings	7.1	1.8	0.4	0.1
Provincial	Building Retrofits and Upgrades : Ministry Buildings	11.7	2.9	0.6	0.1
Provincial	Detention Centres	2.4	-	0.1	-

Provincial	Co-generation Sites for Provincial Buildings	5.4	0.6	0.3	0.0
Provincial	Cool Shops	2.6	1.8	0.1	0.1
Provincial	EcoSchools	0.5	0.1	0.0	0.0
Provincial	Reduce the Juice	1.4	0.2	0.1	0.0
Total		391.5	66.2	26.4	4.3

Source: "Overview and Analysis of Ontario Provincial and Federal Electricity Conservation and Efficiency Initiatives, Marbek Resource Consultants, July 2007

Assuming the residential customers of the embedded LDCs are undertaking the same conservation actions on their own as Hydro One Retail customers (please see Appendix G in this report for details), net savings attributed to customer conservation efforts in 2006 net of all program-driven CDM results and natural conservation can be estimated. Tables J6 and J7 estimate the net savings using the natural conservation assumption of 1% and 0.4% respectively in 2006. Based on this analysis, net conservation savings for embedded LDC residential customers are estimated to range from 60.3 GWh to 85.3 GWh in 2006.

Table J6: Net Customer Conservation Savings Using 1% Natural Conservation

Description	Percentage	Energy (GWh)
Total energy consumption for residential customers		4062
Change in energy consumption in 2006 over 2005	-2.80%	114
Less Natural efficiency assumption of 1.0%	-1.00%	41
Less Impacts from Embedded LDCs and other programs		12
CDM impact attributed to customers' own conservation actions		60

Note: 4,062 GWh are weather-normal residential energy load in 2006 estimated for embedded LDC customers. The 12 GWh are based on Embedded LDC's residential program analysis done in this appendix.

Table J7: Net Customer Conservation Savings Using 1% Natural Conservation

Description	Percentage	Energy (GWh)
Total energy consumption for residential customers		4062
Change in energy consumption in 2006 over 2005	-2.80%	114
Less Natural efficiency assumption of 1.0%	-0.4%	16
Less Impacts from Embedded LDCs and other programs		12
CDM impact attributed to customers' own conservation actions		85

Note: 4,062 GWh are weather-normal residential energy load in 2006 estimated for embedded LDC customers. The 12 GWh are based on Embedded LDC's residential program analysis done in this appendix.

Ontario Energy Board (Board Staff) INTERROGATORY #106 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ pages 10 and 20/ Issue 1.5
In Schedule 3, page 20, Table 4, the Applicant shows the 2007 forecasted load to be 41,046 GWh before deducting the impact of CDM and 40,493 after the impact of CDM. On page 10, the Applicant forecasts its 2007 customer growth to be approximately 11,000 (9,900 in the August 15, 2007 filing).

a. Please state the Applicant's actual (non-weather corrected) 2007 GWh load and the weather corrected 2007 GWh load before deducting the impact of CDM,
b. Please state the Applicant's actual (non-weather corrected) 2007 GWh load and the weather corrected 2007 GWh load after deducting the impact of CDM, and
c. Please state the actual growth in customers in 2007 using the same approach (e.g. mid year, monthly average, etc.) that the forecast was based on.

Response

a. The actual 2007 load was 41,018 GWh and the weather corrected 2007 load was 41,082 GWh before deducting the impact of CDM. Please note the numbers provided here are estimated assuming that the CDM impact in 2007 was 554 GWh. These numbers are calculated by adding the actuals provided in (b) and the forecast CDM impact of 554 GWh. If the actual CDM impact in 2007 after detailed evaluation were to be higher or lower, the numbers presented here would be adjusted higher or lower accordingly.

b. The actual 2007 load was 40,464 GWh and the weather corrected 2007 load was 40,528 GWh. Please note that the numbers provided here are actuals and as such are net of CDM impact in 2007. Therefore, no CDM deductions are required to produce these numbers.

c. The actual growth in customers in 2007 is estimated to be about 11,750 based on information currently available.

Ontario Energy Board (Board Staff) INTERROGATORY #107 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ Appendix 3/ page 26/ Issue 1.5
In Schedule 3, Appendix 3, page 26, Hydro One presents the formula for residential energy consumption ("USERes"). Due to a printing problem, the formula can not be read. Please provide the residential energy consumption ("USERes") formula.

Response

The residential energy consumption equation as filed in Exhibit A, Tab 14, Schedule 3, Appendix 3, page 26 is provided below:

$$USE_{Res} = \sum_i \sum_j N_{i,j} * S_{i,j} * UEC_{i,j}$$

Where

- USE_{Res} is residential energy consumption
- N is the number of residential accounts
- S is the residential appliance saturation rate
- UEC is the unit energy consumption per end use
- I is the index for appliances (space heating, space cooling, water heater and base load)
- J is the index for customer types—year-round residential customers and seasonal residential customers

Ontario Energy Board (Board Staff) INTERROGATORY #108 List 1

Interrogatory

Re: Exhibit A / Tab 14 / Schedule 3 Appendix 1 – Monthly Econometric Model/ Issue 1.5

The model specification shown in Appendix 1 is described as follows:

"LRTLT = f (LGDPONT, LBPONT, D98Jan)
Where:
LRTLT = logarithm of Distribution load,
LGDPONT = logarithm of Ontario GDP in constant 1997 dollars,
LBPONT = logarithm of Ontario residential building permits in constant dollar,
D98Jan = dummy variable to account for the load impact of 1998 Ice Storm, equals 1 in January 1998 and zero elsewhere,

The output parameters from the model are presented below. The State-Space (SS) estimated parameters are not associated with standard error and t-ratios (statistical relevance test).

Seasonal Factors	State-Space (SS) parameters:
A[1]	-0.134796
K[1]	-0.568914

Non-Seasonal Factors	SS parameters:
A[1]	0.531829
K[1]	-0.345868
GDPONT[-4]	0.0784784
BPONT[-9]	0.00440215
D98JAN	-0.0150467

R-squared = 0.989, R-squared corrected for mean = 0.989, Durbin-Watson Statistics = 2.31".

a. Please describe the "State-Space approach" of regression equation modeling;
b. Please describe what econometric modeling Hydro One Networks has done for this equation and why it believes that the model specification chosen is preferred;
c. Please define the variables A[1] and K[1];
d. Please provide the monthly econometric model expressed mathematically in its full form showing all variables and parameters.

Response

a. The State-Space approach is a multivariate regression model that gives more weight to the most recent information and as such has a better predictive ability for the short term. The State-Space model was first used in the late 1980's by the former Ontario Hydro forecasting staff to prepare the monthly forecast for up to 24 months. For details of the State-Space model, please refer to Chapter 7 of the book entitled "Applied Statistical Forecasting" written by Robert L. Goodrich released by Business Forecast Systems in 1992.

b. The same State-Space modeling approach and equation has been used for the past 18 years by the Hydro One Distribution forecasting staff. During these years, different specifications were examined in terms of variables to be included in the model, the lag structure of the variables, and the functional form of the equation. Standard regression criteria (e.g., R-square, BIC (Baysian Information Criterion), Durbin-Watson Statistics, etc.) were used in selecting the final form of the equation.

c. These parameters (A[1] and K[1]) quantify the impact of "seasonal factors" on load.

d. The base functional form of the regression analysis is presented below:

D1[Log(Load)] = f{D1(Log(GDP(-4))], D1[Log(Building Permits(-9)), D1(Jan88)], D12(Log(GDP)], D12[Log(Building Permits), D12)Jan88)]}

where
D1 is the 1-month difference operator;
D12 is 12-month difference operator to take into account seasonal factors.

The above algorithm estimates the impact of GDP, building permits, and the unique-event dummy variable (Jan88) in a non-linear way taking into account seasonal and non-seasonal influences. There is no expressible link between the model variables and parameters except the sign of the estimated coefficients that reflect whether the variable has a positive or negative effect on the dependent variable.

Ontario Energy Board (Board Staff) INTERROGATORY #109 List 1

Interrogatory

Ref: Exhibit A / Tab 14 / Schedule 3 Appendix 2 – Annual Econometric Model/ Issue 1.5

The annual econometric model is documented in Appendix 2 as follows: "LRTLT=C(1)+C(2)*LYPDPHH+C(3)*(LPELRES(-1)-LPGASRES(-1))+C(4)*LCDD+C(5)*LHDD+C(6)*LRTLT(-1)-C(4)*C(6)*LCDD(-1)-C(5)*C(6)*LHDD(-1)+C(7)*D99A+C(8)*TR+C(9)*TR2

Where:
LRTLT = logarithm of Distribution load,
LYPDPHH = logarithm of Ontario personal disposable income per household in constant $,
LPELRES = logarithm of electricity price for Ontario residential sector,
LPGASRES = logarithm of natural gas price for Ontario residential sector,
LCDD = logarithm of cooling degree days for Pearson International Airport,
LHDD = logarithm of heating degree days for Pearson International Airport,
D99A = dummy variable to account for annexation of retail customers by municipal utilities equals 1 after 1999 and zero elsewhere,
TR = a dummy variable to account for a shift in growth pattern of Distribution load, increases by 1 per year prior to 1989 and no increase afterwards,
TR2 = TR to power 2,
C(1) – C(9) = variable coefficients.

The estimated coefficients and associated statistics are presented below.

	Estimated Coefficient	Standard Error	t-ratio
C(1)	5.54891	1.273869	4.355949
C(2)	0.303905	0.119354	2.546245
C(3)	-0.055342	0.025059	-2.208471
C(4)	0.004952	0.007168	0.690828
C(5)	0.195571	0.043265	4.520272
C(6)	0.286776	0.10389	2.760383
C(7)	-0.020994	0.007506	-2.796974
C(8)	-0.100598	0.023221	-4.332256
C(9)	0.002619	0.000546	4.795182

R-squared = 0.995, Adjusted R-squared = 0,993, Durbin-Watson Statistic = 1.90."

The estimated coefficient for LCDD (natural logarithm of Cooling Degree Days) has a very small estimate and has a t-statistic of 0.69. The small t-statistic indicates that, from a

statistical test of confidence, the hypothesis that C(4) is equal to zero cannot be rejected. Please explain why LCDD is retained as an explanatory variable given its statistical insignificance and the small numerical value of the coefficient.

The annual econometric model has a double-log functional form, which is a standard one in econometrics. A double-log function form that is specified in its linear form has the characteristic that the parameters (coefficients) are constant elasticities and that the functional form, expressed in its pure (non-log) form, is a multiplicative relationship between the explanatory variables, each raised to the power of its elasticity. In other words,

$= \alpha + \beta + \delta + \varphi + \varepsilon\ 1\ 2\ 3\ \ln Y \ln X \ln X \ln X$

is equivalent to:

$Y\ e\alpha\ X\ \beta\ X\ \delta\ X\varphi\ e\varepsilon\ 1\ 2\ 3 = .$

The double-log functional form used in the annual econometric model means that heating degree days and cooling degree days, each raised to its corresponding elasticity, affect the distribution load estimate multiplicatively.

a. Please explain the theoretical basis for heating degree days and cooling degree days to interact multiplicatively in this model.
b. The model specification is also an autoregressive one, as the log of the previous year's distribution load, adjusted for heating degree days and cooling degree days, is a left-hand side variable.
c. Please describe what econometric modeling Hydro One Networks has done for this equation and why it believes that the model specification chosen is preferred.
d. Please describe what, if any, adjustments have been made to improve the model estimation due to the auto-regressive nature of the model specification.

Response

Response to Question: "Please explain why LCDD is retained as an explanatory variable given its statistical insignificance and the small numerical value of the coefficient."

The answer is two fold. First, theoretically, CDD is expected to have a direct impact on load (the higher CDD, the higher the load assuming other factors remaining the same). Consequently, the variable should be retained in the model on a theoretical basis. Second, it would cause no harm to retain a variable in the model if its coefficient is not statistically significant. The lack of statistical significance could be due to inverse correlation between CDD and HDD and such an inverse relationship could continue during the forecast period. Consequently, any imprecision in the estimated coefficients of CDD and HDD would cancel-out each other during both the sample and forecast periods.

Response:

a. The heating and cooling degree day are formulated to interact multiplicatively with other variables in this model to correct for a changing scale factor over time. As time goes by, the load increases (decreases) reflecting an expanding (contracting) customer base that, in turn, require more (less) heating and cooling load.

b. That is correct.

c. Hydro One Distribution looked at different specifications in terms of variables to be included in the model, the lag structure of variables, and the functional form of equation. Standard regression criteria (e.g., R-square, t-ratios, Durbin-Watson Statistics etc.) were used to select the model with the best fit.

d. The Ordinary Least-Squares method was used to estimate the model. This method is appropriate given that the lagged dependent variable (the autoregressive component) is not contemporaneously correlated with the other variables on the right-hand side of the equation and the error term. Residual analysis (as reflected in the good fit of the model) indicated that the lagged dependent variable had successfully picked-up the autoregressive component of the load so that no further adjustment was required.

Ontario Energy Board (Board Staff) INTERROGATORY #110 List 1

Interrogatory

Ref: Exhibit A / Tab 14 / Schedule 3 Appendix 3 – End-Use Model – Residential Sector/ Issue 1.5
The forecasting equation for the residential sector is described as follows:

"The residential energy forecast is determined by forecasting the number of accounts times appliance saturation rates and unit energy consumption expressed in the following equation:

$$USE_{Res} = \sum_i \sum_j N_{i,j} * S_{i,j} * UEC_{i,j}$$

Where:
•• USE_{Res} is residential energy consumption
•• N is the number of residential accounts
•• S is the residential appliance saturation rate
•• UEC is the unit energy consumption per end use
•• I is the index for appliances (space heating, space cooling, water heater and base load)
•• J is the index for customer types—year-round residential customers and seasonal residential customers".

a. Please provide the residential sector equation in its full mathematical expression, showing the functional form and all explanatory variables and coefficients.
b. Please describe the estimation methodology used for the model coefficient estimates.

Response

a. The residential energy forecast is expressed as the following equation:

$$USE_{Res} = \sum_i \sum_j N_{i,j} * S_{i,j} * UEC_{i,j}$$

Where

- USE_{Res} is residential energy consumption
- N is the number of residential accounts
- S is the Residential Appliance Saturation Rate
- UEC is the Unit Energy Consumption per end use
- I indexes 5 appliances (space heating, space cooling, water heater and base load)
- J indexes two residential customer types—Year round residential customers and Seasonal residential customers

A detailed description of the end-use equation is provided below. Since this is an end-use equation, there are no coefficients associated with the variables.

Total energy consumption=Energy consumption for year-round customers + Energy consumption for seasonal customers=(1)+(2)=(3)+(4)+(5)+(6)+(7)+(8)+(9)+(10)
Where:
(1) Year-Round customers energy consumption=space heating consumption + space cooling consumption + water heater consumption + baseload consumption
(2) Seasonal customers energy consumption=space heating consumption + space cooling consumption+ water heater consumption + baseload consumption
(3) Year-round customers' space heating consumption=year round customer number* space heating saturation rate* unit energy consumption of space heating
(4) Year-round customers' space cooling consumption=year round customer number*space cooling saturation rate* unit energy consumption of space cooling
(5) Year-round customers' water heater consumption=year round customer number* water heater saturation rate* unit energy consumption of water heater
(6) Year-round customers' Baseload consumption=year round customer number*baseload saturation rate* unit energy consumption of baseload
(7) Seasonal customers' space heating consumption=seasonal customer number* space heating saturation rate* unit energy consumption of space heating
(8) Seasonal customers' space cooling consumption=seasonal customer number*space cooling saturation rate* unit energy consumption of space cooling
(9) Seasonal customers' water heater consumption= seasonal customer number* water heater saturation rate* unit energy consumption of water heater
(10) Seasonal customers' Baseload consumption= seasonal customer number*baseload saturation rate* unit energy consumption of baseload

b. There is no coefficient estimation involved in this end-use equation.

Ontario Energy Board (Board Staff) INTERROGATORY #111 List 1

Interrogatory

Ref: Exhibit B1 Tab 1 Schedule 1, Section 2.0 – Capital Structure/ Issue 2.1
Hydro One Networks states that its "deemed capital structure for rate making purposes is 60% debt and 40% common equity. This capital structure was determined by the Ontario Energy Board as being appropriate for all distributors in its December 20, 2006 [Board Report].

Section 4.1 and Table 5 of the Board Report specified a transition, beginning in 2008, to the common deemed capital structure of 60:40 from the current Rate Base size-related deemed capital structure. For a distributor with a rate base over $1 Billion, like Hydro One Networks, the transitional deemed capital structure for 2008 would be 62.5% debt (of which 58.5% would be long-term debt and a deemed 4.0% short-term debt component) and 37.5% equity.

a. Please provide Hydro One Networks' reasons for proposing a 60% debt and 40% equity structure for 2008 rates.
b. Please provide the deemed capital structure approved by the Board for setting Hydro One Networks' transmission rates in its most recent transmission rate application considered in EB-2006-0501.

Response

a. Hydro One Distribution's approved capital structure in its 2006 rate order was 60% debt and 40% equity, therefore no transition to the new capital structure is required.

b. The Board approved a capital structure of 60% debt and 40% equity for Hydro One Transmission in its most recent rate application, EB-2006-0501. In its Decision, the Board stated "the Board will also apply the distribution capital structure to Hydro One Transmission"

Ontario Energy Board (Board Staff) INTERROGATORY #112 List 1

Interrogatory

Ref: Exhibit B2 Tab 1 Schedule 1 – Capital Structure/ Issue 2.1
Please re-submit the exhibit in the following format, for each of the years:

a. 2004 actual
b. 2005 actual
c. 2006 Board-approved
d. 2006 actual
e. 2007 bridge; and
f. 2008 test year.

Year

	(1) $	(2) %	(3) Rate (%)	(2) X (3)
Debt				
Short-term				
Long-term				
Total Debt				
Equity				
Common Equity				
Preferred Shares				
Total Equity				
Total Capital		100%	Weighted Average Cost of Capital	

Response

The actual and projected capital structure data for 2004 to 2007 contained in Exhibit B2-1-1 is as at year end. For purposing of calculating cost of capital and for consistency with the 2006 Board-approved capital structure, the data shown in the table below for 2004 to 2007 is an average for each year. The data for the 2008 test year is consistent with Exhibit B1-1-1.

2004 Actual	(1) $	(2) %	(3) Rate (%)	(4) (2)x(3)
Short-term	113	3.5%	2.30%	0.08%
Long-term	1854	57.7%	6.90%	3.98%
Total Debt	1967	61.2%		4.06%
Equity				
Common Equity	1150	35.7%	9.88%	3.53%

Preferred Shares	99	3.1%	5.50%	0.17%
Total Equity	1249	38.8%		3.70%
Total Capital	3216	100.0%		7.76%

2005 Actual	(1) $	(2) %	(3) Rate (%)	(4) (2)x(3)
Short-term	51	1.5%	2.81%	0.04%
Long-term	1955	57.9%	6.68%	3.86%
Total Debt	2006	59.4%		3.90%
Equity				
Common Equity	1255	37.1%	9.88%	3.67%
Preferred Shares	118	3.5%	5.44%	0.19%
Total Equity	1373	40.6%		3.86%
Total Capital	3379	100.0%		7.76%

2006 Board Approved	(1) $	(2) %	(3) Rate (%)	(4) (2)x(3)
Short-term	233	6.3%	3.33%	0.21%
Long-term	1994	53.7%	6.24%	3.35%
Total Debt	2227	60.0%		3.56%
Equity				
Common Equity	1336	36.0%	9.00%	3.24%
Preferred Shares	148	4.0%	5.50%	0.22%
Total Equity	1485	40.0%		3.46%
Total Capital	3712	100.0%		7.02%

2006 Actual	(1) $	(2) %	(3) Rate (%)	(4) (2)x(3)
Short-term	34	1.0%	4.16%	0.04%
Long-term	2022	57.6%	6.17%	3.55%
Total Debt	2056	58.5%		3.59%
Equity				
Common Equity	1320	37.6%	9.00%	3.38%
Preferred Shares	137	3.9%	5.38%	0.21%
Total Equity	1457	41.5%		3.59%
Total Capital	3513	100.0%		7.18%

2007 Bridge	(1) $	(2) %	(3) Rate (%)	(4) (2)x(3)
Short-term	84	2.2%	4.39%	0.10%
Long-term	2131	57.0%	5.84%	3.33%
Total Debt	2215	59.2%		3.43%
Equity				

Common Equity	1390	37.1%	9.00%	3.34%
Preferred Shares	137	3.7%	5.38%	0.20%
Total Equity	1527	40.8%		3.54%
Total Capital	3742	100.0%		6.97%

2008 Test	(1) $	(2) %	(3) Rate (%)	(4) (2)x(3)
Short-term	175	4.0%	4.74%	0.19%
Long-term	2326	53.1%	5.71%	3.03%
Deemed Long-term	128	2.9%	5.69%	0.17%
Total Debt	2629	60.0%		3.39%
Equity				
Common Equity	1753	40.0%	8.64%	3.46%
Preferred Shares		0.0%		0.00%
Total Equity	1753	40.0%		3.46%
Total Capital	4382	100.0%		6.84%

1

Ontario Energy Board (Board Staff) INTERROGATORY #113 List 1

Interrogatory

Ref: Ex A/Tab 9/Sch 2/ Issue 6.1
Please provide the 2007 and 2008 proforma balance sheets for Hydro One Distribution.

Response

Pro forma balance sheets for Hydro One Distribution for 2007 and 2008, consistent with the pro forma income statements provided in Exhibit A-9-2, are provided below:

$ millions	**2007**	**2008**
Fixed assets	3,981	4,350
Current Assets	506	556
Other assets	232	174
Total assets	**4,719**	**5,080**
Long-term debt	2,000	2,302
Current liabilities	652	584
Other liabilities	509	535
Equity	1,557	1,659
Total liabilities / equity	**4,719**	**5,080**

Ontario Energy Board (Board Staff) INTERROGATORY #114 List 1

Interrogatory

Ref: ExA/Tab17/Sch1 and ExhD/Tab4/Sch1/ Issue 6.1
Hydro One states that the interest rate used for Construction Work in Progress (CWIP) reflects the Board's letter of direction in EB-2006-0117, effective November 28, 2006.

a. Did Hydro One Distribution implement the Board-prescribed interest rate, as per the Board's letter to LDCs dated November 28, 2006, for construction work in progress (CWIP) since May 1, 2006?
b. If not, when did Hydro One implement the prescribed interest rate methodology? And, what is the impact on rate base, revenue requirement, and CWIP be if Hydro One implemented this decision as of May 1, 2006?

Response

a. Hydro One wrote to the OEB on December 12, 2006 expressing concern regarding the retroactive nature of the interest rate change and the message that could send to the financial community. Hydro One indicated to the OEB its intention to implement the prescribed interest rates on a prospective basis.

b. Hydro One Distribution implemented the Board-prescribed interest rate for CWIP on January 1, 2007.

The estimated impact of implementing the Board-prescribed interest rate for CWIP on May 1, 2006 rather than January 1, 2007 would have been a decrease in interest capitalized and a corresponding decrease in capital expenditures of about $0.8M during 2006.

Implementing the Board-prescribed rate on May 1, 2006 would therefore have reduced 2008 rate base by about $0.8M, resulting in a decrease in 2008 revenue requirement of less than $0.1M.

Ontario Energy Board (Board Staff) INTERROGATORY #115 List 1

Interrogatory

Ref: ExF/Sch1/Tab1// Issue 6.1

a. Please list and provide a brief description of all outstanding deferral and variance accounts. This includes the deferral and variance accounts not being requested for disposition.

b. Please provide the balances of all regulatory deferral and variance accounts, including those not being requested for disposition, for the period ending December 31st, 2006.

Response

a.

Regulatory Asset Recovery	Represents recovery of Hydro One Distribution Regulatory Assets per Board Decisions.
C&DM	Represents cost of Hydro One C&DM approved programs net of recoveries received.
Smart Meters	Relates to costs associated with the Hydro One Smart Meter program.
RSVA	Represents the difference between revenue and costs of power on commodity that Hydro One is going to collect from its customers.
RCVA	Represents the difference between amounts billed in relation to service transaction requests and the incremental costs associated with those activities
Cat Lake	Relates to costs associated with providing service to Cat Lake customers offset by revenue collected from Cat Lake customers. On August 14, 2006 Hydro One assumed operational control of the Transmission and Distribution assets associated with Cat Lake Power per the OEB's Decision and Order (EB-2006-0180) dated July 21, 2006
OEB Costs	Reflects the excess of OEB quarterly billings over amounts included in current revenue requirement.
RRRP	Represents net amounts collected from IESO as a fixed charge of .1 cents per KWh. for rural and remote rate assistance.
Tax Changes	Represents the tax impact from a legislative or regulatory change to the tax rates from rates used to calculate the current revenue requirement.
Environmental	Represents the net present value of estimated future cash flows expected to be required to discharge Hydro One Distribution's financial obligations associated with PCB management and the remediation of contaminated lands.

b. Balances as at December 31, 2006:

Regulatory Asset Recovery	$142.2M
C&DM	$(19.1)M
Smart Meters	$4.2M
RSVA	$(2.2)M
RCVA	$(0.5)M
Cat Lake	$0.4M
OEB Costs	$(0.9)M
RRRP	$1.0M
Tax Changes	$(2.8)M
Environmental	$45.4M

Ontario Energy Board (Board Staff) INTERROGATORY #116 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1 and ExF1/T2/Sch1/ Issue 6.1
Hydro One is applying for disposition of regulatory variance accounts in ExF1/Tab1/Sch1/P2 and ExF1/T2/Sch1 /page1.

Provide the information as shown in the attached continuity schedule for regulatory assets and provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on ExF1/Tab1/Sch1/Page 2 and ExF1/T2/Sch1/Page1. In the continuity schedule, please breakout the sub-accounts for 1508. Please note that forecasting principal transactions beyond December 31, 2006 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

Response

Please refer to the attached (Attachment A)completed continuity schedule.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY		**LICENCE NUMBER**	ED-XXXX-XXXX
NAME OF CONTACT		**DOCID NUMBER**	EB-200X-XXXX
E-mail Address			
VERSION NUMBER	v3.0	**PHONE NUMBER**	
Date		**(extension)**	

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

			2005								
Account Description		**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [6]	**Transactions (reductions) during 2005, excluding interest and adjustments** [6]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
RSVA - Wholesale Market Service Charge		1580	$ 485,000	$ 8,325,000				$ 8,810,000	$ 24,000	$ 171,000	$ 195,000
RSVA - One-time Wholesale Market Service		1582	$ 1,011,000	$ 1,238,000				$ 2,249,000	$ 45,000	$ 113,000	$ 158,000
RSVA - LV		1550									
RSVA - Retail Transmission Network Charge		1584	$ (11,324,000)	$ (7,730,000)				$ (19,054,000)	$ (481,000)	$ (1,196,000)	$ (1,677,000)
RSVA - Retail Transmission Connection Charge		1586	$ (14,082,000)	$ (10,324,000)				$ (24,406,000)	$ (608,000)	$ (1,528,000)	$ (2,136,000)
	Sub-Totals		$ (23,910,000)	$ (8,491,000)		$ -	$ -	$ (32,401,000)	$ (1,020,000)	$ (2,440,000)	$ (3,460,000)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ 1,179,000	$ 2,211,000				$ 3,390,000	$ 18,000	$ 128,000	$ 146,000
Other Regulatory Assets - Sub-Account - Pension Contributions		1508	$ 33,218,000	$ 38,248,000				$ 71,466,000	$ 1,164,000	$ 3,866,000	$ 5,030,000
Other Regulatory Assets - Sub-Account - Other [7] (RRRP)		1508	$ 2,352,000		$ (3,159,000)			$ (807,000)	$ (75,000)	$ 69,000	$ (6,000)
Other Regulatory Assets - Sub-Account - Other [7] (meu rate mitigation		1508	$ -	$ 825,000				$ 825,000	$ -	$ 21,000	$ 21,000
Other Regulatory Assets - Sub-Account - Other [7] Cat Lake		1508						$ -			$ -
Retail Cost Variance Account - Retail		1518	$ (432,000)	$ (130,000)				$ (562,000)	$ (45,000)	$ (40,000)	$ (85,000)
Retail Cost Variance Account - STR		1548	$ 147,000	$ 186,000				$ 333,000	$ 5,000	$ 18,000	$ 23,000
Misc. Deferred Debits		1525	$ 88,487,000		$ (7,059,000)			$ 81,428,000	$ 25,544,000	$ 2,933,000	$ 28,477,000
LV Variance Account		1550	$ 24,964,000	$ 24,392,000				$ 49,356,000	$ 902,000	$ 2,772,000	$ 3,674,000
Smart Meter Revenue Requirement (Min Funct to May 31, 2007)		1555/1556									
Smart Meter Revenue (Min Funct to May 31, 2007)		1555									
Smart Meter Revenue Requirement (Exceeding Min Funct)		1555/1556									
Smart Meter Revenue Requirement (Min Funct between June 1, 2007 and April 30, 2008)		1555/1556									
Smart Meter Revenue (Min Funct between June 1, 2007 and April 30, 2008)		1555									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital		1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries		1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs		1555						$ -			$ -
Smart Meter OM&A Variance		1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries		1565	$ 1,037,000		$ (24,654,000)			$ (23,617,000)	$ 9,000	$ 16,000	$ 25,000
CDM Contra		1566						$ -			$ -
Qualifying Transition Costs [5]		1570		n/a	n/a			$ -			$ -
Pre-Market Opening Energy Variances Total [5]		1571		n/a	n/a			$ -			$ -
Extra-Ordinary Event Costs		1572						$ -			$ -
Deferred Rate Impact Amounts		1574						$ -			$ -
Other Deferred Credits		2425						$ -			$ -
	Sub-Totals		$ 150,952,000	$ 65,732,000	$ (34,872,000)	$ -	$ -	$ 181,812,000	$ 27,522,000	$ 9,783,000	$ 37,305,000
Deferred Payments in Lieu of Taxes		1562				**see PILs reconciliation requested**					
2006 PILs & Taxes Variance		1592				**see PILs reconciliation requested**					
	Sub-Totals					**see PILs reconciliation requested**					
	Total		$ 127,042,000	$ 57,241,000	$ (34,872,000)	$ -	$ -	$ 149,411,000	$ 26,502,000	$ 7,343,000	$ 33,845,000
The following is not included in the total claim but is included on a memo basis:											
Deferred PILs Contra Account [8]		1563				**see PILs reconciliation requested**					
RSVA - Power (including Global Adjustment)		1588						$ -			$ -
RSVA - Power - Sub-Account - Global Adjustment [4]		1588	$ -	$ (4,926,000)				$ (4,926,000)	$ -	$ (216,000)	$ (216,000)
Recovery of Regulatory Asset Balances		1590	$ 121,954,000		$ (40,871,000)			$ 81,083,000	$ (725,000)	$ 7,877,000	$ 7,152,000

C:\Documents and Settings\186402\Desktop\100-130\[H-1-116 Attachment.xls]Continuity Schedule

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2006 closing principal balance.

Note 1 Values reflect interest adjustments requested by the Board in RP-2005-0020 for Deferred Pension account and MEU Rate Mitigation account

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	
NAME OF CONTACT	
E-mail Address	
VERSION NUMBER	v3.0
Date	

Account Description	Account Number	2006 Opening Principal Amounts as of Jan-1-06	2006 Transactions (additions) during 2006, excluding interest and adjustments [6]	2006 Transactions (reductions) during 2006, excluding interest and adjustments [6]	2006 Adjustments during 2006 - instructed by Board [2]	2006 Adjustments during 2006 - other [3]	2006 Transfer of Board-approved amounts to 1590 as per 2006 EDR	2006 Closing Principal Balance as of Dec-31-06	2006 Opening Interest Amounts as of Jan-1-06	2006 Interest Jan-1 to Dec31-06	2006 Transfer of Board-approved amounts to 1590 as per 2006 EDR	2006 Closing Interest Amounts as of Dec-31-06
											Note 1	
RSVA - Wholesale Market Service Charge	1580	$ 8,810,000	$ (35,838,000)				$ 3,533,000	$ (23,495,000)	$ 195,000	$ (253,000)	$ (290,000)	$ (348,000)
RSVA - One-time Wholesale Market Service	1582	$ 2,249,000	$ -				$ (2,249,000)	$ -	$ 158,000	$ 56,000	$ (214,000)	$ -
RSVA - LV	1550		$ 832,000				$ -	$ 832,000		$ 15,000	$ -	$ 15,000
RSVA - Retail Transmission Network Charge	1584	$ (19,054,000)	$ 3,126,000				$ 23,159,000	$ 7,231,000	$ (1,677,000)	$ (314,000)	$ 2,321,000	$ 330,000
RSVA - Retail Transmission Connection Charge	1586	$ (24,406,000)	$ 28,000				$ 29,468,000	$ 5,090,000	$ (2,136,000)	$ (483,000)	$ 2,965,000	$ 346,000
Sub-Totals		$ (32,401,000)	$ (31,852,000)		$ -	$ -	$ 53,911,000	$ (10,342,000)	$ (3,460,000)	$ (979,000)	$ 4,782,000	$ 343,000
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 3,390,000	$ 759,000				$ (4,976,000)	$ (827,000)	$ 146,000	$ 39,000	$ (234,000)	$ (49,000)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 71,466,000	$ 12,167,000				$ (83,633,000)	$ -	$ 5,030,000	$ (934,000)	$ (4,096,000)	$ -
Other Regulatory Assets - Sub-Account - Other [7] (RRRP)	1508	$ (807,000)	$ 1,784,000					$ 977,000	$ (6,000)	$ 2,000		$ (4,000)
Other Regulatory Assets - Sub-Account - Other [7] (meu rate mitigation	1508	$ 825,000	$ 367,000				$ (1,192,000)	$ -	$ 21,000	$ 13,000	$ (34,000)	$ -
Other Regulatory Assets - Sub-Account - Other [7] Cat Lake	1508	$ -	$ 367,000					$ 367,000	$ -	$ 3,000		$ 3,000
Retail Cost Variance Account - Retail	1518	$ (562,000)	$ (451,000)				$ 525,000	$ (488,000)	$ (85,000)	$ (26,000)	$ 96,000	$ (15,000)
Retail Cost Variance Account - STR	1548	$ 333,000	$ 107,000				$ (407,000)	$ 33,000	$ 23,000	$ 9,000	$ (31,000)	$ 1,000
Misc. Deferred Debits	1525	$ 81,428,000		$ (11,581,000)				$ 69,847,000	$ 28,477,000	$ 3,043,000		$ 31,520,000
LV Variance Account	1550	$ 49,356,000	$ 8,096,000				$ (57,452,000)	$ -	$ 3,674,000	$ 1,315,000	$ (4,989,000)	$ -
Smart Meter Revenue Requirement (Min Funct to May 31, 2007)	1555/1556		$ 6,053,000					$ 6,053,000	$ -	$ 139,000		$ 139,000
Smart Meter Revenue (Min Funct to May 31, 2007)	1555			$ (2,490,000)				$ (2,490,000)	$ -	$ (57,000)		$ (57,000)
Smart Meter Revenue Requirement (Exceeding Min Funct)	1555/1556		$ 627,000					$ 627,000	$ -	$ 14,000		$ 14,000
Smart Meter Revenue Requirement (Min Funct between June 1, 2007 and April 30, 2008)	1555/1556		$ -					$ -	$ -			$ -
Smart Meter Revenue (Min Funct between June 1, 2007 and April 30, 2008)	1555		$ -					$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -						$ -	$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (23,617,000)	$ 4,524,000					$ (19,093,000)	$ 25,000	$ -		$ 25,000
CDM Contra	1566	$ -						$ -	$ -			$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a				$ -	$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 181,812,000	$ 34,400,000	$ (14,071,000)	$ -	$ -	$ (147,135,000)	$ 55,006,000	$ 37,305,000	$ 3,560,000	$ (9,288,000)	$ 31,577,000
Deferred Payments in Lieu of Taxes	1562					**see PILs reconciliation requested**						
2006 PILs & Taxes Variance	1592					**see PILs reconciliation requested**						
Sub-Totals						**see PILs reconciliation requested**						
Total		$ 149,411,000	$ 2,548,000	$ (14,071,000)	$ -	$ -	$ (93,224,000)	$ 44,664,000	$ 33,845,000	$ 2,581,000	$ (4,506,000)	$ 31,920,000
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account [8]	1563					**see PILs reconciliation requested**						
RSVA - Power (including Global Adjustment)	1588	$ -						$ -	$ -			$ -
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ (4,926,000)	$ 12,579,000					$ 7,653,000	$ (216,000)	$ 380,000	$ -	$ 164,000
Recovery of Regulatory Asset Balances	1590	$ 81,083,000		$ (47,937,000)			$ 93,224,000	$ 126,370,000	$ 7,152,000	$ 13,136,000	$ (4,506,000)	$ 15,782,000

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	
NAME OF CONTACT	
E-mail Address	
VERSION NUMBER	v3.0
Date	

Account Description		Account Number	Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 [9]	Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 [9]	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008	Projected Interest from Jan 1, 2007 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007	Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008	Total Claim	Ex F1/Tab 1/Sch 1/ Pg 2
RSVA - Wholesale Market Service Charge		1580	$ (1,111,000)	$ (400,000)	$ (25,354,000)	$ (34,555,000)	$ (11,250,000)	$ (1,335,000)	$ (96,000)	$ (72,590,000)	$ (72,590,000)
RSVA - One-time Wholesale Market Service		1582	$ -	$ -	$ -	$ -	$ -			$ -	$ -
RSVA - LV		1550	$ 40,000	$ 14,000	$ 901,000	$ 2,028,000	$ 830,000	$ 65,000	$ 7,000	$ 3,831,000	$ 3,831,000
RSVA - Retail Transmission Network Charge		1584	$ 342,000	$ 123,000	$ 8,026,000	$ 4,479,000	$ (11,210,000)	$ 230,000	$ (95,000)	$ 1,430,000	$ 1,430,000
RSVA - Retail Transmission Connection Charge		1586	$ 241,000	$ 87,000	$ 5,764,000	$ 1,740,000	$ (5,010,000)	$ 56,000	$ (43,000)	$ 2,507,000	$ 2,507,000
	Sub-Totals		$ (488,000)	$ (176,000)	$ (10,663,000)	$ (26,308,000)	$ (26,640,000)	$ (984,000)	$ (227,000)	$ (64,822,000)	$ (64,822,000)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		1508	$ (39,000)	$ (14,000)	$ (929,000)					$ (929,000)	$ (929,000)
Other Regulatory Assets - Sub-Account - Pension Contributions		1508			N/A					N/A	
Other Regulatory Assets - Sub-Account - Other [7] (RRRP)		1508			N/A					N/A	
Other Regulatory Assets - Sub-Account - Other [7] (meu rate mitigation		1508			N/A					N/A	
Other Regulatory Assets - Sub-Account - Other [7] Cat Lake		1508			N/A					N/A	
Retail Cost Variance Account - Retail		1518			N/A					N/A	
Retail Cost Variance Account - STR		1548			N/A					N/A	
Misc. Deferred Debits		1525			N/A					N/A	
LV Variance Account		1550			N/A					N/A	
Smart Meter Revenue Requirement (Min Funct to May 31, 2007)		1555/1556	$ 285,000	$ 103,000	$ 6,580,000	$ 4,292,000	$ 1,025,000	$ 99,000	$ 8,000	$ 12,004,000	$ 12,004,000
Smart Meter Revenue (Min Funct to May 31, 2007)		1555	$ (117,000)	$ (42,000)	$ (2,706,000)	$ (2,340,000)	$ -	$ (54,000)		$ (5,100,000)	$ (5,100,000)
Smart Meter Revenue Requirement (Exceeding Min Funct)		1555/1556	$ 30,000	$ 11,000	$ 682,000	$ 2,645,000	$ 2,300,000	$ 61,000	$ 18,000	$ 5,706,000	$ 5,706,000
Smart Meter Revenue Requirement (Min Funct between June 1, 2007 and April 30, 2008)		1555/1556	$ -	$ -	$ -	$ 11,217,000	$ 9,977,000	$ 265,000	$ 180,000	$ 21,639,000	$ 21,639,000
Smart Meter Revenue (Min Funct between June 1, 2007 and April 30, 2008)		1555	$ -	$ -	$ -	$ (7,613,000)	$ (4,382,000)	$ (180,000)	$ (79,000)	$ (12,254,000)	$ (12,254,000)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital		1555			$ -					$ -	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries		1555			$ -					$ -	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs		1555			$ -					$ -	
Smart Meter OM&A Variance		1556			$ -					$ -	
Conservation and Demand Management Expenditures and Recoveries		1565			N/A					N/A	
CDM Contra		1566			N/A					N/A	
Qualifying Transition Costs [5]		1570			N/A					N/A	
Pre-Market Opening Energy Variances Total [5]		1571			N/A					N/A	
Extra-Ordinary Event Costs		1572			N/A					N/A	
Deferred Rate Impact Amounts		1574			N/A					N/A	
Other Deferred Credits		2425			N/A					N/A	
	Sub-Totals		$ 159,000	$ 58,000	$ 3,627,000	$ 8,201,000	$ 8,920,000	$ 191,000	$ 127,000	$ 21,066,000	$ 21,066,000
Deferred Payments in Lieu of Taxes		1562								$ (4,963,000)	$ (4,963,000)
2006 PILs & Taxes Variance		1592									
	Sub-Totals				$ -					$ (4,963,000)	$ (4,963,000)
	Total		$ (329,000)	$ (118,000)	$ (7,036,000)	$ (18,107,000)	$ (17,720,000)	$ (793,000)	$ (100,000)	$ (48,719,000)	$ (48,719,000)
The following is not included in the total claim but is included on a memo basis:											
Deferred PILs Contra Account [8]		1563									
RSVA - Power (including Global Adjustment)		1588			$ -					$ -	
RSVA - Power - Sub-Account - Global Adjustment [4]		1588	$ 362,000	$ 130,000	$ 8,309,000	$ (7,653,000)	$ -	$ (656,000)	$ -	$ -	
Recovery of Regulatory Asset Balances		1590			$ 142,152,000					$ 142,152,000	

Ontario Energy Board (Board Staff) INTERROGATORY #117 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1
Hydro One stated that the amount related to the elimination of the Large Corporation Tax (LCT) was charged to account 1592 from May 1, 2006 to April 30, 2007. In July 2007, the Board released the 'APH Frequently Asked Questions' detailing how utilities were expected to account for the retroactive repeal of the LCT.

a. To what account did Hydro One book the period January 1st 2006 to April 30th 2006 repeal of the LCT?
b. If Hydro One has not recorded for the repeal of the LCT, please explain why?
c. Please provide a table similar to Exhibit F1/Tab1/Schedule1 page 5 Distribution Tax Rate Changes Account Balances to reflect the amount related to the elimination of the LCT from January 1st, 2006 to April 30th, 2007 into account1592.

Response

a. Hydro One Distribution calculated the impact of the elimination of the LCT as being a reduction in revenue requirement of $4.1M for the calendar year 2006. The full amount of this impact was booked to account 1592 over the rate year period from May 1, 2006 to April 30, 2007 (as this is the period during which Hydro One over-collected the revenue), and is included in the deferral account balance shown in Exhibit F1-1-1, Table 4.

b. See response to part a.

c. See response to part a.

Ontario Energy Board (Board Staff) INTERROGATORY #118 List 1

Interrogatory

Ref F1/Tab2/Sch1/ Issue 6.1

Usual practice is to recover regulatory deferral and variance accounts through rate riders, instead of applying the balance against the revenue requirement. Please provide allocations and rate riders for each regulatory deferral and variance account being requested for disposition.

Response

Hydro One is requesting recovery/refund of regulatory deferral accounts through the "usual practice" of rate riders. The details of the amounts to be recovered/refunded through the riders is summarized in Exhibit F1-2-1, Table 1. Hydro One is proposing to refund the net balance of $48.7M over a four-year period (ie. $12.2M per year, as shown in the response to H1-122).

Exhibit G1, Tab 5, Schedule 1, Table 1, provides the allocators for each of the regulatory deferral and variance accounts being requested for disposition and the resultant rate riders.

Hydro One is not including the recovery/refund of regulatory deferral accounts in base revenue requirement. In this exhibit, the term revenue requirement is used to mean the sum of base revenue requirement plus riders.

Ontario Energy Board (Board Staff) INTERROGATORY #119 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1
Usual practice in the electricity sector is to use audited numbers for the last fiscal years as the basis for balances in the deferral and variance accounts for disposition, with interest forecasted up to the start of the new rate year.

a. Please provide the regulatory precedent for principal transactions being forecasted beyond December 31, 2006 for accounts requested for disposition.
b. Please recalculate the appropriate rate rider schedules using the December 31, 2006 balances with interest forecasted to April 30, 2008.

Response

a. The regulatory precedent can be found in RP-2005-0020 (EB-2005-0378), 2006 Electricity Distribution Rates. In the Hydro One Distribution submitted evidence, audited financial statements were provided up to December 31, 2004 and Regulatory Asset balances were projected to April 30, 2006. Those projected balances were approved by the Board on April 12, 2006 (subject to interest rate changes).

b. See Attachment A for recalculated rate rider schedule.

Regulatory Asset Recovery 2007 Scenario

Stats for Allocation			Formula	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST	
Cust	1,177,552		A	162,058	376,430	364,938	155,177	97,005	7,015	12,744	1,429	-	-	84	673	
GWh	38,411		B	1,494	4,407	5,624	707	2,299	3,237	424	831	121	22	3.4	19,240	
GWh excl WMP	24,267		C	1,494	4,407	5,624	707	2,299	3,237	424	831	121	22	3.4	5,096	
GWh excl WMP & excl RRP	9,167		D						3,237		831			3	5,096	
Billing kWs	56,293,509		E						11,019,445		2,203,297			48,843	43,021,924	
Dx Rev excl Riders [$M]	1,024		F	53.9	186.5	392.6	74.8	113.9	105.5	11.6	15.7	4.8	0.9	0.6	63.4	
OMA	100%		G	6.76%	24.04%	38.79%	8.06%	10.48%	7.19%	0.93%	0.96%	0.64%	0.18%	0.01%	1.96%	
NFA	100%		H	5.78%	21.57%	35.38%	7.62%	10.52%	12.37%	0.90%	2.13%	0.89%	0.19%	0.01%	2.64%	
Balances	$ 1000s	**Allocator**														
Provincial Benefit	8,308	GWh excl WMP & RRP	I	$ -	$ -	$ -	$ -	$ -	$ 2,933.9	$ -	$ 752.9	$ -	$ -	$ 3.1	$ 4,618.2	
RSVA Wholesale Market Service Charges	(25,354)	GWh excl WMP	J	$ (1,561.1)	$ (4,604.9)	$ (5,876.5)	$ (738.4)	$ (2,402.3)	$ (3,382.4)	$ (443.2)	$ (868.0)	$ (126.0)	$ (23.4)	$ (3.5)	$ (5,324.3)	
RSVA Tx Network	8,026	GWh	K	$ 312.2	$ 921.0	$ 1,175.3	$ 147.7	$ 480.5	$ 676.5	$ 88.6	$ 173.6	$ 25.2	$ 4.7	$ 0.7	$ 4,020.4	
RSVA Tx Connection	5,763	GWh	L	$ 224.2	$ 661.2	$ 843.8	$ 106.0	$ 345.0	$ 485.7	$ 63.6	$ 124.6	$ 18.1	$ 3.4	$ 0.5	$ 2,886.6	
RSVA LV Wheeling	901	GWh	M	$ 35.1	$ 103.4	$ 132.0	$ 16.6	$ 54.0	$ 76.0	$ 10.0	$ 19.5	$ 2.8	$ 0.5	$ 0.1	$ 451.5	
OEB Costs	(930)	OMA	N	$ (62.8)	$ (223.5)	$ (360.6)	$ (74.9)	$ (97.4)	$ (66.8)	$ (8.6)	$ (9.0)	$ (5.9)	$ (1.7)	$ (0.1)	$ (18.2)	
Tax Change	(2,991)	NFA	O	$ (173.0)	$ (645.1)	$ (1,058.4)	$ (227.9)	$ (314.6)	$ (370.0)	$ (26.9)	$ (63.8)	$ (26.7)	$ (5.7)	$ (0.2)	$ (78.9)	
Smart Meter Minimum Functionality to May 31, 2007	3,874	Cust #	P	$ 533.1	$ 1,238.3	$ 1,200.5	$ 510.5	$ 319.1	$ 23.1	$ 41.9	$ 4.7	$ -	$ -	$ 0.3	$ 2.2	
Smart Meter Costs Exceeding Minimum Functionality	681	Cust #	Q	$ 93.7	$ 217.8	$ 211.1	$ 89.8	$ 56.1	$ 4.1	$ 7.4	$ 0.8	$ -	$ -	$ 0.0	$ 0.4	
Smart Meter Minimum Functionality after May 31, 2007	-	Cust #	R	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Total Regulatory Assets for Approval	$ (1,722)															
	$ (1,721.5)		S	$ (598.6)	$ (2,331.9)	$ (3,732.8)	$ (170.6)	$ (1,559.8)	$ 379.9	$ (267.2)	$ 135.4	$ (112.5)	$ (22.3)	$ 0.9	$ 6,557.9	
Assuming a 4 year recovery	$ (430.4)		T = R/4	$ (149.7)	$ (583.0)	$ (933.2)	$ (42.7)	$ (389.9)	$ 95.0	$ (66.8)	$ 33.9	$ (28.1)	$ (5.6)	$ 0.2	$ 1,639.5	
	Rider 3	c/kWh	T/B	(0.010)	(0.013)	(0.017)	(0.006)	(0.017)	0.003	(0.016)	0.004	(0.023)	(0.025)	0.007	0.009	
	$ (1,721.5)	$/kW	T/E						0.009		0.015			0.005	0.038	
	Rider 3 Filed	c/kWh		(0.025)	(0.037)	(0.049)	0.017	(0.057)	(0.074)	(0.059)	(0.072)	(0.080)	(0.082)	(0.061)	(0.015)	
	$ (12,170.0)	$/kW		-	-	-	-	-	(0.217)	-	(0.273)	-	-	(0.042)	(0.067)	

Ontario Energy Board (Board Staff) INTERROGATORY #120 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1
Tables 5, 6 and 7 at Exhibit F1/Tab 1/Schedule 1 relate to "Net Revenue Requirement to be Recovered".

a. Please provide in one consolidated table the Net Revenue Requirement to be Recovered for minimum functionality covered in table 5 and 7 in accordance with Appendix E of the EB-2007-0063 Decision on Smart Meters. Please also include in this table the smart metering capital that the return on equity and interest expense is being calculated from as well as the capital structure being relied on in these calculations.
b. Is Hydro One currently using accounts 1555 and 1556?
c. Please identify any deviations from the Board's guidance with respect to these accounts.
d. Is Hydro One planning to continue these accounts after April 30th, 2008?
e. Is Hydro One planning on continuing to charge the rate rider associated with Smart Metering. If so, why?
f. Please provide a detailed calculation of revenue requirement for Table 6, Smart Meter Exceeding Minimum Functionality Under-Recovery

Response

a. The attached (Attachment A) spreadsheet provides the calculation of net revenue requirement for each of the three smart meter regulatory assets, consistent with the amounts shown in Tables 5, 6, and 7 in Exhibit F1, Tab 1, Schedule 1. The spreadsheet contains the calculation of forecast annual rate base, annual revenue requirement, and cumulative net revenue requirement as at year-end 2006, year-end 2007, and April 30, 2008 for each of the smart meter regulatory assets.

b. Yes

c. Hydro One is in compliance with Board guidance for use of these accounts.

d. Yes, except that we are not expecting to use the interim recoveries account after the date of implementation of the 2008 Distribution rate change.

e. No, Hydro One will stop recovery of the rate rider related to recovery of interim smart meter costs effective the date of the implementation of the 2008 Distribution rate change.

f. See response to part a.

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - up to May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Return on rate base				
Opening fixed assets:				
Gross assets	0.0	2.2	21.1	
Less: Accumulated depreciation	0.0	(0.1)	(0.9)	
Net fixed assets	0.0	2.1	20.3	
Closing fixed assets:				
Gross assets	2.2	21.1	21.1	
Less: Accumulated depreciation	(0.1)	(0.9)	(1.3)	
Net fixed assets	2.1	20.3	19.8	
Average fixed assets	1.1	11.2	20.0	
Working capital	0.9	0.4	0.0	
Total rate base	1.9	11.6	20.0	
Cost of debt	0.1	0.4	0.2	Pro-rated for number of months in period
Return on equity	0.1	0.4	0.2	Pro-rated for number of months in period
Return on rate base	0.1	0.8	0.5	
Revenue requirement before PILs				
OM&A	5.8	2.6	0.0	Pro-rated for number of months in period
Depreciation	0.1	0.8	0.5	Pro-rated for number of months in period
Return on rate base	0.1	0.8	0.5	
Revenue requirement before PILs	6.0	4.1	0.9	
PILs				
Revenue requirement before PILs	6.0	4.1	0.9	
Less: OM&A	(5.8)	(2.6)	0.0	
Less: Depreciation	(0.1)	(0.8)	(0.5)	
Less: Interest	(0.1)	(0.4)	(0.2)	
Income for PILs purposes	0.1	0.4	0.2	
Add depreciation	0.1	0.8	0.5	
Deduct CCA	(0.1)	(0.9)	(0.5)	Pro-rated for number of months in period
Taxable income for PILs purposes	0.1	0.3	0.2	
PILs before gross up	0.0	0.1	0.1	
Grossed up PILs	0.0	0.1	0.1	
Revenue requirement				
Revenue requirement before PILs	6.0	4.1	0.9	
Grossed up PILs	0.0	0.1	0.1	
Revenue requirement	6.0	4.3	1.0	
Under-recovery				
Revenue requirement	6.0	4.3	1.0	
Less: Revenue earned	(2.5)	(2.3)	0.0	
	3.6	2.0	1.0	
Carrying charge	0.1	0.2	0.1	Pro-rated for number of months in period
Under-recovery	3.6	2.2	1.1	
Cumulative balance	3.6	5.8	6.9	

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - up to May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Inputs				
OM&A	5.8	2.6	0.0	Per OEB decision (August 8, 2007)
Capital (I/S additions)	2.2	18.9	0.0	Per OEB decision (August 8, 2007)
Interim revenue	2.5	2.3	0.0	
Number of months in period	12	12	4	
Working capital (% of OM&A)	15%	15%	15%	
Depreciation life (years)	15	15	15	
CCA rate (%)	8%	8%	8%	
Cost of debt (%)	5.93%	5.93%	5.93%	Weighted average cost of debt per 2006 Dx filing
Cost of equity (%)	8.65%	8.65%	8.65%	Weighted average cost of equity per 2006 Dx filing
Deemed equity (%)	40%	40%	40%	Per 2006 Dx filing
Tax rate (%)	36.12%	36.12%	34.50%	
Interest rate on reg assets	4.59%	4.64%	4.74%	
Detailed calculations				
Depreciation				
Opening gross fixed assets	0.0	2.2	21.1	
Closing gross fixed assets	2.2	21.1	21.1	
Average gross fixed assets	1.1	11.7	21.1	
Depreciation	0.1	0.8	1.4	
CCA				
Opening UCC	0.0	2.1	20.1	
Plus: Additions	2.2	18.9	0.0	
Less: CCA	(0.1)	(0.9)	(1.6)	
Closing UCC	2.1	20.1	18.5	
UCC for CCA	1.1	11.6	20.1	
CCA	0.1	0.9	1.6	

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - post May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Return on rate base				
Opening fixed assets:				
Gross assets	0.0	0.3	77.5	
Less: Accumulated depreciation	0.0	(0.0)	(2.6)	
Net fixed assets	0.0	0.3	74.9	
Closing fixed assets:				
Gross assets	0.3	77.5	209.3	
Less: Accumulated depreciation	(0.0)	(2.6)	(5.8)	
Net fixed assets	0.3	74.9	203.5	
Average fixed assets	0.1	37.6	139.2	
Working capital	0.0	0.8	1.3	
Total rate base	0.1	38.4	140.5	
Cost of debt	0.0	1.4	1.7	Pro-rated for number of months in period
Return on equity	0.0	1.3	1.6	Pro-rated for number of months in period
Return on rate base	0.0	2.7	3.3	
Revenue requirement before PILs				
OM&A	0.0	5.5	2.9	Pro-rated for number of months in period
Depreciation	0.0	2.6	3.2	Pro-rated for number of months in period
Return on rate base	0.0	2.7	3.3	
Revenue requirement before PILs	0.0	10.7	9.4	
PILs				
Revenue requirement before PILs	0.0	10.7	9.4	
Less: OM&A	0.0	(5.5)	(2.9)	
Less: Depreciation	(0.0)	(2.6)	(3.2)	
Less: Interest	(0.0)	(1.4)	(1.7)	
Income for PILs purposes	0.0	1.3	1.6	
Add depreciation	0.0	2.6	3.2	
Deduct CCA	(0.0)	(3.1)	(3.7)	Pro-rated for number of months in period
Taxable income for PILs purposes	0.0	0.8	1.1	
PILs before gross up	0.0	0.3	0.4	
Grossed up PILs	0.0	0.5	0.6	
Revenue requirement				
Revenue requirement before PILs	0.0	10.7	9.4	
Grossed up PILs	0.0	0.5	0.6	
Revenue requirement	0.0	11.2	10.0	
Under-recovery				
Revenue requirement	0.0	11.2	10.0	
Less: Revenue earned	0.0	(7.6)	(4.4)	
	0.0	3.6	5.6	
Carrying charge	0.0	0.1	0.1	Pro-rated for number of months in period
Under-recovery	0.0	3.7	5.7	
Cumulative balance	0.0	3.7	9.4	

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - post May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Inputs				
OM&A	0.0	5.5	8.8	
Capital (I/S additions)	0.3	77.2	131.8	
Interim revenue	0.0	7.6	4.4	
Number of months in period	12	12	4	
Working capital (% of OM&A)	15%	15%	15%	
Depreciation life (years)	15	15	15	
CCA rate (%)	8%	8%	8%	
Cost of debt (%)	5.93%	5.93%	5.93%	Weighted average cost of debt per 2006 Dx filing
Cost of equity (%)	8.65%	8.65%	8.65%	Weighted average cost of equity per 2006 Dx filing
Deemed equity (%)	40%	40%	40%	Per 2006 Dx filing
Tax rate (%)	36.12%	36.12%	34.50%	
Interest rate on reg assets	4.59%	4.64%	4.74%	
Detailed calculations				
Depreciation				
Opening gross fixed assets	0.0	0.3	77.5	
Closing gross fixed assets	0.3	77.5	209.3	
Average gross fixed assets	0.2	38.9	143.4	
Depreciation	0.0	2.6	9.6	
CCA				
Opening UCC	0.0	0.3	74.3	
Plus: Additions	0.3	77.2	131.8	
Less: CCA	(0.0)	(3.1)	(11.2)	
Closing UCC	0.3	74.3	194.9	
UCC for CCA	0.2	38.9	140.3	
CCA	0.0	3.1	11.2	

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Exceed Minimum Functionality

($ millions)	2006	2007	Jan-Apr 2008	Comments
Return on rate base				
Opening fixed assets:				
Gross assets	0.0	0.6	24.6	
Less: Accumulated depreciation	0.0	(0.0)	(0.9)	
Net fixed assets	0.0	0.6	23.8	
Closing fixed assets:				
Gross assets	0.6	24.6	57.6	
Less: Accumulated depreciation	(0.0)	(0.9)	(1.8)	
Net fixed assets	0.6	23.8	55.8	
Average fixed assets	0.3	12.2	39.8	
Working capital	0.1	0.1	0.1	
Total rate base	0.4	12.3	39.9	
Cost of debt	0.0	0.4	0.5	Pro-rated for number of months in period
Return on equity	0.0	0.4	0.5	Pro-rated for number of months in period
Return on rate base	0.0	0.9	0.9	
Revenue requirement before PILs				
OM&A	0.6	0.8	0.3	Pro-rated for number of months in period
Depreciation	0.0	0.8	0.9	Pro-rated for number of months in period
Return on rate base	0.0	0.9	0.9	
Revenue requirement before PILs	0.6	2.5	2.1	
PILs				
Revenue requirement before PILs	0.6	2.5	2.1	
Less: OM&A	(0.6)	(0.8)	(0.3)	
Less: Depreciation	(0.0)	(0.8)	(0.9)	
Less: Interest	(0.0)	(0.4)	(0.5)	
Income for PILs purposes	0.0	0.4	0.5	
Add depreciation	0.0	0.8	0.9	
Deduct CCA	(0.0)	(1.0)	(1.1)	Pro-rated for number of months in period
Taxable income for PILs purposes	0.0	0.3	0.3	
PILs before gross up	0.0	0.1	0.1	
Grossed up PILs	0.0	0.1	0.2	
Revenue requirement				
Revenue requirement before PILs	0.6	2.5	2.1	
Grossed up PILs	0.0	0.1	0.2	
Revenue requirement	0.6	2.6	2.3	
Under-recovery				
Revenue requirement	0.6	2.6	2.3	
Less: Revenue earned	0.0	0.0	0.0	
	0.6	2.6	2.3	
Carrying charge	0.0	0.1	0.1	Pro-rated for number of months in period
Under-recovery	0.6	2.7	2.4	
Cumulative balance	0.6	3.4	5.7	

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Exceed Minimum Functionality

($ millions)	2006	2007	Jan-Apr 2008	Comments
Inputs				
OM&A	0.6	0.8	0.9	
Capital (I/S additions)	0.6	24.0	33.0	
Interim revenue	0.0	0.0	0.0	
Number of months in period	12	12	4	
Working capital (% of OM&A)	15%	15%	15%	
Depreciation life (years)	15	15	15	
CCA rate (%)	8%	8%	8%	
Cost of debt (%)	5.93%	5.93%	5.93%	Weighted average cost of debt per 2006 Dx filing
Cost of equity (%)	8.65%	8.65%	8.65%	Weighted average cost of equity per 2006 Dx filing
Deemed equity (%)	40%	40%	40%	Per 2006 Dx filing
Tax rate (%)	36.12%	36.12%	34.50%	
Interest rate on reg assets	4.59%	4.64%	4.74%	
Detailed calculations				
Depreciation				
Opening gross fixed assets	0.0	0.6	24.6	
Closing gross fixed assets	0.6	24.6	57.6	
Average gross fixed assets	0.3	12.6	41.1	
Depreciation	0.0	0.8	2.7	
CCA				
Opening UCC	0.0	0.6	23.6	
Plus: Additions	0.6	24.0	33.0	
Less: CCA	(0.0)	(1.0)	(3.2)	
Closing UCC	0.6	23.6	53.4	
UCC for CCA	0.3	12.6	40.1	
CCA	0.0	1.0	3.2	

Ontario Energy Board (Board Staff) INTERROGATORY #121 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1
Hydro One is requesting to dispose of the RSVA Provincial Benefit account.

a. Please confirm that this refers to account 1588 sub-account Global Adjustment according to the USoA. If it is not, then please identify in which account this is being tracked.
b. Is Hydro One proposing to clear only the sub-account and not clear the entire balance in account 1588 RSVA Power?

Response

a. Yes, the RSVA Provincial Benefit account that Hydro One Distribution is requesting disposition of refers to the account 1588 sub-account Global Adjustment.

b. Yes, Hydro One Distribution is proposing to clear only the sub-account. Hydro One Distribution does not have RSVA for Power.

Ontario Energy Board (Board Staff) INTERROGATORY #122 List 1

Interrogatory

Ref: ExF/Tab1/Sch6/ Issue 6.1
Hydro One is proposing to refund the deferral and variance accounts to customers over a period of 4 years.

a. What is the regulatory precedent for having a greater than three year period for the rate riders, seeing as the company may be rebased in 2011?
b. Please provide a schedule identifying the rate riders associated with the disposition of the deferral and variance accounts over a one, two and three year periods. Please show all relevant calculations.

Response

a. Hydro One has in the past recovered variance account balances over 4 years as an impact mitigation measure, as noted below:

   1) Rider # 1, approved as part of Proceeding RP-2004-0117/RP-2004-0118/EB-2004-0371 covers the period April 1, 2005 to April 30, 2008.

   2) Rider # 2 approved as part of Proceeding RP-2005-0020/EB-2005-0378 covers the period May 2006 to April 2010.

b. Please see Attachment A.

Regulatory Asset Recovery 2007

Stats for Allocation			Formula	UR	R1	R2	Seasonal	GSe	GSd	UGe
Cust	1,177,552		A	162,058	376,430	364,938	155,177	97,005	7,015	12,744
GWh	38,411		B	1,494	4,407	5,624	707	2,299	3,237	424
GWh excl WMP	24,267		C	1,494	4,407	5,624	707	2,299	3,237	424
Billing kWs	56,293,509		D						11,019,445	
Dx Rev excl Riders [$M]	1,024		E	53.9	186.5	392.6	74.8	113.9	105.5	11.6
OMA	100%		F	6.76%	24.04%	38.79%	8.06%	10.48%	7.19%	0.93%
NFA	100%		G	5.78%	21.57%	35.38%	7.62%	10.52%	12.37%	0.90%

Balances	$ 1000s	Allocator								
RSVA Wholesale Mkt SrChg	(72,590)	GWh excl WMP	H	$ (4,469.60)	$ (13,184.11)	$ (16,824.68)	$ (2,114.04)	$ (6,878.01)	$ (9,684.03)	$ (1,268.81)
RSVA Tx Network	1,430	GWh	I	$ 55.63	$ 164.08	$ 209.39	$ 26.31	$ 85.60	$ 120.52	$ 15.79
RSVA Tx Connection	2,540	GWh	J	$ 98.80	$ 291.45	$ 371.93	$ 46.73	$ 152.05	$ 214.07	$ 28.05
RSVA LV Wheeling	3,840	GWh	K	$ 149.37	$ 440.61	$ 562.28	$ 70.65	$ 229.86	$ 323.64	$ 42.40
OEB Costs	$ (900)	OMA	L	$ (60.83)	$ (216.40)	$ (349.11)	$ (72.56)	$ (94.34)	$ (64.69)	$ (8.34)
Tax Rate Change	$ (5,000)	NFA	M	$ (289.15)	$ (1,078.38)	$ (1,769.17)	$ (380.87)	$ (525.84)	$ (618.52)	$ (44.99)
Smart Meter Minimum Functionality to May 31, 2007	$ 6,900	Cust #	N	$ 949.60	$ 2,205.73	$ 2,138.39	$ 909.28	$ 568.41	$ 41.10	$ 74.68
Smart Meter Costs Exceeding Minimum Functionality	$ 5,700	Cust #	O	$ 784.45	$ 1,822.13	$ 1,766.50	$ 751.14	$ 469.56	$ 33.96	$ 61.69
Smart Meter Minimum Functionality after May 31, 2007	$ 9,400	Cust #	P	$ 1,293.66	$ 3,004.91	$ 2,913.18	$ 1,238.73	$ 774.36	$ 56.00	$ 101.73
Total Regulatory Assets for Approval	$ (48,680)									
	$ (48,680.0)		Q	$ (1,488.1)	$ (6,550.0)	$ (10,981.3)	$ 475.4	$ (5,218.4)	$ (9,577.9)	$ (997.8)
Assuming a 4 year recovery	$ (12,170.0)		R = Q/4	$ (372.0)	$ (1,637.5)	$ (2,745.3)	$ 118.8	$ (1,304.6)	$ (2,394.5)	$ (249.4)
	Rider 3	c/kWh	R/B	(0.02)	(0.04)	(0.05)	0.02	(0.06)	(0.07)	(0.06)
		$/kW	R/D						(0.22)	

Alternative Recovery Periods

Recovery Period [Years]										
1	$ (48,680.00)		S=Q/1	$ (1,488.07)	$ (6,549.97)	$ (10,981.28)	$ 475.37	$ (5,218.36)	$ (9,577.94)	$ (997.79)
2	$ (24,340.00)		T=Q/2	$ (744.03)	$ (3,274.99)	$ (5,490.64)	$ 237.68	$ (2,609.18)	$ (4,788.97)	$ (498.90)
3	$ (16,226.67)		U=Q/3	$ (496.02)	$ (2,183.32)	$ (3,660.43)	$ 158.46	$ (1,739.45)	$ (3,192.65)	$ (332.60)
Rate Rider 3	1 Year	c/kWh	S/B	(0.10)	(0.15)	(0.20)	0.07	(0.23)	(0.30)	(0.24)
		$/kW	S/D						(0.87)	
	2 Year	c/kWh	T/B	(0.05)	(0.07)	(0.10)	0.03	(0.11)	(0.15)	(0.12)
		$/kW	T/D						(0.43)	
	3 Year	c/kWh	U/B	(0.03)	(0.05)	(0.07)	0.02	(0.08)	(0.10)	(0.08)
		$/kW	U/D						(0.29)	

Regulatory Asset Recovery 2007

Stats for Allocation			Formula	UGd	St Lgt	Sen Lgt	Dgen	ST
Cust	1,177,552		A	1,429	-	-	84	673
GWh	38,411		B	831	121	22	3.4	19,240
GWh excl WMP	24,267		C	831	121	22	3.4	5,096
Billing kWs	56,293,509		D	2,203,297			48,843	43,021,924
Dx Rev excl Riders [$M]	1,024		E	15.7	4.8	0.9	0.6	63.4
OMA	100%		F	0.96%	0.64%	0.18%	0.01%	1.96%
NFA	100%		G	2.13%	0.89%	0.19%	0.01%	2.64%

Balances	$ 1000s	Allocator						
RSVA Wholesale Mkt SrChg	(72,590)	GWh excl WMP	H	$ (2,485.24)	$ (360.75)	$ (67.06)	$ (10.14)	$ (15,243.54)
RSVA Tx Network	1,430	GWh	I	$ 30.93	$ 4.49	$ 0.83	$ 0.13	$ 716.30
RSVA Tx Connection	2,540	GWh	J	$ 54.94	$ 7.97	$ 1.48	$ 0.22	$ 1,272.30
RSVA LV Wheeling	3,840	GWh	K	$ 83.06	$ 12.06	$ 2.24	$ 0.34	$ 1,923.48
OEB Costs	$ (900)	OMA	L	$ (8.68)	$ (5.74)	$ (1.62)	$ (0.05)	$ (17.64)
Tax Rate Change	$ (5,000)	NFA	M	$ (106.59)	$ (44.67)	$ (9.60)	$ (0.31)	$ (131.91)
Smart Meter Minimum Functionality to May 31, 2007	$ 6,900	Cust #	N	$ 8.37	$ -	$ -	$ 0.49	$ 3.94
Smart Meter Costs Exceeding Minimum Functionality	$ 5,700	Cust #	O	$ 6.92	$ -	$ -	$ 0.40	$ 3.26
Smart Meter Minimum Functionality after May 31, 2007	$ 9,400	Cust #	P	$ 11.40	$ -	$ -	$ 0.67	$ 5.37
Total Regulatory Assets for Approval	$ (48,680)							
	$ (48,680.0)		Q	$ (2,404.9)	$ (386.6)	$ (73.7)	$ (8.2)	$ (11,468.4)
Assuming a 4 year recovery	$ (12,170.0)		R = Q/4	$ (601.2)	$ (96.7)	$ (18.4)	$ (2.1)	$ (2,867.1)
	Rider 3	c/kWh	R/B	(0.07)	(0.08)	(0.08)	(0.06)	(0.01)
		$/kW	R/D	(0.27)			(0.04)	(0.07)

Alternative Recovery Periods

Recovery Period [Years]								
1	$ (48,680.00)		S=Q/1	$ (2,404.89)	$ (386.64)	$ (73.72)	$ (8.25)	$ (11,468.44)
2	$ (24,340.00)		T=Q/2	$ (1,202.45)	$ (193.32)	$ (36.86)	$ (4.12)	$ (5,734.22)
3	$ (16,226.67)		U=Q/3	$ (801.63)	$ (128.88)	$ (24.57)	$ (2.75)	$ (3,822.81)
Rate Rider 3	1 Year	c/kWh	S/B	(0.29)	(0.32)	(0.33)	(0.24)	(0.06)
		$/kW	S/D	(1.09)			(0.17)	(0.27)
	2 Year	c/kWh	T/B	(0.14)	(0.16)	(0.16)	(0.12)	(0.03)
		$/kW	T/D	(0.55)			(0.08)	(0.13)
	3 Year	c/kWh	U/B	(0.10)	(0.11)	(0.11)	(0.08)	(0.02)
		$/kW	U/D	(0.36)			(0.06)	(0.09)

Ontario Energy Board (Board Staff) INTERROGATORY #123 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2
Hydro One is requesting a new deferral and variance account for the Pension Cost Differential.

a. Please provide the justification for this request, particularly identifying, when the actuarial valuation was prepared as at December 31, 2006, and when it was filed with FSCO and included in forecasted rates.
b. What is the proposed methodology for recording pension costs into this account (cash or accrual)? If Hydro One is proposing a change to the accrual method, is the company also proposing to record the difference between the expense embedded in rates and the accrual expense as per the audited financial statements, into this account?
c. In Hydro One's view what would the impact of its proposal be on the IRM 3 mechanism?
d. Can Hydro One identify any regulatory precedent in support of its proposal?
e. Please provide an estimate of the variance to be recorded in this account, if any.
f. What account number does Hydro One propose to use in the USoA?
g. What are the journal entries to be recorded?
h. When does Hydro One plan to ask for its disposition?
i. How does Hydro One plan to allocate this amount by rate class?
j. What new or additional information is available since the December 18, 2007 filing of this application that would improve the Board's ability to make a decision on this request?

Response

a. The actuarial valuation report as at December 31, 2006 was prepared during 2007, completed in August 2007 and filed with FSCO in September 2007. The actuarial report sets out the minimum funding requirements for the company that includes both a variable component as a function of base pensionable earnings, plus a fixed component for the deficiency in the plan. Given there is a variable component to the funding amount, there could be a difference between estimated pension costs being sought for recovery and actual pension costs. Since the actuarial valuation was filed with FSCO subsequent to the EB-2007-0681 evidence being filed with the OEB on August 15, 2007, the forecast amount of pension contribution was based on an estimate, rather than the final valuation. Thus, Hydro One Distribution is requesting a deferral account.

b. The Board has allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). Consistent with its prior Distribution rate application (RP-2005-0020/EB-2005-0378), Hydro One does not use the accrual method for rate setting purposes nor in its audited financial statements. Pension costs continue to be recorded on a cash basis and as such, there is no change from this basis.

c. It is premature to speculate as the IRM3 mechanism has not yet been established.

d. On July 14, 2004 the Board issued its Decision and Order (RP-2004-0180) approving the creation of a deferral account for Hydro One Distribution to record the pension costs and related interest. A similar account was approved as part of Hydro One Transmission's rate application (EB-2006-0501).

e. The estimated amount to be recorded in the variance account for 2008 is approximately $130 thousand (liability) per month.

f. Hydro One would use Account 1508 Other Regulatory Assets; Sub Account Pension Contributions

g. Where pension costs recovered through rates are higher than actual pension costs incurred, the entry will be:

Dr. Revenue
Cr. Pension Deferral Account (liability)

Where pension costs recovered are less than actual pension costs incurred, the opposite entry would apply.

h. Hydro One would ask for disposition of this account as part of the next Cost of Service hearing.

i. This amount would be allocated to all rate classes. Consistent with the proposed allocator in Regulatory Rate Rider #3 for both OM&A costs, Exhibit G1, Tab 5, Schedule 1, Page 2, lines 13 to 16, OM&A costs would be the allocator used by Hydro One to allocate the amount amongst customer classes.

j. The rate application in this filing was based on an estimate of about $104 million for pension costs in 2008. The actual pension costs for 2007 were about $95 million. While the actual pension contribution is expected to be higher in 2008 as a result of higher base pensionable earnings, the expectation is that the deferral account will be in an over-recovery (liability) position. See response to (e) above.

Ontario Energy Board (Board Staff) INTERROGATORY #124 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2
Hydro One is requesting for a new deferral and variance account related to the OEB Cost Differential.

a. What is the regulatory precedent for the collection of each of the identified costs proposed to be included in this deferral account?
b. What is the justification for this account?
c. What account number does Hydro One propose to use in the USoA?
d. What are the journal entries to be recorded?
e. If the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?
f. What new or additional information is available that would improve the Board's ability to make a decision on this request?

Response

a. The regulatory precedent can be found in a letter from the Board dated December 20, 2004 to electricity distributors. In that letter the Board authorized the establishment of a deferral account to record OEB cost assessments that may not be included in rates. Hydro One Distribution established the deferral account pursuant to the Board letter and received approval for recovery of costs recorded in the deferral account in RP-2005-0020 (EB-2005-0378) Hydro One Networks Inc., Electricity Distribution Rates 2006. In that same decision, the Board approved Hydro One Distribution's request for establishment of a new variance account for the OEB Cost Assessment Differential.

b. Hydro One Distribution budgets for costs associated with the annual OEB assessment, intervenor awards, and OEB-initiated studies. However the actual amounts of these payments are subject to variability and are outside of the Company's control. As such, it is appropriate that any differences between budgeted and actual costs be tracked and recovered from or paid back to customers.

c. Hydro One Distribution proposes to use USofA 1508.

d. The journal entry will be as follows, if the amount of the payment to be made is greater than the amount approved in rates:

Debit: Regulatory Asset OEB Cost Assessment (Balance Sheet Account),
Credit: OM&A Program Account recording the payment

The amount of the journal will be calculated as the difference between the actual annual OEB Cost Assessments, intervenor cost awards, and costs associated with OEB-initiated studies and the amount for these expenditures approved by the OEB as part of 2008 Distribution Rates.

e. Costs or fees would only be booked to this account once they are known.

f. The support and precedent for this request is provided in the Exhibit F1, Tab 3, Schedule 1 and in the response to (a) above.

Ontario Energy Board (Board Staff) INTERROGATORY #125 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2
Hydro One is requesting for a new deferral and variance account for the Bill Impact Mitigation.

a. What is the regulatory precedent for the collection of the difference between the Hydro One requested revenue requirement and the distribution rates from the application of the Cost Allocation for Electricity Distributors report in this proposed deferral account?
b. What is the justification for this account?
c. What account number does Hydro One propose to use in the USoA?
d. What are the journal entries to be recorded?
e. Please provide a continuity schedule of the incentive rate years outlining expected transactions into this variance account if approved.
f. What new or additional information is available that would improve the Board's ability to make a decision on this request?

Response

a. Please see Exhibit F1, Tab 3, Schedule 1, page 2, lines 11 to 17 for regulatory precedent.

b. The justification is to limit bill impacts to customers to a maximum of 10% on total bill.

c. Hydro One is proposing to use account 1508.

d. The journal entries are Debit to Regulatory Assets / Credit to Revenue.

e. Hydro One is expecting that $2.5M would be added to this account every year, beginning May 1, 2008. An illustrative continuity schedule for the period from May 2008 to April 2011 is provided in the table below:

$ millions	May 2008	Dec 2009	Dec 2010	Dec 2011	Apr 2011
Principal	0.0	1.7	4.2	6.7	7.5
Interest	0.0	0.0	0.2	0.4	0.6
Total	**0.0**	**1.7**	**4.3**	**7.1**	**8.1**

f. There is no new information.

Ontario Energy Board (Board Staff) INTERROGATORY #126List 1

Interrogatory

Ref: Exhibit C1 /Tab 2 /Schedule 2/ Issue 8.1
On page 27, Hydro One indicates that "minimum functionality" OM&A smart meter costs for 2007 and 2008 are $6.2 million and $5.8 million respectively.

a. Does the 2007 amount of $6.2 million for OM&A smart meter expenditures represent actual spending? Please confirm.
b. Is the amount of $6.2 million for 2007 consistent with the amount of $8.366 million for 2006 and up to May 31, 2007 which was approved by the Board in EB-2007-0063? If not, please provide the 2007 amount which would have been consistent with the $8.366 million for 2006 and up to May 31, 2007 and explain fully the reason for the difference. Please provide the breakdown of the $8.366 million smart meter OM&A cost, which was approved by the Board in the combined proceeding, for each of 2006 and for the period January 1 to May 31, 2007.

On page 27, Hydro One states that the following work is included as part of "minimum functionality":
° Maintaining and operating hardware, software and software licences associated with the advanced metering control computer (AMCC);
° Telecommunication charges associated with operating the local area networks (LANs) and wide area network (WAN); and
° Maintaining and operating smart meters and network devices that have been placed into service.

c. Please provide a breakdown of the proposed $6.2 million and $5.8 million "minimum functionality" smart meter OM&A costs for 2007 and 2008 for the above mentioned three work categories. Please also provide, for each work category, the costs for labour, material, contracts, and other identifiable categories.

On page 27, Hydro One states "Incremental functionality activities associated with effective use of the smart meters to provide time-differentiated billing to customers and provide Hydro One the ability to leverage its Advanced Metering Infrastructure (AMI) system for other business benefits, which account for $0.0 million and $3.9 million in 2007 and 2008 respectively, include the following work:
° Managing, developing and implementing business process re-design (e.g. manual to automated meter reading for on-cycle and off-cycle reads), change management (including staff training) and customer communication related work;
° Responding to a higher number of customer inquiries as a result of pre- and post-installation of smart meters on customer premises; and

° Maintaining the changes required to the CIS system (new processes, workflow and tariffs) and the systems and interfaces necessary to integrate to the AMCC and the IESO's meter data management and meter data repository (MDM/R)."

d. Please provide a breakdown of the proposed $3.9 million "incremental functionality" OM&A smart meter cost for 2008 for the above mentioned three work categories. Please also provide, for each work category, the costs for labour, material, contract, and other identifiable categories.
e. Please indicate whether the above mentioned activities will result in the hiring of extra staff. If so, please provide the FTE and the estimated cost for the hiring of extra human resources for each category.

On page 28, Hydro One states: "Spending on smart meter program contributes to lower costs in other program areas. In addition to the estimated savings of $2.8 million in customer retail meter maintenance costs resulting from reduced meter testing and replacement due to the Measurement Canada dispensation, as discussed in Section 2.3.1 of this exhibit, there are also estimated savings of $1.4 million in 2008 as a result of reduction in the number of manual meter reads related to the smart meter program, as discussed in Section 2.1.2 of Exhibit C1, Tab 2, Schedule 5."

And on page 25, under Section 2.3.1, Hydro One states: "To avoid inefficiencies which would result from the testing and verification of installed meters, followed by their near term replacement by smart meters, Hydro One Distribution received a dispensation in 2006 from Measurement Canada which allows meters coming due for verification from 2008 through 2010 to remain in place without verification."

f. Please indicate whether the estimated savings of $2.8 million in customer retail meter maintenance costs resulting from reduced meter testing and replacement due to the Measurement Canada dispensation applies only to test year 2008. If not, please provide the amounts of savings for each year from 2008 through 2010.
g. Please explain whether the reduction in the number of manual meter reads related to the smart meter program will result in the reduction of human resources and/or contract costs in the area of meter reading. If so, please indicate the number of reductions in employees and/or contract costs as a result of the reduction in the number of the manual reads for each year from 2008 to 2010.
h. Refer Ex C1/T2/S2/S4/S5/S6 - Please provide a numerical table for OM&A that would show for example, sustaining OM&A, development OM&A, customer service expenses, and any other applicable breakdown to summarize for 2006, 2007 and 2008 the various elements of smart meter OM&A expenses applied for in this application.

Response

a. Yes, the $6.2 million for 2007 reflects actual spending.

b. The $8.366 ($8.4M) million is based on actual cost from 2005 to 2007 and is consistent with the $6.2 million 2007 amount.

	$M	
2005	1.9	
2006	3.9	
2007 to May 31, 2007	2.6	(total to May 2007 $8.366M)
Remaining 2007	3.6	
Total 2007 Only	6.2	(total for 2007 $6.212M)

c. $Millions

	2007	2008
AMCD		
Labour	0.5	0.6
Contract	1.1	1.2
AMRC		
Labour		
Contract	0.1	0.0
WAN		
Contract	0.8	0.8
AMCC		
Contract	0.8	0.8
Other		
Labour	0.1	0.0
Contract	2.9	2.2
Total	6.2	5.8

d. $Millions

	2008
Business Process redesign	
Labour	0.0
Customer Inquiries	
Labour	0.0
CIS and Integration	
Labour	
Contract	3.9
Total	3.9

e. The activities shown in item d are outsourced and so no additional FTEs are expected at this time.

f. The expected savings from the dispensation received by Measurement Canada are $2.8 million in 2008, $1.9 million in 2009 and $1.1 million in 2010.

g. Our current plan for the staff impacted by the reduction in requirement for manual meters reads is to redeploy them for smart meter installations up to 2010. They will also be eligible for retraining and be able to apply for job vacancies. The cost of manual meter reading being eliminated is $1.4 million for 2008, $10.1 million for 2009 and $14.7 million for 2010. These reductions reflect savings before the offsetting increase in OM&A and capital carrying costs on the smart meter assets in 2009 and 2010.

h. All of the smart meter related OM&A expenses applied for in this application are included in the OM&A costs shown in Table 8 of Exhibit C1, Tab 2, Schedule 2.

Ontario Energy Board (Board Staff) INTERROGATORY #127 List 1

Interrogatory

Ref: Exhibit D1 /Tab 3 /Schedule 2/ Issue 8.2

On page 23 under Table 6, Hydro One presents the following smart meter capital expenditure amounts:

- 2006 = $14.1 million
- 2007 = $76.7 million
- 2008 = $164.8 million

a. Please provide a continuity statement for smart meter gross fixed assets, accumulated depreciation, and net fixed assets, indicating the amounts for additions, retirements, depreciation and balances for December 31, 2006, May 31, 2007, December 31, 2007, April 30, 2008 and December 31, 2008.

b. Please explain whether all of the $14.1 million for 2006 was included in the $21.799 million capital cost for the period 2006 to May 31, 2007 which was approved by the Board on August 8, 2007 in the combined proceeding EB-2007-0063. If not, please provide a breakdown of "approved" and "not approved" amounts for 2006 smart meter capital expenditure.

c. In its December 18, 2007 filing, Hydro One had indicated that the smart meter capital expenditure forecast amount for 2007 was $118.6 million instead of the $76.7 million per February 20, 2008 filing. Please explain whether the reduction of $41.9 million capital expenditure in 2007 was the result of a reduction in smart meter installations which was forecasted to be 212,000 for 2007 on page 29 of the December 18, 2007 filing. If so, please provide the revised number of smart meter installations for 2007 and explain fully, in view of the reduction in smart meter installations in 2007, whether Hydro One will be able to install 370,000 smart meters in 2008 as indicated on page 29 of its filing.

d. Please complete the following table to calculate the unit capital cost for 2007 and the year/year percentage changes for unit capital costs. Please explain fully the changes in unit capital costs for each year:

	Pg 26 & 29: Number of Smart Meters Installed	Table 6 [Pg 23]: Smart Meter Capital Expenditure Amounts	Capital Expenditure Per Unit	Year / Year [i.e. 2007/2006 & 2008/2007] Percentage Change For Per Unit Capital Cost
2006	28,000	$14,100,000	$503.57	
2007	???,???	$76,700,000	$???.??	??.?%
2008	370,000	$164,800,000	$445.41	??.?%

On page 27, Hydro One indicates that the capital expenditure amounts associated with "minimum functionality" are $64.2 million and $136.5 million in 2007 and 2008 respectively.

e. Please complete the following table to calculate the unit capital cost for 2006 & 2007 and the year/year percentage changes for unit capital costs with respect to "minimum functionality". Please explain fully the changes in unit capital costs for each year:

	Pg 26 & 29: Number of Smart Meters Installed	Pg 27: Smart Meter Capital Expenditure Amounts for Minimum Functionality	Capital Expenditure Per Unit for Minimum Functionality	Year / Year [i.e. 2007/2006 & 2008/2007] Percentage Change For Per Unit Capital Cost
2006	28,000	$??,???,???	$???.??	
2007	???,???	$64,200,000	$???.??	??.?%
2008	370,000	$136,500,000	$368.92	??.?%

On page 27, Hydro One stated that the activities associated with the government's regulations concerning minimum functionality include the following work:

- Installing additional smart meters and advanced metering communication devices ("AMCD");
- Building and expanding the advanced metering regional collector ("AMRC"), and underlying networks to accommodate an increasing number of meters coming on-stream; and
- Commissioning and placing into service, hardware and software for the advanced metering control computer ("AMCC") to enable it to communicate and transmit quality meter data to and from the meter data management and meter data repository (MDM/R) and the Company's CIS.

f. Please provide a breakdown, for both 2007 [$64.2 million] and 2008 [$136.5 million], of the proposed "minimum functionality" smart meter capital costs for the above mentioned three work categories of 1), 2), and 3). Please provide, for each category, the costs for labour, material, contract, and other identifiable categories.

On page 27, Hydro One stated that the capital expenditure amounts associated with "incremental functionality" are $12.5 million and $28.3 million in 2007 and 2008 respectively.

g. Please complete the following table to calculate the unit capital cost for 2006 & 2007 and the year/year percentage changes for unit capital costs with respect to

"incremental functionality". Please explain fully the changes in unit capital costs for each year:

	Pg 26 & 29: Number of Smart Meters Installed	Pg 27: Smart Meter Capital Expenditure Amounts for Incremental Functionality	Capital Expenditure Per Unit for Incremental Functionality	Year / Year [i.e. 2007/2006 & 2008/2007] Percentage Change For Per Unit Capital Cost
2006	28,000	$??,???,???	$??.??	
2007	???,???	$12,500,000	$??.??	??.?%
2008	370,000	$28,300,000	$76.49	??.?%

On page 27, Hydro One stated that activities associated with "Incremental functionality" include the following work:

- Upgrades to our CIS system to provide for Time of Use billing and related required settlement changes. This aspect of the Smart Meter program is rooted in the government's desire and directive to create a conservation culture of which time of use rates are an integral part;
- Integration of the end to end systems including business process redesign. This integration ties the AMI systems implemented under minimum functionality with the IESO's MDMR and Hydro One's CIS system to allow the collection of time differentiated consumption data required for TOU billing; and
- The added cost of super capacitors in meters and batteries in the regional collectors (AMRC) that provide for real time outage reporting after and during loss of power. Having the ability to pin point outages and tie this information to our outage management system has the potential to increase customer service and reduce costs. When outages occur, especially during a major storm, there are instances where faults and damage are "nested". In these situations, without the knowledge of the state of individual services, it takes longer to locate outages and it is possible for crews to fix a problem and leave the area only to return to fix other problems downstream. This inefficient and extends outage times. Since Hydro One is changing all its meters by 2010, this provides a good opportunity to deploy this functionality effectively.

h. Please provide a breakdown, for both 2007 [$12.5 million] and 2008 [$28.3 million], of the proposed "incremental functionality" smart meter capital costs for the above mentioned three work categories of 1), 2), and 3). Please provide, for each category, the costs for labour, material, contract, and other identifiable categories.

i. Please comment on whether it is appropriate for Hydro One to charge the "added cost of super capacitors in meters and batteries in the regional collectors (AMRC) that provide for real time outage reporting after and during loss of power" to smart meter capital, since the added cost of super capacitors in meters and batteries in AMRCs are not listed among the items qualifying for "incremental functionality" costs in the 3rd paragraph of page 7 of the combined decision EB-2007-0063 [and outside of the box titled "Advanced Metering Infrastructure (AMI)" of the diagram attached as Appendix "D" to this decision]. If it is believed by Hydro One to be appropriate, please explain fully why.

j. Hydro One states "Having the ability to pin point outages and tie this information to our outage management system has the potential to increase customer service and reduce costs." Please indicate whether Hydro One has undertaken a study to determine these reduced costs. If so, please indicate the nature of these cost reductions and provide the estimated amount of savings that will flow from these reduced costs and to which account[s] these savings would be applied. Please explain why Hydro One is attributing the savings to these accounts.

On page 28 [of Exhibit D1 /Tab 3 /Schedule 2], Hydro One justifies the engagement of Capgemini for project management by stating, "Due to scope, complexity and specialized nature of the above tasks, the project management services and operation of a project management office (PMO) is provided by Capgemini. Capgemini was selected as the system integrator for Hydro One's smart meter program through a competitive RFP process in 2005. Although Hydro One is providing overall direction to Capgemini, the project management services and PMO are typically provided by the system integrator and is not a role that Hydro One is able to resource internally. Additional details on Capgemini's project management function are also provided as part of the discussion in Exhibit F1, Tab 1, Schedule 1 on smart meter Regulatory Asset accounts."

On page 10 of "Exhibit F1 /Tab 1 /Schedule 1", Hydro One lists the following 12 work streams for which the program management function provides full PMO services:

- Meter installation and field services;
- Commissioning of head-end systems (advanced metering control computer, or "AMCC", for 1.2 million meter points);
- Network Engineering;
- Integration of AMCC to MDMR to Hydro One's CIS;
- Billing and customer care;
- Settlements (retail and wholesale impact assessment);
- Customer Contact Centre (call centre to handle meter installation and TOU customer enquiries);

- CIS upgrade for TOU rates;
- New systems – data and synchronization gateway and exception management;
- Integrated business process design for moving from manual meter reading to an advanced metering regional collector (AMCR);
- Infrastructure Management (managing the procurement and implementation of computer hardware required for AMCCs, Integration, and TOU upgrades);
- Project management and tracking;

k. Please explain the specific nature of the services that the program management function provides to "meter installation and field services" shown under 1) above. Please explain why the program management functions required for meter installation and field services cannot be fulfilled internally by Hydro One's existing management function for meter installation and field services. Please fully explain why Hydro One uses the services of Capgemini for this purpose.

l. Please explain the specific nature of the services that the program management function provides to "billing and customer care" shown under 5) above. Please explain why the program management function required for billing and customer care cannot be fulfilled internally by Hydro One's existing management function for billing and customer care. Please fully explain why Hydro One uses the services of Capgemini for this purpose.

m. Please explain why the program management function required for Customer Contact Centre [shown under 7) above] to handle meter installation and TOU customer enquiries cannot be fulfilled internally by Hydro One's existing management function for customer contact. As explained by Hydro One in "Exhibit G1 /Tab 9 /Schedule 1", Hydro One was involved in a pilot TOU program as part of Conservation and Demand Management programs. Please explain why the management function required to handle TOU customer enquiries is not being handled by Hydro One's human resources who handled the pilot TOU program. Please fully explain why Hydro One uses the services of Capgemini for managing and handling meter installations and TOU customer enquiries.

n. Please explain the specific nature of the services that the program management function provides to "CIS upgrade for TOU rates" shown under 8) above. Please comment on whether or not the existing CIS system has already been upgraded for TOU rates in view of the pilot TOU program which was initiated by Hydro One as part of a CDM program. Please fully explain why Hydro One uses the services of Capgemini for managing the CIS upgrade for TOU rates.

Response

a) See the IR response in Exhibit H, Tab 1, Schedule 120, part a.

b) Of the $14.1M shown for 2006 only $5.4 million was approved by the Board on August 8, 2007.

	$M	
Total expenditures 2006	14.1	
Less: funds from CDM	6.4	
Exceed minimum	2.2	
Net amount approved for 2006	5.4	
2006	5.4	
2007	24.5	
Total Expenditures applied for	29.9	
Less		
Amounts not approved	8.1	(primarily inventory)
Amount approved	21.8	($21.799M per decision)

Note: the Board also disallowed $0.7M of Project Management so the actual approved amount was $21.1M.

c) The reduced expenditures in 2007 were not the result of lower than expected meter numbers (2007 actual meters installed was 222,831. The lower expenditures are attributable to a lag versus forecast for modifications to the CIS and Integration systems, and contingency allocated but not used.

Hydro One expects to install 370,000 meters in 2008.

d)

	Number of Smart Meters Installed	Smart Meter Capital Expenditures	Capital Expenditure / Unit	% Change Year over Year
2006	27,600	14,100,000	$ 511	
2007	222,831	76,700,000	$ 344	-33%
2008	370,000	164,800,000	$ 445	29%

In 2006 the higher unit expenditure reflects the up front cost of automating the change meter order process from a manual process to a fully automated system, spread over a low number of meter installs.

In 2007 very little work was done on the CIS system or the integration to the SME's MDMR and the upfront automation cost had essentially been completed. In addition, the installation of smart meters focused on the mass deployment of readily accessible lower cost residential and small commercial meters.

In 2008 there are capital costs included to upgrade the CIS system for TOU and to build the interfaces and integration systems to support the end to end process. Further, Hydro One plans to begin the installation of larger commercial smart meters (much more expensive on a unit basis) and to complete meters that were skipped in 2007 (such as inside meters that now require a scheduled second trip or where additional equipment such a meter socket adapters). The resulting year over year change in capital expenditures is higher than the year over year change in meter installations.

e)

	Number of Smart Meters Installed	Smart Meter Capital Expenditures Minimum Functionality	Capital Expenditure / Unit	% Change Year over Year
2006	27,600	5,413,000	$ 196	
2007	222,831	64,200,000	$ 288	47%
2008	370,000	136,500,000	$ 369	28%

The cost for 2006 was reduced for the CDM funding ($6.4M) previously approved by the Board (see response to b) above), which lowers the unit cost for 2006 relative to 2007.

The 2008 unit cost is higher as a result of the installation of more expensive commercial meters, completing meters that were inaccessible (additional trip and scheduling with the customer), and the use of meter socket adapters for odd form meters.

f) $Millions

		2007	2008
AMCD			
	Labour	4.9	10.9
	Contract	3.4	6.9
	Material	43.1	60.2
AMRC			
	Labour	1.0	4.9
	Contract	1.0	4.5
	Material	3.1	1.8
AMCC			
	Contract	1.0	1.1
	Material	2.2	5.3
Other			
	Labour	0.1	3.1
	Material	2.4	1.5
	Contract	2.0	4.2
	Other (e.g. contingency)	0.0	32.1
Total		64.2	136.5

g)

	Number of Smart Meters Installed	Smart Meter Capital Expenditures Exceeding Minmum Functionality	Capital Expenditure / Unit	% Change Year over Year
2006	27,600	-	$ -	
2007	222,831	12,500,000	$ 56	
2008	370,000	28,300,000	$ 76	36%

The unit cost of the super capacitors in the AMCD and batteries in the AMRC are consistent in 2007 and 2008. The increased unit cost in 2008 is due to increased costs for CIS changes and costs for optimization of the business process through an integrated transaction management system.

h) $Millions

	2007	2008
Upgrades to CIS		
Contract	4.6	12.6
Systems Integration (transaction management system)		
Contract	3.8	8.5
Supercaps and Batteries		
Material	4.1	7.2
Total	12.5	28.3

i) Hydro One's RFP for AMI included a requirement for real time outage management. The selected vendor incorporated (as part of the sealed meter / AMCD) super capacitors into the AMCDs and batteries into the AMRCs to provide the necessary power to the communications network to provide outage information in the event of a loss of power. The feature enables the pin-pointing of outage locations for more effective dispatch of trouble crews, it indicates where there are nested outages so trouble crews do not leave location only to return for downstream outages, and it provides outage information when customers are not home (which is an advantage in cottage areas where outages tend to be identified on weekends, resulting in the dispatch of trouble crews on overtime). In addition, once fully implemented it is expected call volumes will decline as customers become aware that Hydro One has this detection capability – this plus the impact on the effectiveness of outage

restoration will increase customer satisfaction and reliability. Although no specific cost benefit analysis has been done at this time, Hydro One is proceeding with the selected vendor solution since this is a one time opportunity. We will not be in a position again to add this feature on such a cost effective basis because travel and installation costs are a significant part of the cost which can be avoided if the work is done at the same time. These are long term assets and the benefits are expected to be available over a long period of time and are expected to exceed the nominal additional one time cost of incorporating this feature into the AMCDs and AMRCs (less than 10% of the cost of minimum specification).

It's also noted that although these costs are included as "exceeds minimum functionality" they do in fact support the reliability requirement under the AMI minimum specification. Battery backup in the AMRC provides ongoing power supply so while they, the AMRC, may be out of power in many cases meters (AMCD) that report into them may not. An AMRC supports many meters (up to 1000 in a mesh local area network) and it's likely the communications will overlay several feeders.

j) Please refer to i) above.

k) The program management and PMO function is required to provide an overall service to the entire smart meter program because all the workstreams identified must operate in an integrated fashion to be successful. For example, Network Engineering must work hand in hand with Meter Installation in Fields Services: Field Services records a GPS location when meters are installed, which then goes to the engineering group for conducting the RF studies for the AMRC; the RF model identifies possible AMRC pole locations which is then fed back to Field Services crews to schedule pole inspection (for power and space on the pole); any changes go back to Network Engineering for approval before Field Services installs the collectors / meters. These activities are all coordinated and monitored across the entire province (50 field locations), Similar coordination is required for Billing / Settlements / Customer Contact / New Systems and Integration.

With the above subset of examples in mind the following are the specific nature of services provided:

Works tream	Area	Task / Deliverables
12-PMO	Delivery Oversight	Provide delivery direction/guidance to workstream leads
12-PMO	Delivery Oversight	Provide direction/guidance to workstream leads for project change management
12-PMO	Delivery Oversight	Resolve delivery issues (for Cap workstreams)
12-PMO	Resource Management	Support resource acquisition and management
12-PMO	Facilities & Logistics	Prepare for meetings (schedule, room and resource bookings, etc.)
12-PMO	Financial Management	Conduct monthly re-forecasting
12-PMO	Financial Management	Obtain time tracking information from relevant Capgemini systems and subcontractor contactors systems for financial tracking and due diligence
12-PMO	Financial Management	Prepare and distribute client monthly financial reports
12-PMO	Financial Management	Prepare client due diligence financial materials
12-PMO	Financial Management	Provide oversight for time and expense reporting
12-PMO	Financial Management	Provide oversight of time and cost management
12-PMO	Financial Management	Respond to ad-hoc information requests

Works tream	Area	Task / Deliverables
12-PMO	Governance	Administer and attend program team meetings
12-PMO	Governance	Administer and participate in PMOLT (Project Management Leadership Team – Hydro One Line of Business Owners) monthly meetings
12-PMO	Governance	Administer Program IRAC (Issues, Risks, Assumptions and Changes) Logs
12-PMO	Governance	Assemble and send out program due diligence materials
12-PMO	Governance	Develop monthly program status report
12-PMO	Governance	Develop and modify as required the Program Governance Plan
12-PMO	Governance	Liaise with Audit
12-PMO	Governance	Prepare internal Capgemini Earned Value reports and provide required input into Hydro One earned value monitoring report.
12-PMO	Governance	Prepare for and participate in SC (Hydro One Steering Committee) meetings as required
12-PMO	Governance	Provide oversight of program control and administration
12-PMO	Governance	Provide support for program status meetings
12-PMO	Governance	Support Hydro One Audit in conducting project audits
12-PMO	Knowledge Manageme nt	Administer program Sharepoint site and procedures

Works tream	Area	Task / Deliverables
12-PMO	Knowledge Management	Enhance SharePoint to include an approvals workflow / other minor enhancements
12-PMO	Quality Management	Conduct Inergi stage-end reviews and QA
12-PMO	Quality Management	Conduct QA (Quality Assurance) activities for Customer/1 development
12-PMO	Quality Management	Conduct QA reviews
12-PMO	Quality Management	Develop program quality management plan
12-PMO	Quality Management	Develop program quality management plan
12-PMO	Quality Management	Manage deliverable approval matrix
12-PMO	Quality Management	Provide advice/guidance to workstream leads on quality management
12-PMO	Resource Management	Onboarding and Offboarding, as part of normal project staffing
12-PMO	Risk Management	Identify, coordinate, manage and report on program risk
12-PMO	Risk Management	Manage Program Issues, Risks, Assumptions and Changes
12-PMO	Risk Management	Provide advice/guidance on quality and risk management

Works tream	Area	Task / Deliverables
12-PMO	Schedule Management	Conduct quarterly rolling-wave re-planning; produce updated IPP (Microsoft Project cross work stream Integrated Project Plan) and milestone charts
12-PMO	Schedule Management	Manage program task status
12-PMO	Schedule Management	Provide oversight of schedule management
12-PMO	Strategy	Provide strategy/planning support

The activities above support all workstreams, including Meter Installation and Field Services. Many of these functions are "off the shelf" project methodology that systems integrators provide in large scale project such as this. Although Hydro One does have PM capabilities (for more traditional utility programs) we do not have staff that brings the capability and methodologies to blend IT as well as other diverse workstream tasks, activities, and plans.

l) Please see responses to part k) above for the Billing and Customer Care workstream deliverables (again tight integration is required across workstreams so the process from requirements, to use cases, work instructions, business process designs, that feed into systems design, code, build test, and commission of the CIS Upgrade and Integration workstreams are completed effectively – also many of the above are Capgemini deliverables)

m) Please see responses to part k)

For the TOU pilot under the CDM program the smart meters had already been installed (i.e. they were a very small subset of the smart meters installed as part of the smart meter project). As we move toward province wide implementation we will, as we do today, rely on the services of our outsource service provider Inergi to operate the customer contact centre. The scale of the call volume for full implementation (over 1 million) compared to the TOU pilot (about 500) is not comparable in scope, complexity or the need for effective efficient operations.

n) Please see responses to part k).

For the TOU pilot hourly readings were taken from our AMCC and put into our legacy interval meter customer system for VEE (manual files transfer). The verified billing quantities were then billed on a more manual basis (spreadsheet) for the small number of customers in the pilot. Our current CIS system does not have TOU capability and is being upgraded for this set of features (AMR scripts, TOU bill calc, TOU bill presentment, etc.) as well as building the integration requirements to accept data and synchronize accounts and related data on a near real time basis across AMCC and SME MDMR. This system will be automated to handle in excess of 1 million accounts billed monthly.

Ontario Energy Board (Board Staff) INTERROGATORY #128 List 1

Interrogatory

Ref: Exhibit F1 /Tab 1 /Schedule 1/ Issue 8.3

On page 2 under "Table 2: Distribution – Regulatory Assets Requested for Approval", Hydro One provides a summary of the following regulatory asset accounts [including three categories of smart meter variance accounts] requesting the disposition of their May 1, 2006, December 31, 2006, December 31, 2007, and April 30, 2008 balances:

- OEB Cost Account;
- Tax Changes Account;
- Retail Settlement Variance Accounts;
- Smart Meter Minimum Functionality Under-Recovery to May 31, 2007;
- Smart Meter Exceeding Minimum Functionality Under-Recovery; and
- Smart Meter Minimum Functionality Under-Recovery between June 1, 2007 and April 30, 2008.

a. Please confirm whether the disposition of the December 31, 2006, December 31, 2007, and April 30, 2008 balances for the three smart meter variance sub-accounts mentioned above will be part of the disposition of all the regulatory asset accounts shown above and Hydro One is seeking to have their disposition through the implementation of only one regulatory asset rate rider for each rate class as appropriate [i.e. without separate rate riders for smart meter sub-accounts]. Please provide the rate rider amounts for each of the above three categories of smart meter sub-accounts.

b. Please provide the table for Appendix E showing in detail how the revenue requirement amounts of $6.1 million, $10.6 million, and $11.7 million for December 31, 2006, December 31, 2007, and April 30, 2008, respectively are derived.

c. Has Hydro One followed the Board's guidance on the use of the smart meter main account 1555 – smart meter capital and recovery offset variance account, and main account 1556 – smart meter OM&A variance account in 2007 and for 2008? What sub-accounts has Hydro One used under these main accounts 1555 and 1556?

d. Has Hydro One applied to clear the balances in these various main and sub-accounts of 1555 and 1556 in this application? If so, please provide the evidence references that demonstrate how Hydro One has accumulated costs in the various accounts and how each component is supported to clear the balances in 1555 and 1556 to fixed assets, expense, income, etc.

e. If not, please provide a full description of how Hydro One has accounted for the capital expenditures, Capgemini contract costs, transfers to the meter fixed asset accounts, computer system software and hardware costs, meter heads, all additional equipment used in the installation of the AMI, incremental OM&A associated with smart metering, and depreciation in 2006, 2007 and 2008. How were the Capgemini contract costs assigned to the various asset cost pools?

f. Please describe the interest carrying charge assumptions Hydro One has made for main accounts 1555 and 1556 and all applicable sub-accounts under these main accounts. Please provide the calculations of the interest recovery in 2006, 2007 and 2008 that Hydro One believes it is entitled to with respect to capital costs, OM&A and depreciation recorded in accounts 1555 and 1556.
g. Has Hydro One claimed both (a) the short-term interest carrying charges on the capital component of account 1555; and (b) the long-term interest, used in the calculation of revenue requirement on the same assets? Amounts removed from the 1555 recovery offset variance sub-account, used to record rate adders, is based on a return on rate base methodology.

On page 6 & 7, Hydro One states: "Table 5 below details the revenue requirement (net of revenue received) related to smart meter minimum functionality up to May 31, 2007 that Hydro One is requesting recovery for in this proceeding. The revenue requirement was calculated based on the approach illustrated in Appendix E of the decision for proceeding EB-2007-0063."

h. Please provide the smart meter rate adder amounts that would clear the "Net Revenue Requirement to be Recovered" amounts of $3.6 million, $5.8 million, and $6.9 million for December 31, 2006, December 31, 2007, and April 30, 2008.
i. Please provide the smart meter rate adder amounts that would clear the "Net Revenue Requirement to be Recovered" amounts of $3.6 million, $5.8 million, and $6.9 million for December 31, 2006, December 31, 2007, and April 30, 2008.
j. Please confirm whether the revenue requirement amounts related to smart meter minimum functionality up to May 31, 2007 are with respect to the 62,914 smart meter installations up to May 31, 2007 approved in the Board's combined proceeding EB-2007-0063. If not, please provide the actual number of smart meter installations up to May 31, 2007 and explain fully the difference between this number and 62,914.
k. Please confirm whether the April 30, 2008 net fixed asset balance associated with the variance sub-account "smart meter minimum functionality up to May 31, 2007" will be incorporated into the rate base as of May 1, 2008. If so, please provide the gross fixed asset, accumulated depreciation and net fixed asset amounts for May 1, 2008.

Under the Section "2.4 Smart Metering Expenditures Exceeding Minimum Functionality" and at the bottom of page 8, Hydro One presents in "Table 6: Distribution – Smart Meter Exceeding Minimum Functionality Under-Recovery" the revenue requirement amounts of $0.6 million, $3.4 million, and $5.7 million for December 31, 2006, December 31, 2007, and April 30, 2008, respectively.

l. Please provide a table showing in detail how the above mentioned revenue requirement amounts for December 31, 2006, December 31, 2007, and April 30, 2008 are derived.

m. Please provide the smart meter rate adder amounts that would clear the "Revenue Requirement" amounts of $0.6 million, $3.4 million, and $5.7 million for December 31, 2006, December 31, 2007, and April 30, 2008.
n. Please indicate the number of smart meter installations and the period during which these smart meters were installed with respect to "Smart Metering Expenditures Exceeding Minimum Functionality".
o. Please confirm whether the April 30, 2008 net fixed asset balance associated with the variance sub-account "Smart Metering Expenditures Exceeding Minimum Functionality" will be incorporated into the rate base as of May 1, 2008. If so, please provide the gross fixed asset, accumulated depreciation and net fixed asset amounts for May 1, 2008.

Under the Section "2.5 Smart Metering Minimum Functionality Expenditures between June 1, 2007 and April 30, 2008" and at the bottom of page 11, Hydro One presents in "Table 7: Distribution – Smart Meter Minimum Functionality Under-Recovery between June 1, 2007 and April 30, 2008" the revenue requirement amounts of $11.3 million and $21.4 million for December 31, 2007 and April 30, 2008, respectively.

p. Please provide a table showing in detail how the above mentioned revenue requirement amounts for December 31, 2007 and April 30, 2008 are derived.
q. Please provide the smart meter rate adder amounts that would clear the "Net Revenue Requirement to be Recovered" amounts of $3.7 million and $9.4 million for December 31, 2007 and April 30, 2008.
r. Please confirm whether the number of smart meter installations for "Smart Metering Minimum Functionality Expenditures between June 1, 2007 and April 30, 2008" represent the installations for the period between June 1, 2007 and April 30, 2008 as well. If not, what is the period? Please provide the number of smart meter installations for this category.
s. Please confirm whether the April 30, 2008 net fixed asset balance associated with the variance sub-account "Smart Metering Minimum Functionality Expenditures between June 1, 2007 and April 30, 2008" will be incorporated into the rate base as of May 1, 2008. If so, please provide the gross fixed asset, accumulated depreciation and net fixed asset amounts for May 1, 2008.

Response

a. Hydro One is seeking disposition of the April 30, 2008 balances of the three smart meter accounts through the implementation of one regulatory asset rate rider for all the regulatory asset accounts included in Exhibit F1, Tab 1, Schedule 1. Details of the amounts to be recovered are provided in Exhibit F1, Tab 2, Schedule 1 and in the interrogatory response at Exhibit H, Tab 1, Schedule 122, part b.

b. The derivation of the revenue requirement amounts used to determine the balances in the smart meter regulatory asset accounts are provided in the response at Exhibit H, Tab 1, Schedule 120, part a.

c. Hydro One Distribution has followed the Board's guidance on the use of smart meter USofA accounts 1555 and 1556.

Hydro One is using account 1556 to track smart meter OM&A costs, and account 1555 to track capital expenditures and net revenue requirement (ie. revenue requirement net of recoveries, plus interest improvement).

Hydro One does not keep track of the detailed expenditures in accounts 1555 and 1556. However, the detailed expenditures are kept in our Peoplesoft project costing sub-ledger (see response to part e).

d. Hydro One has applied to clear the balances related to net revenue requirement, as described in the response to part a) above and also detailed in the response at Exhibit H, Tab 1, Schedule 120, part a.

e. All smart meter costs are captured under several cost groups which uniquely identify the nature of the underlying costs. Within each cost group are project numbers and within each project number are work orders, if required, which serve to provide an even greater level of detail for costs incurred.

The cost groups are:

- Meter Installation & Field Services
- Smart Meter Network
- AMI Head end Systems & Infrastructure
- Billing System & Infrastructure
- New Systems & Integration
- Program Management
- Integrated Business Process Design
- Change Management
- Communications
- Smart Meter Operations
- Application Operations & Sustainment

For example, under the cost group "Meter Installation & Field Services", there are project numbers set up to track the cost for meters; other meter-related costs such as

adapters; seals and meter rings; meter deployment; and meter installation. Within the project "Meters", there are work orders to capture costs for meter purchases, meter handling by stock keepers, and meter transportation costs from Hydro One's meter shop to the various operation centres for the delivery of meters to be installed at customer premises.

All capital and OM&A expenditures including those for the Capgemini contract costs, computer system software and hardware costs, additional equipment used in the installation of the AMI are assigned to one of these cost group /project / work order combinations.

Each project is assigned to an asset identifier which for most smart meter costs is the Meters asset.

f. Hydro One is only interest improving the net revenue requirement amount included as part of account 1555. The calculation of interest improvement for each of the three smart meter accounts is shown in the interrogatory response at Exhibit H, Tab 1, Schedule 120, part a.

g. Hydro One included a return on rate base as part of the calculation of revenue requirement, as well as interest improvement on the net revenue requirement as discussed in part f) above. Details of the return on rate base calculation for each of the three smart meter accounts is shown in the interrogatory response at Exhibit H, Tab 1, Schedule 120, part a.

h. Disposition of the regulatory asset balances related to smart meter minimum functionality up to May 31, 2007 as at various points in time (including interest improvement to April 30, 2008) are shown below:

	Disposition of Balance as at:		
$ millions	Dec. 31, 2006	Dec. 31, 2007	Apr. 30, 2008
Balance	3.6	5.8	6.9
Add interest to Apr. 30, 2008	0.3	0.1	0.0
Total to be recovered as at Apr. 30, 2008	3.9	5.9	6.9
Annual recovery (over four years)	**1.0**	**1.5**	**1.7**

i. See response to part h above.

j. Yes, this is confirmed.

k. Hydro One has included all in-service additions associated with smart meters in the calculation of rate base as at December 31, 2007 and December 31, 2008.

l. See interrogatory response at Exhibit H, Tab 1, Schedule 120, part a.

m. Disposition of the regulatory asset balances related to smart meter excess functionality as at various points in time (including interest improvement to April 30, 2008) are shown below:

	Disposition of Balance as at:		
$ millions	Dec. 31, 2006	Dec. 31, 2007	Apr. 30, 2008
Balance	0.6	3.4	5.7
Add interest to Apr. 30, 2008	0.1	0.0	0.0
Total to be recovered as at Apr. 30, 2008	0.7	3.4	5.7
Annual recovery (over four years)	**0.2**	**0.9**	**1.4**

n. The following are the periods and numbers of meters installed with respect to Smart Metering Expenditures Exceeding Minimum Functionality

	Number of Smart Meters Installed	**Cummulative Number of Smart Meters Installed**
CDM	25000	
Other	2,600	
2006 Total	**27,600**	**27,600**
to May 31 2007	62,914	
June to December 31 2007	159,917	
2007	**222,831**	**250,431**
to April 30, 2008	146,665	
May to December 31, 2008	223,335	
2008	**370,000**	**620,431**

o. See response to part k above.

p. See interrogatory response at Exhibit H, Tab 1, Schedule 120, part a.

q. Disposition of the regulatory asset balances related to smart meter minimum functionality after May 31, 2007 as at various points in time (including interest improvement to April 30, 2008) are shown below:

	Disposition of Balance as at:		
$ millions	Dec. 31, 2006	Dec. 31, 2007	Apr. 30, 2008
Balance	0.0	3.7	9.4
Add interest to Apr. 30, 2008	0.0	0.0	0.0
Total to be recovered as at Apr. 30, 2008	0.0	3.7	9.4
Annual recovery (over four years)	**0.0**	**0.9**	**2.3**

r.

	Number of Smart Meters Installed	**Cummulative Number of Smart Meters Installed**
CDM	25000	
Other	2,600	
2006 Total	**27,600**	**27,600**
to May 31 2007	62,914	
June to December 31 2007	159,917	
2007	**222,831**	**250,431**
to April 30, 2008	146,665	
May to December 31, 2008	223,335	
2008	**370,000**	**620,431**

s. See response to part k above.

Ontario Energy Board (Board Staff) INTERROGATORY #129 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / Attachment A / p. 3 of 134/Issue 3.1
There is no amount entered for "Approved Low Voltage Wheeling Adjustment" at Step 8 of Sheet I3 TB Data. Please provide Hydro One's budgeted amount for charges paid to host distributors? Please also identify where is this category of cost included in the budget, and how is it allocated to the customer classes?

Response

Hydro One does not budget amounts to be paid to Host Distributors for "wheeling" type charges. These charges are recorded in a Regulatory Asset Variance Account (i.e. RSVA LV Wheeling) and are charged to customers when the variance accounts are being cleared. The proposed Rider # 3 includes RSVA LV Wheeling and is allocated to customer classes based on energy consumed. Please see Exhibit G1, Tab 5, Schedule 1, Table 1.

Ontario Energy Board (Board Staff) INTERROGATORY #130 List 1

Interrogatory

Ref: Halton Hills Hydro Inc. 2008 EDR Application EB-2007-0696, Round 2 Board staff Interrogatory No 7/ Issue 3.1

The host distributor's evidence is that Hydro One requested changes to its system, with the effect that Halton Hills Hydro Inc no longer needs a wheeling charge. Part of the interrogatory and the response in the reference are excerpted for convenience:

"Did Halton Hills Hydro apply for wheeling rates as part of its 2006 application? If not, why has Halton Hills Hydro not applied for such rates as directed in the (RP-2004-0153/EB-2004-0235) decision and order?

Halton Hills Hydro Inc. did not apply for wheeling rates as part of its 2006 application. Effective on, or about, May 1, 2006 at the request of Hydro One Networks Inc., Halton Hills Hydro Inc. made changes to the distribution system removing the necessity for calculating wheeling charges. At that time, Hydro One Networks Inc. became a GS 1,000 to 4,999kW commercial class customer of Halton Hills Hydro Inc. Therefore, due to this occurrence, Halton Hills Hydro Inc. did not file a request to create a "separate wheeling power rate class".

a. Please confirm that Hydro One had earlier requested that Halton Hills should conduct a cost of service study and develop a separate wheeling rate (RP-2004-0153/EB-2004-0235).
b. Please confirm that Hydro One made the request for changes to the distribution system, as described in the response to the interrogatory, and that the change in status from embedded distributor to General Class customer was an intended outcome of the request.
c. If both a) and b) are confirmed, please explain the rationale for the change to Hydro One's request, and provide an estimate of the cost impact on Hydro One of being billed as a General Service class customer rather than paying an allocated share of Halton Hills Hydro's LV system.

In respect to HONI's costs incurred as an embedded distributor:

d. Is the cost of wheeling estimated from a detailed list of revenues approved for the host distributors?
e. Are there instances with host distributors other than Halton Hills Hydro Inc, in which Hydro One has requested to be invoiced as a regular customer rather than an Embedded Distributor? Why?
f. In addition to any instances identified in part b), does Hydro One intend to such requests of other host distributors in the future?

Response

a. Hydro One confirms that it had requested that Halton Hills should conduct a cost of service study and develop a separate wheeling rate as part of Proceeding RP-2004-0153/EB-2004-0235.

b. Hydro One did request Halton Hills' concurrence to deregister a wholesale meter point. As part of a temporary arrangement to facilitate Hydro One's deregistration of its embedded points, Hydro One agreed with Halton Hills to have its supply points billed as a General Service class customer, since Halton Hills did not have any other applicable OEB approved rate to charge Hydro One for the embedded point of supply. Hydro One understood from Halton Hills that they would apply for an LV type rate as part of their next rate application.

c. As stated above, billing at General Service rates was a temporary solution. Hydro One does not have the information on what it would have paid Halton Hills at Halton Hills' LV type rates since Halton Hills does not have such a rate. Presumably, an LV type rate would be lower than a General Service rate.

d. No, Hydro One does not estimate the cost it will incur as an embedded distributor. Hydro One records all such charges in a variance account for future disposition.

e. Yes, there are other instances where Hydro One is an embedded distributor and is being charged General Service type rates from the host distributor, besides the Halton Hills point of supply. The reason is not that Hydro One has requested to be invoiced as a General Service customer but rather that the host distributors do not have LV type rates approved.

f. Hydro One continues to maintain that host distributors need to apply to the OEB for approval of LV type rates for embedded points of supply. This is consistent with the OEB's 2006 EDR Handbook, section 10.7 where a recommended approach is presented for host distributors to develop LV type rates.

Ontario Energy Board (Board Staff) INTERROGATORY #131 List 1

Interrogatory

Ref: Exhibit G2 / Tab 94 / Schedule 1 / page 1, and Schedule 2 / page 1/Issue 7.1

a. Are all customers classified as Embedded LDC in Schedule 2 now proposed to be classified as Sub-Transmissions (ST) customers per Schedule 1? If not, in what other class(es) are current Embedded LDC's included?
b. Are all customers classified as Embedded Direct in Schedule 2 now proposed to be classified as Sub-Transmissions (ST) customers per Schedule 1? If not, in what other class(es) are current Embedded Direct customers included?

Response

a. Yes, all Embedded LDC are proposed to be classified as being in the ST class.

b. Yes, all Embedded Direct customers are proposed to be classified as being in the ST class.

Ontario Energy Board (Board Staff) INTERROGATORY #132List 1

Interrogatory

Ref: Exhibit G1 / Tab 2 / Schedule 3 / p. 9/Issue 7.1
To better understand the proposed ST customer class:

a. What will be the largest customer in the proposed Sub-transmission ST class? What will be the smallest customer? What classes are those customers in currently?
b. Based on recent billing data for customers that are proposed to be in the ST class, what is the highest average monthly load factor of any customer in the proposed class. What is the lowest? What classes are the customers with those load factors in now?
c. What is the largest number of Delivery Points that a single ST customer will have in the proposed class?

Response

a. The largest customer would be an Embedded Distributor, (approx. 265 MW), currently in the LV-LDC class. The smallest customer would be an Embedded Distributor, (approx. 100 kW), currently in the LV-LDC class

b. For customers proposed to be in the ST Class:
The highest load factor is 92% for a customer currently in the LV-Directs class.
The lowest load factor is 9% for a customer currently in the LV-LDC class.

c. The largest number of Delivery Points that a single ST customer would have is 23.

Ontario Energy Board (Board Staff) INTERROGATORY #133 List 1

Interrogatory

Ref: Exhibit G1 / Tab 2 / Schedule 3 / p. 9/Issue 7.1

a. Did Hydro One consider two or more classes of customers that would be served at 13.8kV and above, eg embedded distributors considered separately from the remainder of the proposed ST class, former Transmission class as separate, etc.?
   i) If so, what alternatives were developed in sufficient detail to yield approximate cost allocation results, and what were the results?
   ii) If not, why not?

b. Does Hydro One expect to have cost savings related to Metering and/or Billing as a result of discontinuing the classification of Embedded Distributor and classifying those distributors as ST customers? If so, what is the approximate amount of the savings?

c. Does Hydro One expect to have cost savings related to Metering and/or Billing as a result of discontinuing the classification of Embedded Direct and serving those customers as ST customers? If so, what is the approximate amount of the saving?

Response

a. No, Hydro One did not consider two or more classes of customers for customers served at 13.8 kV and above.

One of the criteria considered in proposing the 12 customer classes is to reduce the number of existing customer classes. Since the existing OEB approved Low Voltage class currently includes all embedded Distributors and all Direct customers, consideration was not given to splitting this customer group. Direct customers are customers with average consumption above 5 MW, that prior to market opening were supplied by Ontario Power Generation. Another criteria considered was to group all customers according to their asset utilization. Embedded distributors supplied at 13.8 kV and above use the same assets as all other customers that are proposed to be grouped in the new Sub-Transmission class and therefore, no consideration was given to treat them separately.

b. and c.

No, Hydro One does not expect any cost savings related to Metering and/or Billing of Embedded Distributors or Embedded Direct customers. Billing and Metering for these customers will continue to be performed in the same manner as it is done now. Classifying these customers now as part of the new Sub-Transmission class will not change the Billing and/or Metering applicable to these two types of customers.

Ontario Energy Board (Board Staff) INTERROGATORY #134 List 1

Interrogatory

Ref: Exhibit G1 / Tab 2 / Schedule 4, and Exhibit G2 / Tab 3 / Schedule 1 / p. 3, and Exhibit G2 / Tab 5 / Schedule 1 p. 3/Issue 7.1

The reference in Exhibit G1 describes the "Density Review" as identifying areas that meet the Urban Density criteria. In the first reference in Exhibit G2, there is a list of some fourteen Acquired Distributors that were analyzed to identify customers that might be classified in one of the new Urban classifications.

a. Where these Acquired Distributors chosen on the basis of customer density, distributor size, or some other factor(s)?
b. Referring to the second reference in Exhibit G2, did all Acquired Distributors fall into either an Urban Density Zone or a Medium Density Zone?
c. If distributor size was a factor, were any alternative size criteria considered to develop a larger number of zones, so that customers of smaller Acquired Distributors that do not qualify for the most favourable rates might at least qualify for a rate lower than the highest one? If so, please describe the criterion and why it is not proposed for use in this application.
d. Were alternative definitions of density considered, such that there might be more than one class of customers with density higher than the proposed R1 and GS classifications? If so, please describe the alternative density limit(s) and why it/they are not proposed for use in this application.
e. Did Hydro One analyze the density of those customers that did not qualify for the Urban classification in the selected Acquired Distributor service areas? What is the density of the non-Urban customers in Acquired Distributors, compared with the density of the Legacy customers that they are proposed to be grouped with, and what is the density of the customers who are proposed as Urban? If the comparison of densities was not made, why not?

Response

a. The Acquired Distributors selected for density review purposes were those in areas where the customer count exceeded 3,000 in a compact (urban) area that included both Acquired and Legacy customers.

b. Yes, all the Acquired Distributors have at least 100 customers and line density of at least 15 customer per km which would make them either an Urban or Medium Density Zone.

c. No, distributor size was not a factor.

d. No, alternative definitions of density were not considered.

e. The comparison of densities was not made since all Acquired customers either meet the current Urban or Medium Density definitions.

Ontario Energy Board (Board Staff) INTERROGATORY #135 List 1

Interrogatory

Ref: Exhibit G2 / Tab 5 / Schedules 5 and 6/Issue 7.1
The Total Loss Factor proposed for the customers of many Acquired Distributors in Schedule 6 ("TLF new", 16th data column) are considerably higher than the current loss factors in Schedule 5 ("TLF old", 16th data column). Is the appropriateness of the new TLF's addressed in the pre-filed evidence? If so please provide the reference.

Response

Exhibit G1, Tab 10, Schedule 1, page 2, line 16 to page 3, line 8, explains how the proposed Loss Factors have been derived.

Ontario Energy Board (Board Staff) INTERROGATORY #136 List 1

Interrogatory

References: Exhibit G1 / Tab 2 / Schedule 3 / p. 4, and Exhibit G2 / Tab 5 /Schedule 1 / p. 3

Has Hydro One conducted a survey or inquiries on whether the 210 customers in Caledon OH-07 have a similar pattern of use and/or similar density?, If so, was the result of the survey or inquiries such that it is reasonable to include the Caledon customers with the typical customers in the Seasonal class as described in the second reference? ? If no such investigation has been conducted, please explain the rationale for basing the proposed rates of these customers in Caledon on the seasonal customer distribution rates.

Response

Hydro One did not conduct a survey or enquiries on whether the 210 customers in Caledon OH-07 have a similar pattern of use and/or similar density.

The reason Hydro One is proposing to classify these 210 customers as seasonal is that they were formerly Ontario Hydro seasonal customers. This is documented in the description of the current customer classes for Caledon provided in Exhibit G2, Tab 18, Schedule 2, page 1, which states that: “Residential OH-07 is for the former Ontario Hydro R4 class rates (outside the town of Bolton)”.

Ontario Energy Board (Board Staff) INTERROGATORY #137 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1
Please provide a copy of the most current cost allocation model as an official part of this application. Please also provide the following:

a. Please file a version with the customer classes as shown on pp. 4-5 of the Exhibit, and not with 270 classes as described at p. 1;
b. Please provide a complete version in electronic form but it is necessary to provide a paper copy of only worksheets I2, I6, I8, O1, O2, and E2
c. If not included in this version of the cost allocation model, please include a copy of the diagram "Dx System and Customers – ST Basis" that was included in the Hydro One's filing EB-2007-0001

Please describe the cost basis for the following charges or credits, by indicating the relevant results in the Hydro One cost allocation model, if applicable:
d. USL credit (Ref: Exhibit G2 / Tab 1 / Schedule 1 / pp. 13 & 19)
e. ST monthly service charge, ST common line, and two specific line charges (Ref: Exhibit G2 / Tab 94 / Schedule 1 / p. 2)
f. Transformer Ownership Allowance (Ref: Exhibit G1 / Tab 4 / Schedule 6, and Exhibit G2 / Tab 1 / Schedule 1 / p. 12).
g. Sentinel Lights miscellaneous revenue (Ref: Exhibit E3 / Tab 1 / Schedule 1 / p. 2)

Response

a. This is provided in Exhibit G2, Tab 1, Schedule 1, Attachment A , filed on February 28, 2008.

b. A complete electronic version of Hydro One Distribution's Cost Model, in PDF format, has been provided in the same February 28, 2008 filing. Refer to Exhibit G2, Tab 1, Schedule 1, Attachment A.

c. Please see Attachment A.

d. The USL credit was extracted from the Cost Model Tab O3.5 USL Metering Credit. Refer to Exhibit G2, Tab 1, Schedule 1, Attachment A, which contains the Cost Model.

e. The cost basis for the ST monthly Service charge is as follows**:**
The amount recovered by the proposed ST Service Charge of $188 plus the amount recovered by the proposed ST Meter Charge equals what would have been recovered

by the ST "Max SrChg" Service Charge value of $372 in the OEB Cost Allocation model (cell I19 on the "Scenarios" sheet).

In other words, the OEB Cost Allocation model identified $372 as the ST "Max SrChg" Service Charge. Removing ST meter costs revised the Service Charge to $188. That revision was offset by introducing the Meter Charge, charged solely to those customers for whom Hydro One owns the ST meters.

The cost basis for the ST Specific Line and Primary Specific Line rates is as follows:

The cost of Distribution Lines was taken from the OEB Cost Allocation model, and divided by the unit-cost-weighed lengths of ST line and Primary Line to produce the two rates: an ST Specific Line rate per km and a Primary Specific Line rate per km. These values were consistent with the Common Line rate when the Revenue-Cost Ratio equalled 1, so these values were prorated in proportion to the Common Line rate when the Revenue-Cost Ratio equalled 1.15. This produced the proposed Specific Line rates.

The cost basis for the ST Common Line rate is as follows:
From the variable revenue requirement, (at Revenue-Cost Ratio = 1), allocated to ST by the OEB Cost Allocation model, was subtracted, at Revenue-Cost Ratio = 1, the amounts recovered via the HVDSs rates, the LVDs-low rate, and the Specific Line rates. Added to the result, was the amount under collected by the Service Charge due to fixing the Service Charge at a value lower than "the amount allocated to Service Charges divided by the number of delivery points" ***.**
This result was divided by the charge determinant kW to get the Common Line rate at Revenue-Cost Ratio = 1. This rate was then increased to get the rate for Revenue-Cost Ratio = 1.15.

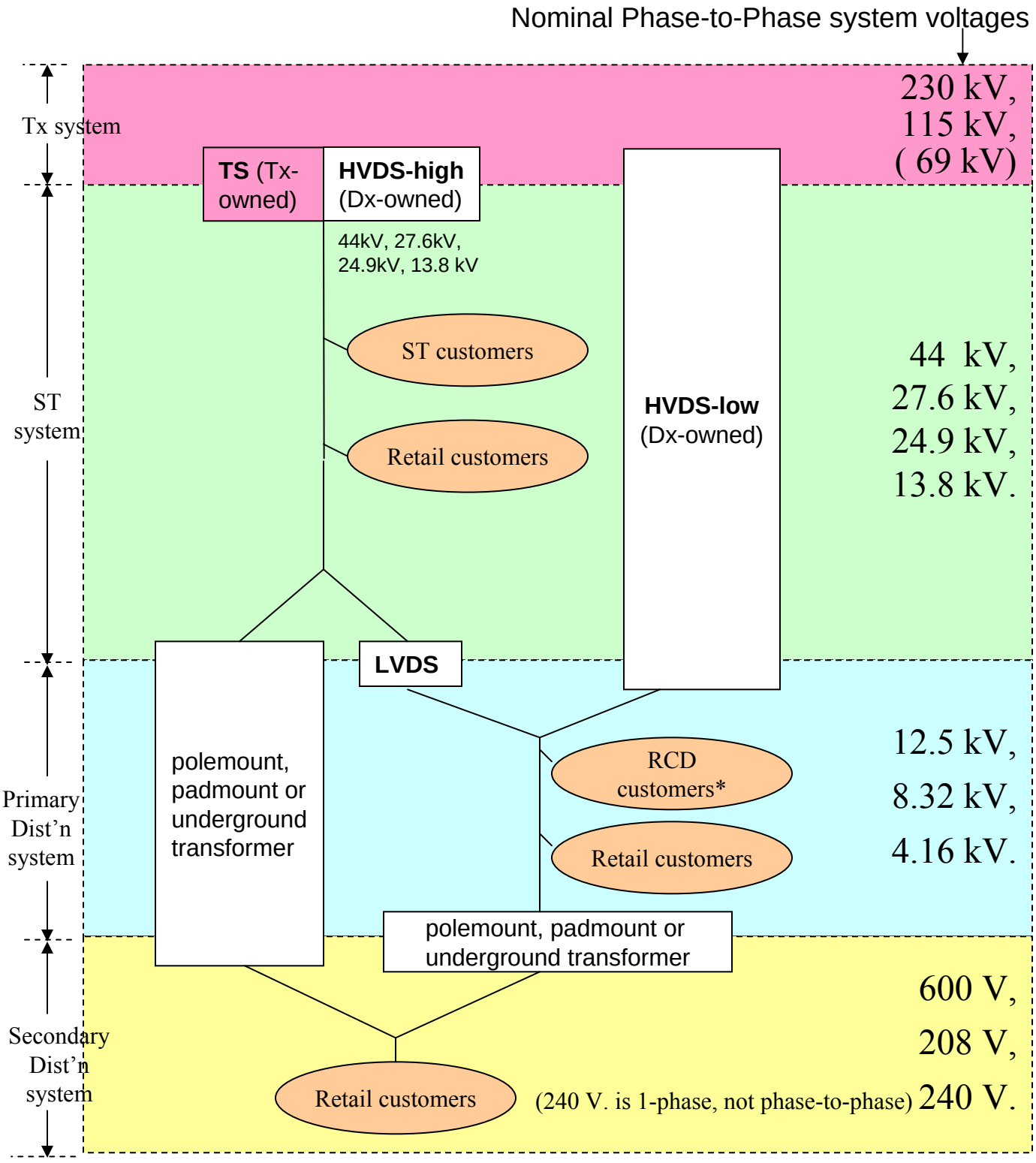
***** What this means is that the amounts recovered by the proposed Service Charge and Meter Charge are less than the fixed amount allocated to the ST class. This difference is recovered through the ST Common Line rate.

f. The Transformer Ownership Allowance proposed by Hydro One is the current approved rate of $0.60 per kW and is not from the Cost Model.

g. The Hydro One cost allocation model is not used in determining the cost basis for sentinel lights miscellaneous revenue.

To determine the sentinel lights miscellaneous revenue, Hydro One Distribution uses a revenue requirement model. The sentinel lights revenue requirement include costs that are directly attributable to sentinel lights and a portion of common shared charges.

Dx System and Customers – ST basis



* RCD customers are embedded distributor LDCs whose delivery points are between 12.5kV and 4.16kV (nominal phase-to-phase voltages).
RCD = "Rural-Connected Distributor"

Ontario Energy Board (Board Staff) INTERROGATORY #138 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / p. 8

a. Please provide a description of the sub-accounts of Account 1860 Meters, and if applicable describe how these sub-accounts are used to develop unit costs for the Meter Capital input worksheet I7.1.
b. Please provide a brief summary of the meter cost weightings assigned to the Sub-transmission class, including information on how uniform or diverse the equipment and technical requirements are across the various types of customers that are proposed for inclusion in this class.

Response

a. 1860 USoA for Meters is decomposed into 4 sub-accounts: Single Phase, Poly Phase, LV and Smart Meter.

These sub-accounts were not used to develop the unit costs for the Meter Capital input work sheet I7.1. The Meter Capital of I7.1 were mapped to the appropriate Sub-Account in E2 Allocators to more accurately allocate Meter costs across the Rate Classes using the sub-accounts. For example, no Poly Phase Capital Costs are assigned to the Residential rate classes.

b. The Sub-Transmission class meter cost weightings were developed using the simple formula:

$$\text{Weighted Unit Cost} = \frac{\#\text{ Units x [Meter Cost + Installation Cost]}}{\#\text{ Units}}$$

The largest cost component is the installation cost, which reflects equipment and technical requirements. The installation cost of ST customers connected on 44 kV is higher than those connected at a lower voltage. Typically, the Directs and LDCs moving to this class would have the most expensive meters, while the General Service Retail and Acquired customers moving to this class would have lower costs. Most of the customers in the ST class are Directs or LDCs.

Ontario Energy Board (Board Staff) INTERROGATORY #139 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / p. 8 -9

a. If the Hydro One cost allocation model includes a weighting factor for Services that are different from the default factors for any class(es), please provide a brief description and justification of the weighting factor(s)
b. Please provide a brief description of the Meter Reading Optimization analysis, including a description of the Meter Reading weight(s) applied to various situations and a listing of the weight applied to each customer class.
c. Please confirm that the Hydro One cost allocation model uses the default weightings from the model distributed by the Board for Billing costs, or provide a description of weights other than the default amounts.

Response

a. Hydro One Distribution's Cost Model does not use any Services weighting factors.

b. Meter Reading Optimization

Over a period of a few meter reading cycles, information was collected on the driving distances for each meter reading route. This travel distance along with the number of meters read in the route provided information on customer densities and the average distance between meters.

Information was collected from discussions with other utilities on meter reading productivity levels for various customer densities and/or travel distance between meters. From these discussions and internal analysis, benchmarks were determined for the meter readings per day for various average distances between meters. The listing of the Rate Classes and Meter Reading weights applied are:

1	UR, UGe, UGd
1.25	R1, GSe, GSd
2	R2
2.5	Seasonal

c. Hydro One Distribution adopted the default Billing Costs from the model distributed by the Board for the proposed rate classes: 1 for Residential (UR, R1, R2, Seasonal, Street/Sentinel lights), 2 for small General Service (UGSe, GSe), 7 for large General Service (UGSd, GSd, DG) and 15 for Large User (ST).

Ontario Energy Board (Board Staff) INTERROGATORY #140 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / p. 9

a. Please provide a brief description of the basis for Direct Allocation of accounts 5610, 5615, and 5665.
b. If applicable, please provide a description of how the following types of costs are allocated in the Hydro One model:
   i) management salaries and expenses in account 5610 that are not directly allocated
   ii) administrative salaries and expenses in account 5615 that are not directly allocated,
   iii) general expenses in account 5665 that are not directly allocated.

Response

a. The basis for the Direct Allocation of accounts 5610 and 5615 is the number of Interval Meter Delivery points per Rate Class. The costs captured in these accounts mainly relate to the salaries of personnel dealing with the Large Customers who are all Interval Metered.

   For Account 5665, Sentinel Light expenses are directly mapped to the Sentinel Light Rate Class and the non-Sentinel Light expenses are then allocated to the Rate Classes by the number of Interval Meter Delivery points.

b. The costs in Accounts 5610, 5615 and 5665 which are not handled as part of I9 Direct Allocation are allocated to the Rate Classes based on the default allocator of O&M as listed in E4 TB Allocation Details.

Ontario Energy Board (Board Staff) INTERROGATORY #141 List 1

Interrogatory

References: Exhibit G2 / Tab 1 / Schedule 1 / page 16, and Exhibit G2-1-1 / Attachment A / page 2

To assist in understanding how Hydro One's additional allocators are used in its model, please explain how the total amount of Account 1815-4 'HVDS – lo LV Shared' is allocated to classes. Include a description of the allocator 1815 – 4D, described as 'High Voltage DS Low LV – LV Only'. If any other allocator is used to allocate part of the account, include a description of that allocator and the rationale for how the account is divided up in preparation for allocation.

Response

The HVDS asset account of 1815 is being sub-divided into 5 sub-accounts:

1815-1	HVDS Rural
1815-2	HVDS – Lo LV Specific
1815-3	HVDS – Hi LV Specific
1815-4	HVDS – Lo LV Shared
1815-5	HVDS – Hi LV Shared

1815-1 is allocated using Allocator BCP12PB which is based on the model default of BCP12 with the ST Class excluded. This is because the remaining Assets in 1815-2/3/4/5 are all allocated 100% to the ST class. Thus all Allocators 1815-2D/3D/4D/5D are all 100% ST.

Analysis was done based on the ST customer connectivity to HVDSs. Their load as compared to Retails' load off these HVDSs was used to allocate the Book Value of these Stations between Retail versus ST.

Once the HVDS assets are divided between Retail and ST, the allocator for Retail is Class Coincident Peaks.

Ontario Energy Board (Board Staff) INTERROGATORY #142 List 1

Interrogatory

Ref: Exhibit G1 / Tab 2 / Schedule 3 / p. 9
Hydro One proposes to combine formerly separate groups into a single Sub-Transmission (ST) class.

a. Does Hydro One have available alternative runs of its cost allocation model in which some or all of the affected groups of customers listed in the reference are considered as separate classes, eg. all embedded distributors considered as a class separate from other embedded and LV customers?
b. If available, please provide copies of the worksheet O1 from the runs of the model, together with a description of the assumptions sufficient to understand how costs were allocated.
c. If not available, why were such cost allocation studies not conducted?

Response

a. Hydro One did not complete alternative runs of its cost allocation models in which some or all of the affected groups of customers being proposed to be part of the new Sub-Transmission (ST) class are considered as separate classes.

b. Not applicable.

c. The reason alternative runs were not carried out is that all the customers proposed to be part of the new ST class use similar Hydro One assets, and to better reflect cost causality, they are proposed to be grouped together. Another criteria in Hydro One's rate class proposals is to reduce the number of customer classes. Treating these customers as separate classes would increase the number of proposed customer classes.

Ontario Energy Board (Board Staff) INTERROGATORY #143 List 1

Interrogatory

Ref: Exhibit G1 / Tab 2 / Schedule 3 / p. 9
If there are cost savings anticipated as a result of discontinuing the classes of Embedded Distributor and Embedded Direct, do such savings affect the allocation of costs with the benefit accruing to the ST class, or are the savings allocated to all customer classes?

Response

There are no cost savings as a result of discontinuing the classes of Embedded Distributors and Embedded Directs.

Ontario Energy Board (Board Staff) INTERROGATORY #144 List 1

Interrogatory

Ref: Exhibit G1 / Tab 4 / Schedule 2 / Table 1, and Exhibit G2 / Tab 5 / Schedule 1 / pp. 9 -12/ Issues 7.3

The second data column in the first reference shows "Proposed Fixed Charge ($/Customer)" with a single value per customer or connection for each class. In the second reference, the proposed service charge in some classes varies considerably depending upon the customer's current classification, for example there are five proposed charges in the GSd class on page 12 varying from $38.68 to $207.30.

a. Is the variation in the charges intended to be a permanent or a transitional design?
b. How is the single charge (shown in the first reference) chosen from the range of charges that are proposed in the second reference?

Response

a. The variation in the charges is intended to be a transitional design resulting from phasing in to the target rates over a four year period in order to limit bill impacts to customers. This also allows Hydro One to recover the revenue requirement from each customer class in each year.

b. The single charge is the target service charge and it was chosen as the charge of the predominant group in each class if the value was between method a) and method c) in the OEB cost allocation model. If not, method c) provided the value for the target service charge. This is described in Exhibit G1, Tab 4, Schedule 1, page 1, line 13 to page 2, line 4. The exception is for the UGD class, where method a) determined the proposed fixed charges because the predominant group fixed charge is lower than the value determined by method a).

Ontario Energy Board (Board Staff) INTERROGATORY #145 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / p. 20/ Issues 7.3
How much revenue does Hydro One forecast that it will receive from the embedded distributors during the test year using the ST customer charge together with the Common Line Charge? How much revenue is forecast to be received from embedded distributors from the ST rates other than the two rates in the previous sentence?

Response

At a Revenue Cost Ratio of 1.15, the amount of revenue forecast to be received from the embedded distributors during the test year from the ST customer charge together with the Common Line Charge is $15.7M.

The revenue forecast to be received from the embedded distributors from ST rates other than the two rates above is $5.2M.

Ontario Energy Board (Board Staff) INTERROGATORY #146 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / Attachment A / p. 37, and Exhibit G2 / Tab 94 / Schedule 1 / p. 2/ Issues 7.3

a. Please describe the typical situations in which Hydro One would own the meter for a customer in the Sub-transmission class and charge the proposed Meter Charge at $553 per month, and conversely the situations in which the ST customer would typically own its meter and avoid this charge.
b. Please provide a brief description of the costs considered in deriving the proposed Meter Charge. Given that the range of unit customer costs in the first reference is $192.71 - $372.12, is the proposed charge cost-justified?
c. Would ST customers that are currently G3 or F3 customers be charged the Meter Charge? If not, why not? If so, please provide the bill impact of such customers over a representative size range, showing the meter charge either as a component within the new Monthly Service Charge or as a separate charge.

Response

a. Customers in the Sub-Transmission class who choose to be IESO market participants for their Hydro One embedded distribution delivery points would own their meters. On the other hand, customers who choose not to participate in the IESO market for their Hydro One embedded distribution delivery points, would not own the meters.

b. The two cost components used to derive the proposed meter charge, applicable to ST customers that don't own their meters, are:
- the portion of Wholesale meter costs in the OEB Cost Allocation model (USoA account 1820-3) which were allocated to ST ($891,958), and
- the portion of LV meter costs in the OEB Cost Allocation model (USoA account 1860-3) which were allocated to ST ($1,477,014).
Hydro One's view is that these costs, ($2,368,972), divided by the number of ST meters which Hydro One Networks owns, produce a cost-justified meter charge.

Hydro One has used the same approach as the OEB Cost Allocation Model, which takes fixed costs, including meter costs, and divides the amount by the total number of customers in a class, (Input Sheet 6). In the case of the ST class, many customers own their meters, therefore, these customers should not be charged the meter charge. When Hydro one derived the meter charge, it excluded all customers that own their meters.

c. Yes, Current G3 and F3 customers that are going to be included in the ST class will be charged the meter charge if they do not own the meter. The bill impact of such customers over a representative size range is shown below:

Monthly kW	Meter Charge as % of total bill	Impact (Change in total bill over existing total bill)	Existing customer class
560	4%	(22.5%)	G3
698	3%	(21.8%)	F3
718	2%	(17.2%)	G3
1,049	2%	(23.0%)	G3
1,480	2%	(26.7%)	G3
2,305	1%	(19.8%)	G3
4,735	1%	(22.8%)	G3

Ontario Energy Board (Board Staff) INTERROGATORY #147 List 1

Interrogatory

Ref: Exhibit G2 / Tab 94 / Schedule 1 / p. 3/ Issues 7.3

a. Would embedded distributors be required to pay the Wholesale Market Service Rate of $0.0052 per kWh to Hydro One, if the distributor is a market participant? If so, would this be a pass-through of revenue from a similar rate in their tariffs, or would it be additional to that revenue?
b. Would embedded distributors be required to pay the Rural or Remote Rate Protection Rate of $0.001 per kWh to Hydro One? If so, would this charge be a pass-through of revenue from a similar rate in their tariffs, or would the charge be additional to that revenue?
c. Would embedded distributors be required to pay the Standard Supply Service Administration Charge of $0.25 per month to Hydro One? If so, would this be a single charge or based on the number of customers in the distributor?

Response

a. For any of the distribution supply points which the embedded distributor chooses to be a market participant, the embedded distributor will not be charged the wholesale market service rate. On the other hand, embedded distributors, who choose not to participate in the IESO market for their Hydro One embedded distribution delivery points, would be billed the wholesale market service rate. Hydro One assumes that this would be an additional pass-through cost for the embedded distributor that the embedded distributor would recover from its customers.

b. For any of the distribution supply points which the embedded distributor chooses to be a market participant, the embedded distributor will not be charged the rural or remote rate protection rate. On the other hand, embedded customers, who choose not to participate in the IESO market for their Hydro One embedded distribution delivery points, would be billed the rural or remote rate protection rate. Hydro One assumes that this would be an additional pass-through cost for the embedded distributor that the embedded distributor would recover from its customer.

c. Under the new ST rate class, for any of the distribution supply points which the embedded distributor chooses to be a market participant, the embedded distributor will not be charged the standard supply administration charge. On the other hand, embedded customers, who choose not to participate in the IESO market for their Hydro One embedded distribution delivery points, would be billed the standard supply administration charge. It would be a single charge of $0.25 per month per account and it would not be based on the number of customers in the distributor.

Ontario Energy Board (Board Staff) INTERROGATORY #148 List 1

Interrogatory

Ref: Exhibit G1 / Tab 7 / Schedule 1 / Table 4/ Issues 7.3
For customers currently in the F1 class, there is a very large differential impact depending upon whether they are mapped into the Gse or GSd class, i.e. a basic distribution bill decrease of 6.5% if they will be energy billed or a 27.3% of 31.6% increase if they will be demand billed?

a. Is the reason for this disparity that F1 customers as a whole have unusually low load factors, compared to other customers in these classes? If not due to their load factor, please explain the reason for the disparate outcome for these customers.
b. If the reason for the disparity is the load factor, please provide information on the sample size or other source of load data, together with an evaluation of the robustness of the load profile.

Response

a. The disparity is not due to the Load Factor of the Single Phase Farms being mapped to the GSe versus the GSd rate classes. In fact, the average Load Factor of the Farms going to GSd is 43% which is very similar to the GSd class average Load Factor of 45%. The main reason for the disparity is that the impacts listed in Exhibit G1, Tab 7, Schedule 1, Table 4 are at very different consumption levels.

   For the Farms mapping to GSe, the impacts are based on 2,000 kWh per month yielding the -6.5% Basic Distribution Bill Impact. While for those mapping to GSd, the consumption level is 43,164 kWh at 133 kWs with a 45% Load Factor resulting in a listed impact of 27.3%. The consumption used for Farms mapped to GSd is based on the average consumption for all customers in the GSd class

   However, if the consumption level for the Farms going to GSd is set at the same level as those going to GSe: 2000 kWh, 6 kWs and 45% Load Factor, the impact is -0.6%. Thus, the main reason for the disparity is the consumption level at which the impacts were calculated.

b. Not applicable since the reason for the disparity is not the Load Factor.

Ontario Energy Board (Board Staff) INTERROGATORY #149List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / Attachment A / pp. 35-37, and Exhibit G2 / Tab 5 / Schedule 1 / pages 13 and 18/ Issues 7.3

a. Please describe the circumstances in which a customer in the DGen class would pay the proposed service charge of $36.66 per month per p. 13, and the circumstances in which the customer would pay the proposed Standby Administration Charge of $440 per month per p. 18, either instead of or in addition to the service charge.
b. Are the revenues and costs associated with the Standard Administration Charge included in the cost allocation study, and if so are they shown in column 12 with the DGen class or are they allocated over other classes?

Response

a. The $36.66 monthly charge applies only to customers in the new DGen class, not to customers with Load Displacement generation. The Standby Administration charge of $440 per month applies only to customers with Load Displacement generation. The DGen class includes only customers that are merchant generators, not customers with Load Displacement generation. DGen customers require Hydro One to supply station service power only when their generators are out of service.

b. The revenues and costs associated with the Standard Administration charge are incremental revenues and costs that are not included in the Cost Allocation Study. Hydro One does not expect to collect any revenues in 2008 from the application of this charge. If Hydro One collects any revenues, it will be tracked separately and will be credited back to customers in the future. This is described in Exhibit E3, Tab 1, Schedule 1, page 7, lines 3 to 17.

Ontario Energy Board (Board Staff) INTERROGATORY #150 List 1

Interrogatory

Ref: Exhibit G1 / Tab 3 / Schedule 1 / pp 2 &. 4, and Exhibit G2 / Tab 1 / Schedule 1 / Attachment A/ Issues 7.4

Table 2 on p. 4 is titled "Proposed Revenue / Cost Ratio by Customer Class", and the first row is titled "Proposed Revenue Requirement".

a. In order to understand the purpose of Table 2, would a better heading for the first row be "Proposed Revenue"?
b. Given that the chapter section is titled "Target Revenue to Cost Ratio", does the data in row 1, Table 2, refer to a year when target rates are in place, or to an earlier year?
c. Is the revenue shown in the cost allocation model filed as the attachment in Exhibit 2 for the target year?
d. The description preceding Table 1 says that there is a shortfall estimated at $2.5 million per year due to the proposed revenue requirement being less than the revenue requirement in the cost allocation study (Table 1 on p. 2).Is the forecast revenue shortfall referred to on p. 4 due to harmonization with Acquired Distributors, or mitigation of bill impacts, or some other cause(s)?

Response

a. Yes, the row could also be understood to represent Proposed Revenue

b. The data in row 1 refers to the revenues expected to be collected from each customer class each year, not only the year when target rates are in place.

c. The revenue shown in the cost allocation model is the revenue for each year for each class, not only for the target year.

d. The revenue shortfall is due to mitigation of bill impacts to some Acquired Residential customers being mapped to the R1 customer class

Ontario Energy Board (Board Staff) INTERROGATORY #151 List 1

Interrogatory

Ref: Exhibit G1 / Tab 3 / Schedule 1 / pages 2 & 5/ Issues 7.4

a. If available in the pre-filed evidence, please provide a reference to a description of the calculation of the second data column in Table 3 in the referenced schedule, which has the heading "Average Impact, %". If not included in the pre-filed evidence, please provide a description in enough detail about other costs so that parties can understand how moving the ratio for the ST class from the existing ratio 2.35 (Table 1) to 1.15 (Table 3) results in a decrease of only 4.7% in the average impact.
b. Please confirm that the calculation is correct, in showing that moving Streetlighting from a ratio of 0.6 to 0.7 has an impact of 5%, whereas moving Sentinel Lighting from a ratio of 0.62 to 0.7 has an impact of 25%.

Response

a. The "Average Impact, %" in Table 3 is calculated as "change in total bill / total existing bill".

Distribution-related charges that recover the requested distribution revenue requirement are a small percent of the total bill. The total bill includes commodity and RTSR charges that are not related to the distribution revenue requirement. Therefore, a change to the distribution-related revenues results in a correspondingly smaller percentage change in the impact on total bill.

As shown in the Table below, at a Revenue Cost ratio of 2.35 there is an estimated total bill impact of (2.46)%. At a Revenue Cost ratio of 1.15, the estimated total bill impact is (4.71)%.

Changing the Revenue Cost ratio from 2.35 to 1.15 changes the revenue from ST-related charges from $64.2 M to $31.5 M. This change of $32.7 M represents a decrease of 2.25% on total bill.

	Revenue to Cost Ratio = 2.35	Revenue to Cost ratio = 1.15	Change
Rev. from "ST rates" (Note 1)	$ 64.2	$ 31.5	$(32.7)
Rev. from "other rates" (Note 2)	$ 1,354.2	$ 1,354.2	
Proposed Total Est. bill	$ 1,418.4	$ 1,385.7	$(32.7)

Existing Total Est. Bill	$ 1,454.2	$ 1,454.2	
Class impact	(2.46)%	(4.71)%	(2.25)%

NOTES:
(1) "ST rates" include Service and Meter charges, HVDS-high, HVDS-low, LVDS-low, Common Line, Specific Line
(2) "other rates " include Regulatory Asset Recovery, RTSR, commodity, WMSC, RRRP, DRC

b. Yes, the calculation is correct. The reason for the different impacts is due to the differing consumption levels for these two rate classes resulting from the number of connections per account. For a Street Light account, with an average of 20 connections per account, the consumption is 1440 kWh per month with a total bill impact of $8.6 or 5%. A sentinel light account, with usually one connection per account, has a lower monthly consumption of 62 kWh with a total bill impact of $1.80 or 25%.

Ontario Energy Board (Board Staff) INTERROGATORY #152 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / Attachment A / p. 36, last two lines/ Issues 7.4
Please provide a description of the two allocations of external revenue (CWNB and Unique), in sufficient detail that parties can understand why the Sentinel Lighting ratio is so much affected and others are little affected. Which allocator is more valid?

Response

The allocation of Miscellaneous Revenue per the Board Cost Allocation Model default has been labelled CWNB while a more detailed allocation based on individual accounts has been labelled Unique.

The "CWNB" allocation is taken from Line 2 of the Table on page 35 of Attachment A in the referenced Exhibit. The two large components of this balance are USoA 4225 Late Payments and USoA 4235 Miscellaneous Service Revenue. Based on E4 TB Allocation Details, the allocators for these Accounts are LPHA [late payments historical average] and CWNB [customer weighted number of bills], respectively.

Since a large part of Hydro One Distribution Miscellaneous Revenue is comprised of Sentinel Light Revenues [$4,000,000], it was deemed more appropriate to not use the CWNB allocator, but instead develop more appropriate allocators.

The Miscellaneous Revenues are decomposed into their component parts on page 36 of Attachment A and new allocators were chosen with a direct allocation of Sentinel Light revenues to the Sentinel Light class.

Ontario Energy Board (Board Staff) INTERROGATORY #153 List 1

Interrogatory

Ref: Exhibit E3 / Tab 1 / Schedule 1 / pp. 2-3, and Exhibit G2-2-1 / Attachment A / page 4/ Issues 7.4

In the first reference, Table 1 shows Regulated Revenue totalling $31.3 ($M), and Table 2 shows Unregulated Revenues totalling $10.7 ($M). In the second reference, the cost allocation model shows revenue of $42.3 ($M). To assist in understanding how Miscellaneous Revenue is attributed to classes:

a. Is the method of allocating the amounts from Table 1 the same as for the amounts in Table 2? Please describe the method or methods including the underlying rationale.
b. In particular, which sources of revenue, if any, are allocated on the basis of CWNB (weighted number of bills)?
c. Referring the information in the box at the end of p. 36 of the second reference, please provide definitions of the information in the last four lines in sufficient detail so that parties can understand how the concepts are used to calculate a revenue to cost ratio.

Response

a. The Regulated and Unregulated Revenues presented in Exhibit E3, Tab 1, Schedule 1, Table 1 and Table 2 are further decomposed in Exhibit E3, Tab 2, Schedule 1. The accounts at the lower level of delineation have been analyzed to allocate the Revenues collected to the Rate Classes.

The category for which the various accounts of Exhibit E3, Tab 2, Schedule 1, have been grouped, their balances, and the chosen allocator is listed in the following table.

Revenue Categories	**Regulated**	**Unregulated**	**Allocator**
Sentinel Light	4.0		Direct
Late Payment	14.5		LPHA
Collections	5.5		Connects
New Connects / Upgrades		4.0	Connects
Joint Use	6.2	3.3	O&M
Other	1.1	3.4	O&M
Totals [$M]	31.3	10.7	

b. None of the Miscellaneous Revenues categories have been allocated based on CWNB [customer weighted number of bills].

c. The last four lines of the O1 Revenue to Cost Ratios have been re-stated below with definitions:

- **Line 1**: Allocated costs based on Allocation External Revenues
  - This is the Cost Model Allocated Cost less the default Miscellaneous Revenue plus the Unique Allocated Miscellaneous Revenue
- **Line 2**: CREV+Unique Allocation of Misc External Revenue
  - This is the sum of existing class revenue [CREV] plus the Unique Allocated Miscellaneous Revenue
- **Line 3:** Rev to Cost Ratio – External Rev CWNB Allocation
  - The Revenue to Cost Ratio as calculated by the Cost Model based on Miscellaneous Revenues allocated by CWNB and LPHA
- **Line 4**: Rev to Cost Ratio - External Rev Unique Allocation
  - The Revenue to Cost Ratio based on Line 2 divided by Line 1

Ontario Energy Board (Board Staff) INTERROGATORY #154 List 1

Interrogatory

Ref: Exhibit G1 / Tab 2 / Schedule 5 / Table 2 (page 6), and Exhibit G2 / Tab 2 / Schedule 1 / Table 6 (page 11) / Issues 7.7

a. Please confirm that Table 2 'Development of Harmonized Group Rates for the Residential Urban Customer Class' contains illustrative numbers only. For example, the table shows target rates of $9.45 per month and 0.89 ¢/kWh, whereas the target rates in the first line of the table in the second reference. would be $14.32 per month and 2.29 ¢/kWh.
b. The footnote to the table in the first reference says that the volumetric charge is designed to ensure recovery of the revenue requirement from the group. Does this footnote continue to apply to the proposed rate design? If so, does this apply to the rate year 2008, or to a future year when harmonization is complete?

Response

a. Yes, Table 2 data reflect illustrative examples.

b. The footnote continues to apply to the proposed rate design. In every year of the four year proposed phase-in period, the volumetric charge is determined in such a way that it recovers the remainder of the revenue requirement for each customer class, after the fixed charges have been determined.

Ontario Energy Board (Board Staff) INTERROGATORY #155 List 1

Interrogatory

Ref: Exhibit G1 / Tab 8 / Schedule 1 Table 1/ Issues 7.7
The first two data columns of the table show proposed target distribution rates for each class. The third and fourth data columns show the proposed 2008 rates, described as "mitigated" rates, and are repeated in Exhibit G2 / Tab 5 / Schedule 1 'Rates for Retail Distribution Service. Is it Hydro One's intention to charge the target rates to the Legacy customers as soon as possible, or to phase them in equal amounts over four years (as described in point # 4 above the table)?

Response

It is Hydro One's intention to charge the target rates to the Legacy customers shown in Table 1 in year four of the four year phase-in proposal, with the exception of DGen customers who will be charged the target rates in 2008 for the reason described in the response to Board interrogatory Exhibit H, Tab 1, Schedule 158. The target rates are being phased-in over four years to allow Hydro One to mitigate bill impacts to Acquired customers and to recover the revenue allocated to each customer class in all years. As a result of impact mitigation, the phase in over four years is not in equal amounts.

Ontario Energy Board (Board Staff) INTERROGATORY #156 List 1

Interrogatory

Ref: Exhibit G2 / Tab 5 / Schedule 1 / pp. 3-4, and Schedule 6/ Issues 7.8
Were alternative density zone definitions, or additional density zones, along with more numerous customer classes, considered as a means of lessening customer bill impacts? If so, please describe the alternatives and why they were not proposed in this application.

Response

As stated in Exhibit G1, Tab 2, Schedule 3, Page 1, lines 24 to 26, Hydro One increased its originally proposed number of customer classes from 10 to 12 by proposing new Urban General Service classes for energy and demand billed customers in response to feedback received from Stakeholders.

No alternative density zone definitions or additional density zones where considered as a means of lessening customer bill impacts. The criteria considered for the new 12 customer classes were to reduce the number of customer classes and reflect cost causality. Hydro One is of the opinion that its proposed four year phase-in approach properly addresses customer bill impacts without necessitating the creation of additional customer classes.

Ontario Energy Board (Board Staff) INTERROGATORY #157 List 1

Interrogatory

Ref: Exhibit G1 / Tab 8 / Schedule 1 / p. 1/ Issues 7.8

The general pattern for total bill impact mitigation is described in bullet # 1 for Legacy customers, and is described as a maximum of 10% in 2008, 8% in 2009 and 7% in 2010, with the possibility of additional increases due to the Incentive Rate Mechanism in the latter two years.

a. Which Legacy customer classes or parts of classes are expected to experience bill impacts at or near the 8% limit in 2009, if any? Where in the pre-filed evidence is this information most readily found?
b. Which Legacy customer classes or parts of classes are expected to experience bill impacts at or near the 7% limit in 2010, if any?

Response

a. and b. Most Legacy customer classes or parts of classes have impacts well below 8% in 2009 and 7% in 2010, with the exception of some Unmetered Scattered Load customers. Most of the Legacy Unmetered Scattered Load accounts are in the single-phase General Service class (3,622 accounts) and the impacts in 2009 for these accounts is a bill reduction of 4.3% and in 2010 it is a bill reduction of 4.5%. Unmetered Scattered Load connections currently classified as three-phase General Service (14 accounts) and Urban General Service (392 accounts) will have impacts higher than 8% in 2009 and 7% in 2010. The reason for the higher impact is the low current service charge per connection being charged now to these accounts.

Detailed impacts for 2009 and 2010 were not included in the pre-filed evidence, but bill impacts associated with getting to the target rates are provided in Table 4 of Exhibit G1, Tab 7, Schedule 1.

Ontario Energy Board (Board Staff) INTERROGATORY #158 List 1

Interrogatory

Ref: Exhibit G2 / Tab 5 / Schedule 6/ Issues 7.8
The final column of the table shows the % impact on the total bill for various customers in each rate class. In certain instances, the impact is higher than 10%, such as GSe customers located in Erin, at p. 44, or those near 10% such as those in Fenelon Falls on the same page.

a. Please explain the criterion for when an impact of over 10% would indicate the need for further mitigation (ie lower 2008 distribution rates), and when an impact over 10% is left unmitigated.
b. The total bill impacts for some DGen customers are in the range of 40-50% at p. 96 of the reference. If the impact criterion is different for customers in the Distributed Generation (DGen) class, please explain the difference.
c. If total bill impacts are included for ST customers in the pre-filed evidence, please provide the reference. If not, please provide illustrative impacts on the various customers listed in Exhibit G1 / Tab 2 / Schedule 3 / Table 8.

Response

a. Hydro One applied impact limitation thresholds to customer classes based on average consumption. For Residential customers, 1,000 kWh per month was used and for General Service energy billed customers, 2,000 kWh per month consumption was used. These two levels reflect the average consumption for Hydro One Residential and General Service energy billed customers. At the average level of consumption, total bill impacts were limited to 10% in 2008, 8% in 2009 and 7 % in 2010. This approach is consistent with the approach used by Hydro One in its 2006 EDR submission. Customers with different levels of consumption could see different percentage bill impacts than the thresholds, depending on what the level of the current and proposed rates are for them.

b. For DGen, Hydro One is showing the impacts at different levels of load factors. The last row for each customer class for DGen reflects the impact based on the average consumption for each class. As stated in Exhibit G1, Tab 8, Schedule 1, page 3, lines 23 to 26, the majority of customers in the DGen class would see bill decreases. For DGen customers that would see bill increases, the increase is approximately $25 per month or less. Because most of the DGen customers benefit from being mapped to the new class, Hydro One is not proposing to phase-in customers to the new rates. Hydro One is proposing to charge these customers in 2008 the target distribution rates.

c. The estimated bill impacts to the various groups of customers being mapped to the new ST class can be found in Exhibit G1, Tab 7, Schedule 3, page 2, Table 1.

Ontario Energy Board (Board Staff) INTERROGATORY #159 List 1

Interrogatory

Ref: Exhibit G1 / Tab 6 / Schedule 1 / p. 3/ Issues 7.9

a. The method for establishing the billing demand for ST customers is described as "each customer's coincident peak with the IESO billing time per month per their transmission delivery point". Is this method a change from the existing method for any (or all) customers in the proposed ST class? If so, please describe the existing method and the effect of the change.

b. Is the method of allocating wholesale transmission costs to the customers of Acquired distributors in this application a change from the existing method? If so, please describe the existing and proposed methods, together with a description of how parties can determine the effect of the change on ST, Legacy and Acquired customers using the impact calculations in Exhibit G2 / Tab 5 / Schedules 5 and/or 6.

Response

a. This is a change only for the non-Directs and LDCs which are now being mapped to the ST class. The existing method for these new ST customers was that they were apportioned their share to the IESO's transmission bill on a TS by TS basis and the residual was allocated to Retail for recovery per Rate Class where these new ST customers resided. Hourly interval data exists for Directs and LDCs that enables Hydro One to do this calculation

   The effect of including these former Retail and Acquired customers in the ST Class is that a greater matching of incurred costs is achieved resulting in a smaller pooling of the residual costs to Retail for recovery.

b. The Retail Transmission Service Rates [RTSR] for the customers of the Acquired distributors were the default rates proposed by the OEB upon Market Opening. Hydro One's understanding is that these default RTSR rates were an average of those distributors that filed according to the process outlined in Chapter 11 of the Rates Handbook. Except for Acquired customers mapped to the new ST rate class (as described in a.), the Acquired customers' RTSR rates continue to be based on the existing method outlined in Chapter 11 guidelines, except that actual calculated values are used instead of default values currently in use.

Ontario Energy Board (Board Staff) INTERROGATORY #160 List 1

Interrogatory

Ref: Exhibit G2 / Tab 4 / Schedule 1 / pages 3-5/ Issues 7.9
In order to gain a better understanding of the various RTSRs to ST and other customers, such as the proposed Network charges of $2.01 per kW to ST (Subtransmission customers) customers compared to $1.11 per kW to GSd (General Service demand-billed) customers:

a. Please provide the calculation of Network cost 'Equation 11.3(a)' for the two classes: ST and GSd.
b. If the input amount for Class Monthly Demand of the ST class in Equation 11.3(a) is different from the Charge Determinant amount 38,272,898 kW in the table in section 4.1 on page 5, please provide an explanation of how the two amounts are related to each other.
c. If the input amount for Class Monthly Demand of the GSd class in Equation 11.3(a) is different from the Charge Determinant amount 11,691,631 kW in the table in section 4.2 on page 5, please provide an explanation of how the two amounts are related to each other.
d. Please repeat parts (b) and (c) for Connection cost 'Equation 11.3(b)'.
e. Please clarify whether any ST customers will pay only $0.50 per kW for Connection costs, or whether they will all pay either $1.38 or $1.88 per kW.

Response

a. The Network Cost Pool allocated to the ST class does not employ Equation 11.3(a) of Chapter 11 of the Rates Handbook. Per Section 11.3.2.2, "… ***distributors are encouraged to develop their own estimate***…", Hydro One allocated a better estimate of the IESO charges to the ST customers than Equation 11.3a would allow.

Since the ST customers are interval metered and customer connectivity to the Transmission delivery points exists, a direct allocation of the projected IESO Transmission Costs per Transmission Delivery Point was made to the connected ST customer based on their Coincident demand with the IESO charge time.

Equation 11.3a was used only to allocate the residual Network Cost Pool to the Retail Classes:

• For GSd Network Cost Pool	$	89,327,746
• GSd Tx Coincident Class MWs		5,010
• Total Classes Tx Coincident MWs		34,602
• Allocated Network Cost Pool	$	12,932,797

b. The two amounts are not different.

c. The two amounts are not different.

d. The Connection Cost Pool allocated to the ST class does not employ Equation 11.3(b) of Chapter 11 of the Rates Handbook. Per Section 11.3.2.2, "… ***distributors are encouraged to develop their own estimate***…", Hydro One allocated a better estimate of the IESO charges to the ST customers than Equation 11.3b would allow.

Since the ST customers are interval metered and customer connectivity to the Transmission delivery points exists, a direct allocation of the projected IESO Transmission Costs per Transmission Delivery Point was made to the connected ST customer based on their Coincident demand with the IESO charge time.

Equation 11.3b was used only to allocate the residual Connection Cost Pools to the Retail Classes:

• For GSd Connection Cost Pools	$	83,586,766
• GSd Dx Coincident Class MWs		5,010
• Total Classes Dx Coincident MWs		34,602
• Allocated Connection Cost Pool	$	11,639,498

e. Based on a ST customer's connectivity to Hydro One Distribution assets the following charges will apply:

a) If use only a Line Connection	$0.50 per kW
b) If use only a Transformer Connection	$1.38 per kW
c) If use both a Line and Transformation Connection	$1.88 per kW

Ontario Energy Board (Board Staff) INTERROGATORY #161 List 1

Interrogatory

Ref: Exhibit G1 / Tab 7 / Schedule 2 / pp. 4 - 8/ Issues 7.9
Table 1 shows bill impacts on various customer classes of acquired distributors. The third column of data for each customer class shows the total bill impact including rate riders and the fourth column shows the same plus RTSR.

a. To calculate the impact (%) in the third column, is the cost of RTSR held constant at the existing level, or is it assumed to be $0?
b. The effect of adding RTSR to the Residential class impact appears to be fairly constant at -0.4% or -0.5%, except for Terrace Bay. Please provide a brief description of why the effect of adding RTSR has the opposite and much larger effect for Terrace Bay than in the usual case.
c. In most of the Acquired Distributors, the effect of adding RTSR changes onto the other changes in rates and rate riders is a decrease of approximately 0.3 – 0.4%, to the General Class < 50 kW a decrease of approximately 2 - 3%, and adding RTSR to the General Class > 50 kW a decrease of approximately 4 - 5%. Please explain this differential effect of RTSRs on the respective classes in these distributors.

Response

a. The % impacts in the third column per Rate Class assumes the RTSR rates are held at their existing levels.

b. Currently Terrace Bay's Transmission Delivery points are not levied any Retail Transmission Connection charges by Hydro One and as a result, its customers have a zero RTSR Connection rate. By Harmonizing Terrace Bay with Legacy customers, all customers are pooled and pay both the Network and Connection RTSR rates. This results in the larger impact to Terrace Bay as compared to the other Acquired Distributors.

c. The current RSTR charges for the Acquired Distributors are the default values proposed by the OEB upon Market Opening The differential effect is the result of the difference between the proposed RTSR and the current default values for the Residential, General Service energy billed and General Service demand billed customer classes.

Ontario Energy Board (Board Staff) INTERROGATORY #162 List 1

Interrogatory

Ref: Exhibit G1 / Tab 6 / Schedule 1 / p. 5/ Issues 7.9

The Urban General Service RTSR demand rates are considerably higher than those for General Service: Network $1.41 per kW versus $1.11, Connection $1.27 per kW versus $1.00. Please describe the basis for this difference, including the sources of separate load data if applicable.

Response

The Rate Classes UGd and GSd were allocated their share of the IESO Transmission Charges less ST's share based on Equation 11.3a plus Equation 11.3b of Chapter 11 of the Distributor Handbook.

Based on the Load Profiles for these two classes, they are allocated their share of Transmission Costs. The reduced rate for the GSd class as compared to the UGd class is because the GSd customer class includes larger customers, with lower load factors, and more diversity than the UGd customer class.

The average GSd customer is approximately 190 kWs per month while the average UGd customer is approximately 140 kWs per month.

Ontario Energy Board (Board Staff) INTERROGATORY #163 List 1

Interrogatory

Ref: Exhibit G2 / Tab 4 / Schedule 1 / p. 5, and Exhibit G2 / Tab 94 / Schedule 1 / p. 3/ Issues 7.9

The ST class rates calculated at Tab 4 are Network $2.01 per kW, Line Connection $0.50 per kW, and Connection Transformation $1.38 per kW. The rates quoted at Tab 94 are each $0.01 per kW higher. Which is correct?

Response

An updated page 3 of 8 of Exhibit G2, Tab 94, Schedule 1, was filed on February 20, 2008 that corrects the typos in this page and now provides rates that are consistent in the two documents.

Pollution Probe (PP) INTERROGATORY #1 List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref. A/Tab 14/Sch 3

Please state Hydro One's actual annual electricity demand (MW and MWh) for each year from 2000 to 2007 inclusive.

Response

The requested information is provided below:

Hydro One's Actual Annual Electricity Demand

Year	Energy Purchases (MWh)	Peak (MW)
2000	40,599,854	7,127
2001	40,219,011	7,051
2002	41,564,491	7,264
2003	40,806,867	7,333
2004	41,293,205	7,496
2005	40,838,112	7,191
2006	39,957,319	6,791
2007	40,464,096	6,883

Note. Figures prior to market opening (May 2002) are estimates.

Pollution Probe (PP) INTERROGATORY #2 List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref. A/Tab 14/Sch 3

Please state Hydro One's forecasted annual electricity demand (MW and MWh) for 2008.

Response

The requested information is provided below:

Hydro One's Forecasted Annual Electricity Demand

Year	Energy Purchases (MWh)	Peak (MW)
2008	40,665,719	6,923

Pollution Probe (PP) INTERROGATORY #3 List 1

Interrogatory

Issue Number: 1.7
Issue: Are the proposed Distribution Loss Factors appropriate?

Ref. G1/Tab 10/Sch 1

Please state Hydro One's actual distribution losses in MWh and as a percentage of its electricity purchases for each year from 2000 to 2007 inclusive.

Response

As stated in Exhibit A, Tab 15, Schedule 3, page 1, line 18, it is not economic to measure losses directly for Hydro One Networks' distribution system. As such, actual distribution line losses are not available.

Pollution Probe (PP) INTERROGATORY #4 List 1

Interrogatory

Issue Number: 1.7
Issue: Are the proposed Distribution Loss Factors appropriate?

Ref. G1/Tab 10/Sch 1

For 2008, please state Hydro One's aggregate system-wide:

a) forecasted distribution losses (MWh); and

b) distribution loss factor.

Response

a) Using the OEB approved loss factors, the forecasted aggregate system-wide distribution losses for Hydro One in 2008 are 2,254,666 MWh.

b) The aggregate system-wide distribution loss factor in 2008, determined as a percentage of electricity purchases, is 5.5%.

Pollution Probe (PP) INTERROGATORY #5 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

For each of Hydro One's 2005 CDM programmes, please state:

a) its forecasted and actual savings (MW and MWh); and

b) its forecasted and actual budget.

Response

a) and b) For 2005, HONI spent $4M of rate funded (MARR) CDM.

Since there was no regulatory requirement for forecasted information, annual forecasted savings and annual forecasted budgets were not developed. Instead of managing by year, HONI managed by program and targeted keeping within the approved 3rd tranche of the MARR total funding envelope. The actual savings (MW and MWh) and the actual expenditures for Hydro One's 2005 CDM programmes are shown below (for more details, refer to Figure 1 on page 5 of the 2005 CDM Annual Report filed with the OEB on March 31, 2006 available online at http://www.oeb.gov.on.ca/documents/cases/RP-2004-0203/annualreports/h1Network.pdf).

Figure 1

PROGRAM	3 YEAR BUDGET ($K)	SPENDING TO DEC 2005 ($K)	ANNUAL SAVINGS KW	ANNUAL SAVINGS kWh	LIFECYCLE SAVINGS kWh	LIFECYCLE $/kWh
Residential						
Smart Meters	7,800	519				
Real Time Monitoring Pilot	425	467	38	401,482	2,007,410	0.23
Real Time Monitoring Program	1,400					
Mass Market Coupon Initiative	1,500	277	285	7,261,874	70,142,678	0.004
LED	430	171		219,079	6,572,370	0.026
Low Income/Social Housing	5,000	46				
Load Control Pilot	1,220	783	358			
Load Control Program	3,500	0				
Energy Audits/Analysis	230	0				
Total	21,505	2,263	681	7,882,435	78,722,458	0.012
Commercial/Industrial, Farm, MUSH						
Interim Time of Use	475	238				
C/I MUSH Conservation	600	261				
C/I & Farm Load Control	3,500	0				
Farm Energy Efficiency	750	110				
Total	5,325	609	0	0	0	0
Common						
Distribution Loss Reduction	8,000	0				
Program Management and Research	3,700	804				
Communication and Education	1,000	305		286,578	1,146,312	0.266
Carrying Charge		25		n/a		
Total	12,700	1,134	0	286,578	1,146,312	0
Grand Total	39,530	4,006	681	8,169,013	79,868,770	0.021

Pollution Probe (PP) INTERROGATORY #6 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1-page 8

For each of Hydro One's 2006 CDM programmes, please state:

a) its forecasted and actual savings (MW and MWh); and

b) its forecasted and actual budget.

Response

a) and b) For 2006, HONI spent $16.4M of rate funded (MARR) CDM (which is the Life to Date (LTD) spending for 2006 of $20.4M from Figure 1 below less the $4.0M shown in the response to Exhibit H, Tab 2, Schedule 5).

Since there was no regulatory requirement for forecasted information, annual forecasted savings and annual forecasted budgets were not developed. Instead of managing by year, HONI managed by program and targeted keeping within the approved 3rd tranche of the MARR total funding envelope. The actual savings (MW and MWh) and the actual expenditures for Hydro One's 2006 CDM programmes are shown below (for more details, refer to Figure 1 on page 5 of the 2006 CDM Annual Report filed with the OEB on April 2, 2007 available online at http://www.oeb.gov.on.ca/documents/cases/RP-2004-0203/2006-annualreports/hydroonenetwork.pdf).

Figure 1

PROGRAM	3 YEAR BUDGET ($K)*	LTD SPENDING TO DEC 2006 ($K)	Cumulative SAVINGS KW**	Cumulative ANNUAL SAVINGS kWh**	Cumulative LIFECYCLE SAVINGS kWh
Residential					
Smart Meters	7,800	7,800	-	-	-
Real Time Monitoring Pilot	425	466	38	401,482	2,007,410
Real Time Monitoring Program	4,075	3,242	3,357	14,809,145	74,047,076
Mass Markets	1,870	1,382	4,671	81,724,679	526,034,109
LED	380	296	-	546,454	16,393,624
Low Income/Social Housing	4,400	497	6	294,078	5,263,750
Load Control Pilot	710	710	358	-	-
Load Control Program	3,500	2,117	2,169	806,435	8,780,648
Total	23,160	16,510	10,599	98,582,273	632,526,617
Commercial/Industrial, Farm, MUSH					
Interim Time of Use	920	632		-	-
C/I MUSH Conservation	600	240	21	185,396	1,870,103
C/I & Farm Load Control	3,500	2		-	-
Farm Energy Efficiency	750	114	9	64,000	408,009
Total	5,770	988	30	249,396	2,278,112
Common					
Distribution Loss Reduction	7,200	877		-	-
Program Management and Research	2,600	1,576			
Communication and Education	800	463	-	286,578	1,146,312
Carrying Charge		25		-	-
Total	10,600	2,941	-	286,578	1,146,312
Grand Total	39,530	20,438	10,629	99,118,247	635,951,041

*Note: The budget has been reallocated from approved plan and the reallocations are within the 20% flexibility allowed by the Board. The new allocation has already been provided to the Board in the 2006 Q4 report.
**Cumulative annual and lifecycle KW and KWh savings are reported as per calculations in Appendices B.

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Pollution Probe (PP) INTERROGATORY #7 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

For each of the Hydro One's 2007 CDM programmes, please state:

a) its forecasted and actual savings (MW and MWh); and

b) its forecasted and actual budget.

Response

a) and b) For 2007, HONI spent $17.8M of rate funded (MARR) CDM (which is the Life to Date (LTD) spending for 2007 of $38.2M from Figure 1 shown in the response to Exhibit H, Tab 2, Schedule 7 of $20.4M). In 2007, HONI also spent $7.6M of rate funded (Global Adjustment Mechanism) CDM delivering core programs under contract with OPA.

Since there was no regulatory requirement for forecasted information, annual forecasted savings and annual forecasted budgets were not developed. Instead of managing by year, HONI managed by program and targeted keeping within the approved 3rd tranche of the MARR funding envelope. The actual savings (MW and MWh) and the actual expenditures for Hydro One's 2007 CDM programmes are shown below. Hydro One's 2007 CDM Annual Report is provided as an Attachment A to this response.

MARR Funded programs

Figure 1

PROGRAM	3 YEAR BUDGET ($K)*	LTD SPENDING TO DEC 2007 ($K)	Cumulative SAVINGS KW**	Cumulative ANNUAL SAVINGS kWh**	Cumulative LIFECYCLE SAVINGS kWh
Residential					
Smart Meters	7,800	7,800	-	-	-
Real Time Monitoring Pilot	470	466	38	401,482	2,007,410
Real Time Monitoring Program	5,085	5,082	4,767	22,946,131	114,732,007
Mass Markets	2,465	2,465	5,854	98,915,451	635,802,470
LED	430	424	-	546,454	16,393,624
Low Income/Social Housing	3,200	3,163	879	8,373,080	115,751,166
Load Control Pilot	710	710	358		
Load Control Program	4,660	4,536	13,198	4,113,097	48,811,867
Energy Audit Analysis	215	213	-	-	-
Total	25,035	24,859	25,095	135,295,696	933,498,544
Commercial/Industrial, Farm, MUSH					
Interim Time of Use	1,130	997	-	-	-
C/I MUSH Conservation	1,040	948	2,011	14,503,166	210,511,025
C/I & Load Control	2,390	2,339	33,773	108,854,220	108,898,068
Farm Energy Efficiency & Farm Load control	510	458	349	1,970,695	17,454,329
Total	5,070	4,742	36,132	125,328,081	336,863,422
Common					
Distribution Loss Reduction	6,175	5,399	2,362	7,207,655	144,153,108
Program Management and Research	2,500	2,425	43	396,185	3,248,037
Communication and Education	765	744	140	3,649,933	30,145,133
Carrying Charge		25		-	-
Total	9,440	8,593	2,545	11,253,773	177,546,278
Grand Total	39,545	38,194	63,771	271,877,550	1,447,908,244

Note: *The budget has been reallocated from approved plan and the reallocations are within the 20% flexibility allowed by the Board.
** Cumulative annual and lifecycle KW and KWh savings are reported as per calculations in Appendices B.

In addition to its MARR funded programs, in 2007 Hydro One delivered the four OPA core LDC programs.

YEAR 2007 - OPA programs	Initial estimate of spending for 2007 Program Schedules[1,2]	ACTUAL SPENDING TO DEC 2007 ($)[2]
SummerSavings	$ 6,000,000	$ 4,683,915
Electricity Retrofit Incentive Program (ERIP)	$ 875,000	$ 119,471
Great Refrigerator Roundup	$ 675,000	$ 69,937
PeakSaver	$ 3,500,000	$ 2,690,556
TOTAL	**$ 11,050,000**	**$ 7,563,879**

[1] Funding for the 2007 Program Schedules has been extended into 2008
[2] Forecast and actual spending include payment of incentives to customers for SummerSavings, ERIP and PeakSaver. ERIP incentives will be paid throughout 2008, as projects are completed

Hydro One Networks Inc.

Conservation and Demand Management Plan

Annual Report to December 31, 2007

RP-2004-0203 \ EB-2005-0198

March 31, 2008

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Introduction

On February 18, 2005 Hydro One Networks Inc. (Networks) received final approval from the Board for their Conservation and Demand Management Plan (CDM Plan) covering the period 2005 – 2007, for $39.5 million.

The approval was conditional upon the re-allocation to other projects of $7.1 million that Networks planned for smart meters in 2006. On November 1, 2005 the Board approved the re-allocation of the funds. The CDM Plan included Market Adjusted Rate of Return (MARR) funding in the amount of $39.5 million. The initiatives approved by the Board satisfy the Minister's condition of a financial commitment to reinvest in CDM initiatives. In the decision of the Board, Networks, along with all other LDCs, was required to file both quarterly and annual reports tracking the progress of the CDM Plans. This report meets the requirement for the annual report for 2006.

On October 5, 2004, the Board issued a *Procedural Order*, which contained the reporting filing requirements (paragraphs 26 through 30) applicable to MARR CDM funding. On December 21, 2005 the Board issued the *Guideline* for Annual Reporting to the OEB, which is intended to include reporting for funding for the year ended 2005 and the third tranche MARR. On March 31, 2006 Networks submitted its first CDM Annual Report.

On October 2, 2006 the Board issued a revised TRC Guide. On March 1, 2007 changes to the reporting format were released which included a new schedule (Schedule C) and revisions to the existing schedules. On March 9, 2007 clarification regarding the schedules was also released. The second Annual report was submitted on April 2, 2007.

On May 22, 2007 the Board approved the extension of the deadline to complete CDM activities from September 30, 2007 to April 30, 2008.

On March 3, 2008 confirmation was received that the 2007 Annual Report guidelines had not changed from the 2006 report. In this third CDM Annual Report, Networks has complied with the requirement of the Procedural Order. Networks has also provided the information requested in the Guidelines.

Results Summary

Networks has been successful at managing and rolling out programs across all sectors, including residential, farm, commercial and industrial, as well as the Municipalities Universities Schools and Hospital (MUSH) sector. Networks has worked with partners from the retail sector, as well as with community-based organizations, schools and governmental bodies for the successful delivery of the Conservation and Demand Management programs and management of existing / prospective participants in various initiatives. The cooperation with other Local Distribution Companies has been a valuable strategy for the development and delivery of joint programs to all electricity customers. The portfolio of programs offered confirms the Company's commitment to contribute to the goal of culture change within the province through various communication and education activities.

Results achieved to date amount to annual energy savings of 272 million kWh. This is the equivalent of the electricity needed to power almost 23,000 homes for one year, or 178,000 tonnes of CO_2 emission reductions.
The expected energy savings over the lifetime of the equipment are just under 1.5 billion kWh. This translates to the electricity consumption of 121,000 homes for one year, or 950,000 tonnes of CO_2 emission reductions.
In addition, a summer peak demand reduction of 64 MW has been achieved.

Networks' CDM Plan was successfully implemented in 2007 to provide a balanced approach to both conservation and load control initiatives. Our programs offered opportunities for all customers within our service territory to contribute to and benefit from a culture of conservation. As mentioned in the 2005 and 2006 CDM Annual Reports, Networks' challenges are that it must cover most of the geography of the province, yet it only serves about 25% of the customers, a fact that is reflected in cost effectiveness of some individual programs. Networks' programs delivered financial savings for our customers, as well as kilowatt hour (kWh) and kilowatt (kW) savings to contribute to meeting the Province's goals.

The following figure provides an overview of Networks' CDM approved budget, life to date (LTD) spending as at December 31, 2007, as well as kWh and KW savings earned.

Figure 1: Summary of spending

PROGRAM	3 YEAR BUDGET ($K)*	LTD SPENDING TO DEC 2007 ($K)	Cumulative SAVINGS KW**	Cumulative ANNUAL SAVINGS kWh**	Cumulative LIFECYCLE SAVINGS kWh
Residential					
Smart Meters	7,800	7,800	-	-	-
Real Time Monitoring Pilot	470	466	38	401,482	2,007,410
Real Time Monitoring Program	5,085	5,082	4,767	22,946,131	114,732,007
Mass Markets	2,465	2,465	5,854	98,915,451	635,802,470
LED	430	424	-	546,454	16,393,624
Low Income/Social Housing	3,200	3,163	879	8,373,080	115,751,166
Load Control Pilot	710	710	358		
Load Control Program	4,660	4,536	13,198	4,113,097	48,811,867
Energy Audit Analysis	215	213	-	-	-
Total	25,035	24,859	25,094	135,295,696	933,498,544
Commercial/Industrial, Farm, MUSH					
Interim Time of Use	1,130	997	-	-	-
C/I MUSH Conservation	1,040	948	2,011	14,503,166	210,511,025
C/I & Load Control	2,390	2,339	33,773	108,854,220	108,898,068
Farm Energy Efficiency & Farm Load control	510	458	349	1,970,695	17,454,329
Total	5,070	4,742	36,132	125,328,081	336,863,422
Common					
Distribution Loss Reduction	6,175	5,399	2,362	7,207,655	144,153,108
Program Management and Research	2,500	2,425	43	396,185	3,248,037
Communication and Education	765	744	140	3,649,933	30,145,133
Carrying Charge		25		-	-
Total	9,440	8,593	2,545	11,253,773	177,546,278
Grand Total	39,545	38,194	63,771	271,877,550	1,447,908,244

Note: *The budget has been reallocated from approved plan and the reallocations are within the 20% flexibility allowed by the Board.

** Cumulative annual and lifecycle KW and KWh savings are reported as per calculations in Appendices B.

As of year-end 2007, 97% of the 3rd tranche MARR budget had been spent. For the few programs not totally completed in 2007, approval was received from the OEB to operate these programs until April 2008. During 2007 Networks spent 45% of the triennial budget. This reflected Hydro One's strategy to:

- concentrate on pilot programs in 2005 in order to evaluate customer acceptance and effectiveness of new technologies.
- roll out larger scale programs in 2006, including in-home displays, residential load control, appliance pickup, residential coupon programs, social housing, low income and the first phase of smart meters.
- In 2007, expand programs that operate successfully, complete programs such as social housing and low income, while adding a few new programs (eg. online audits).

Transition of three programs to similar OPA programs also occurred, primarily in the third quarter (appliance pickup, residential load control, and the commercial /industrial conservation program).

Highlights for 2007:

- The CDM program portfolio to date has produced over $3.40 of societal benefits for every $1 spent on program costs, as measured through the Total Resource Cost (TRC) test. Net TRC benefits of $88 million have been produced.
- Participation in Networks' CDM programs reached almost 1.2 million life-to-date.
- Real-time monitors were installed in over 31,000 homes – the largest deployment in North America. This product also won Blueline Innovations and Networks an award for best new energy efficient technology deployment from the Association of Energy Service Professionals (AESP).
- Customers' response to the Residential Load Control Program (SmartStat) continued to show a strong performance throughout 2007. Enrolment reached the target of 10,000 participants on schedule in June, 2007.
    - Hydro One initiated two successful load control events in July and August during the hottest days of the summer, reducing peak demand by up to 13 MW.
- Double Return program was launched in the winter of 2007 as a new demand response initiative targeted at Commercial/Industrial distribution-connected customers.
    - This program exceeded expectations by achieving 38MW in winter peak reduction and 33MW in the summer.
- Hydro One customers purchased 242,000 energy efficient products during the Spring Every Kilowatt Counts program.
- The Appliance Pickup program was very successful, attracting bookings in 2007 for over 7,200 operating refrigerators, freezers and room air conditioners and leading to expansion of the program from eastern Ontario to all of southern Ontario. The LTD program total reached 11,300 units.
- By the end of 2007, energy retrofits had been conducted for 112 Social Housing providers, representing over 5,500 housing units within Networks' territory.
- The PowerSaver Business Incentive program provided funding of over $420,000 to more than 110 business and farm customers. The average incentive released was approximately $4,000.
- An online audit was launched to allow residential and small business customers to understand their electricity usage and learn ways they can reduce their consumption

Program Overviews

Residential: Residential In-Home Display Program

The largest full scale deployment of real time in-home displays in North America, provided 31,000 Hydro One's residential customers in Northern Ontario with real time feedback on their actual electricity use and cost, thereby enhancing their ability to conserve.

Description:
During 2007, Networks completed its Residential In-Home Display Program by providing over 31,000 real-time monitor (RTM) units to residential customers in Northern Ontario. Customers used the Monitors to view and manage their electrical consumption in real-time. They were able to view their current usage rate and cumulative consumption in kWh, as well as an estimate of the cost of that consumption. Networks' initiative was the largest of its kind in North America.

Design:
Following the completion and evaluation of the pilot project in 2005, Hydro One decided to implement a full scale roll out of in-home displays in Northern Ontario.

During 2006 and 2007, Networks offered in-home display units to its 130,000 residential customers in Northern Ontario, on a "first come, first served" basis. Over 31,000 customers took up Network's offer. Eligible customers received the $150 in-home display units for free, but paid handling costs of $8.99 plus taxes.

Intent:
The objectives of the program were to provide a real-time feedback device to empower residential customers with the information needed to change behaviours and encourage efficiency. As reported in Networks 2005 annual report, an average of 6.5% decrease in electricity consumption was experienced by customers in the pilot.

Delivery:
All aspects other than program evaluation were awarded to BlueLine Innovations as part of a turn key contract following a competitive proposal process, including product supply, marketing, customer enrolment, product delivery and customer/product support.

Customers could order the product from BlueLine via a 1-800 number or from their website. BlueLine also held a number of community events across Northern Ontario where they demonstrated the unit and had stock available for customers to purchase.

Evaluation:
The program was launched in July 2006 and by May 2007 approximately 31,000 monitors had been delivered to Networks customers. Those customers, representing about 20% of the residential customers in Northern Ontario, are now equipped with in-home displays for their electricity consumption.

Networks staff is sample testing customer changes in electricity usage based on meter readings in 2007- 2008.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings KW	Cumulative Lifecycle kWh
Real Time Monitoring Pilot	466	401,402	38	2,007,410
Res. In-Home Display Program (30,950 participants)	5,082	22,946,131	4,767	114,732,007

Residential: Residential In-Home Display Program - First Nations

Based on the successful roll out of over 31,000 monitors to residential customers, Networks initiated the largest In-Home Display roll out for First Nations communities in North America.

Description:
During Fall 2007, Networks initiated the First Nations In-Home Display Program by providing real-time monitors to customers living in Northern Ontario First Nation communities at no cost.

Design:
After the major In-Home display campaign Networks found that First Nations communities had a lower uptake in monitor orders (only 5% penetration compared to the 20% achieved during the full scale deployment in Northern Ontario). Therefore, in consultation with First Nation stakeholders, Networks launched a new campaign targeting specifically those communities. As the $8.99 shipping costs appeared to be the main cause for not receiving orders from First Nations customers, Networks decided to incur the shipping expenses as well as the cost of the in-home display unit, therefore offering monitors to First Nations at zero cost.

Intent:
The objectives of the program were to provide a real-time feedback device to empower First Nations customers with the information needed to change behaviours and encourage efficiency.

Delivery:

Several Organizations - including Blueline, Ontario First Nation Technical Services Corporation and Seven Generations - were key for the successful delivery of the program.

Customers ordered the product from BlueLine via fax to the Ontario First Nation Technical Services Corporation or from the BlueLine website. Blueline also provided a toll-free telephone number for enrolling in the In –Home display First Nations program. Networks also held a number of community demonstrations across Northern Ontario with the help of local residents in Northern Ontario First Nations and key organizations that work with First Nation communities.

Evaluation:

The campaign will close in the first quarter of 2008, and the preliminary results show the final uptake to be in line with the results of the major campaign. Close to 400 customers have participated by ordering a real-time monitor.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings KW	Cumulative Lifecycle kWh
Res. In-Home Display Program - First Nations (400 participants)	70	297,761	52	1,488,601

Residential: Residential Load Control Program (Smartstat)

Customers' response to the Residential Load Control program remained strong throughout 2007. Installations reached the target of 10,000 participants on schedule in June, 2007, allowing Hydro One to initiate two separate load control events in July and August, during the hottest days of the summer, reducing peak demand by up to 13 MW.

Description:
The Smartstat residential load control program was launched in July, 2006 with an initial target of 6,000 participants which was subsequently increased to 10,000 in 2007. This program was designed to achieve up to 13 MW summer peak demand reduction by controlling participants' central air-conditioning (AC) units using web-enabled programmable thermostats, and by cycling electric water heater loads using an off/on switch.

The program offered a top-of-the line programmable thermostat including free installation and programming for all eligible participants. With this thermostat Hydro One controls customers' central AC units to reduce peak summer load on the system. The customer, meanwhile, can benefit by saving energy throughout the year and have the ability to remotely change the temperature settings via the internet. In cases where the customer had an electric hot water system, a load control switch was also be installed plus an energy saving tank wrap and pipe insulation for additional energy savings. Finally, all participants received two free energy efficient CFLs upon installation of the thermostat. No cash incentives were offered in this program.

Design:
Load control is carried out through an event which involves increasing the air conditioning temperature set-point by two degrees Celsius in summer afternoons for four hours at minimal or no inconvenience to the home owner. The customer cannot override the event manually but can opt out of the event or the program by calling a toll free number to make their wishes known. During our first load control in July 2007, out of 10,000 participants 6 customers requested to opt out of the event with none choosing to leave the program. Our experience is consistent with those in other jurisdictions where opting out is a rare event.

Hydro One's load control strategy is as follows:

- Control Season: June 15 to September 15
- Control Events: 5-10 events /summer season
- AC control event duration: 4 hours (2:00-6:00 pm)
- DHW control event duration: 3 hours maximum (3:00-6:00pm)
- Air conditioning control Increase temperature by max 2 degrees C
- DHW control Switch off up to 3 hours during AC control
- Control on weekends & holidays None

Currently, the load control events are initiated in response to IESO public appeal for peak load curtailment in the hottest days of the summer.

Intent:
The program's target of 10,000 installations was met on schedule in June, 2007, providing Hydro One with up to 13MW of peak load control capacity. Hydro One exceeded the target in

terms of enrolments, reaching 12,000 customer requests to enrol in the program by June 2007.Thus Hydro One completed an additional 2,000 installations funded through Global Adjustment Mechanism under contract with OPA.

Owning a central AC was a pre-requisite for participation in the program. As a result of the program all program participants are now equipped with smart thermostats that are ready to receive a command during a control event. In the high peak days of the summer, Hydro One will take control of the thermostats remotely and setback the temperature by two degrees Celsius, reducing load by approximately 1 kW per household. If the homeowners happen to have an electric water heater, the load reduction will be in excess of 1.5 kW per customer.

Delivery:
The program management was out-sourced as a turnkey service to Goodcents Solutions. The vendor was accountable to Hydro One for the promotion, customer enrolment, deployment, equipment installation, call center management, customer care, and maintenance of the system for up to three years

The installation of the thermostats and the water heater switch devices were carried out by dedicated full time contractors trained and specifically assigned to the program. The installation of the equipment was only a component of what the installers were responsible for. They were required to encourage the home owner to view a DVD describing the program objectives and explaining the technologies involved and why their participation was important. This contributed to creating a culture of conservation as one of the key objectives of this program. The thermostat was also programmed by the installer for the first time based on the customer's instructions and a package was left behind including further information as well as two energy saving compact fluorescent light bulbs.

Evaluation:
Program installation progress was tracked and reported on a weekly basis. As described above, Hydro One directly initiates the load control events determining the duration and timing of the load reduction on the system. To verify the results, a professional monitoring and evaluation analysis was also undertaken to determine the load reduction impact as well as the corresponding customer response and satisfaction level.

Program	LTD Spending to Dec 2007 ($)	Cumulative Annual Savings kWh	Cumulative Annual Savings KW	Cumulative Lifecycle kWh
Residential Load Control (SmartStat) (10,000 installations)	4,536	4,113,097	13,198	48,811,867
Residential Load Control Pilot (416 homes)	710	0	358	0

Residential: Cold Shoulder Appliance Pickup

Customers reacted very positively to this initiative and enrolled over 11,000 inefficient secondary fridges, freezers and room air conditioners for pick up and proper disposal.

Description:
The Cold Shoulder Appliance Pickup program, which launched in September 2006, provided customers with free in-home pickup of secondary, operating refrigerators, freezers and room air conditioners. The appliances were permanently removed from operation and disposed of in an environmentally responsible manner.

Design
This program was designed to retire old secondary operating appliances and provide customers with an energy efficient pack that includes educational material plus some energy efficient products, such as compact fluorescent lights (CFLs) and a timer. Networks targeted the customers through bill inserts, bill messaging, web page, newspaper and radio advertising.

Intent
The intent of the program was to reduce energy consumption and demand, save customers money on their electricity bills, increase customer understanding of the benefits of energy efficiency, and increase the usage of other energy efficiency technologies (eg. CFLs and timers).

Delivery
All aspects of the program, other than program marketing, are delivered through a turn key contract with the service provider, including customer enrolment, scheduling appointments, picking up and transporting the appliances, decommissioning and proper disposal. Networks planned and delivered an integrated marketing campaign to raise awareness of this initiative, utilizing bill inserts, bill messages, website, radio and newspaper advertisements.

Evaluation
Customer response was very favourable for this program, exceeding the targeted enrolment and leading to expansion of the program territory from Eastern Ontario to all of southern Ontario. Total participation reached 11,300 units.

The majority of participating customers indicated that they had learned about the program through either the bill insert or bill message, with newspaper advertising also generating significant enrolments.

The program was closed in July 2007 when the OPA's Great Refrigerator Roundup program became operational across the province.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Appliance Pickup (11,300 units)	1,426	16,194,283	3,095	133,466,659

Residential: Every Kilowatt Counts

1.2 million energy efficient products were purchased with coupons in Spring 2007, of which over 240,000 were purchased by Networks' customers.

Description:
In 2006, the OPA assumed responsibility for the residential coupon initiative developed and implemented by Networks and the CLD in 2005. LDC participation increased to 80 in 2006 from the initial 27 and made available to all Ontario retailers, with over 3,000 stores taking part. Through this campaign Networks customers in Ontario received educational material on energy saving together with coupons for the purchase of energy efficient equipment.
In 2007 only the Spring campaign involved the use of third tranche MARR funds and thus only Spring results are reported.

Design
The Spring 2007 campaign ran from April 16 to June 17, 2007. Educational booklets were sent to all residential customers along with coupons for related energy efficient products that could be redeemed at retail outlets across the province. Products promoted included : compact fluorescent lights, outdoor motion sensors, ceiling fans, outdoor solar lights, dimmer switches and furnace filters.

Intent:
The objectives of this program were:

- Provide homeowners and tenants with brochures on how to easily save energy in their home or apartment;
- Provide incentives to homeowners and tenants to purchase on one or more of the easy-to-do products identified in the campaign
- Achieve savings in terms of kWh and kW

Delivery:
Networks was actively involved in co-promoting the campaigns, providing direct mail data for its customers base to the OPA for addressing of the coupon books and co-branding them to encourage customer participation. Networks also advertised the program in newspaper ads, on its website, and produced bill messages to customers to promote the program.

Evaluation:
Results for the coupon program continued to be robust in Spring 2007, with products purchased totalling just under 1.2 million across the province. Networks estimates that approximately 20% of the coupons redeemed were for products purchased by its customers (or 242,000 products). The OPA evaluation report on this program is not yet available and thus OPA costs and load impacts for two products are unknown, therefore kWh are likely understated.

Program	LTD Spending to Dec. 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Every kW Counts (969,000 products)	212	75,044,621	1,215	443,927,250

Residential: PowerSaverPlus Online Audits

Over 4,000 customers took the self-administered Online Energy Audit program and received recommendations on how they could lower their usage and electricity bill.

Description:
Networks launched a self administered online energy audit in the fall of 2007. Two energy audit applications (branded Business PowerSaverPlus and Home PowerSaverPlus) were made available to Hydro One small- and medium-sized general service customers as well as residential and small farm customers.

Design:
Approximately one million Hydro One customers will be able to participate in the program and get online audit recommendations to make their homes and businesses more energy efficient.

Intent:
The PowerSaverPlus program was launched to provide customers with an assessment of their electricity usage and give recommendations on how they can lower their usage and electricity bill.

Delivery:
Aclara Software (formerly Nexus Energy Software), a leading service provider in North America, was competitively selected to provide the energy audit services for one year.

Evaluation:
The online audit program was launched in September 2007 and by December 31, 2007 over 4,000 customers had participated in the audits.

Residential: Low Income Program - CMHC / NRCan

Up to $3,000 was available to low income home owners for energy efficient upgrades and retrofits.

Description:
Networks was offering up to $3,000 to qualifying low income households to be used towards upgrades and retrofits to the home designed to achieve electrical energy savings. These funds were to be used in conjunction with the funds and services that were available from Canada Mortgage and Housing Corporation's (CMHC) Homeowner Residential Rehabilitation Assistance Program (RRAP) and Natural Resources Canada's (NRCan) EnerGuide for Houses Program. Combining the three programs was intended to help achieve maximum energy savings in low-income households in Networks' service territory and create synergies in the administration of the program. This was the first program of its kind in Canada, and was the first to bring the EnerGuide for Houses program to the low-income sector. Unfortunately, in May 2006 following a change in federal government, the EnerGuide for Houses program was cancelled. The arrangement remained intact for the 46 homes that had already received an EnerGuide audit but no further houses were eligible.

Design:
CMHC processed applicants through their RRAP program, which included criteria to determine low-income status. Qualifying applicants then received a health and safety assessment of their home, as well as an EnerGuide for Houses energy audit to determine the energy efficiency of their home. RRAP funding for health and safety retrofits was offered to the qualifying applicant and Networks' funds were used for energy improvements identified in the EnerGuide audit.

Networks funded the electricity improvements up to $3,000 per home. NRCan funded the EnerGuide for Houses audits, one before and one after improvements were implemented, valued at $300 - $500 total.
CMHC processed applications, including screening for adherence to low income criteria, and handled all correspondence with the customer. RRAP did not fund energy efficiency improvements.

Intent:
The objective of this program was to assist low income homeowners in contributing to and benefiting from conservation. Low income customers tend to have a higher prevalence of electric water heating and electric heating in their homes and they spend proportionately more of their disposable income on energy costs. Low Income customers also have fewer means to improve the efficiency of their homes and would not otherwise have had access to the EnerGuide for Houses program.

Delivery:
All aspects of the program were delivered under the RRAP structure. Vehicles used to promote the program included various social agencies and municipal and provincial government agencies dealing with social and housing issues. Networks also directed customers with payment issues to the program.

Evaluation:

Negotiations took place between January 2005 and September 2005, with the program launch in September 2005. Reaching the target audience and getting them to come forward was a challenge as this was a group not easily defined or self identified. Forty-six applications had been received by the time the EnerGuide for Houses program was cancelled. Of those, under 30 customers had their pre-retrofit audit, 14 of whom completed their retrofits and received their payments in 2006 while the final 10 customers completed their retrofits in 2007.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Lifecycle kWh
Low Income Program – CMHC / NRCan (24 customers)	71	177,185	4,429,625

Residential: Low Income Program - Retrofits

Leverage the OPA's Low Income Pilot to undertake extended measures in Hydro One Networks Territory.

Description:
The Ontario Power Authority (OPA) conducted a Low Income program Request for Proposals (RFP) in 2006. Five bids were received and evaluated. Envirocentre and Green Communities (the Vendors) were awarded contracts to deliver low income audit and retrofit pilots in several areas across the province, all of which encompassed or abutted portions of Hydro One's service territory. Hydro One reached agreements with each party and with the OPA to ensure that a significant number of Hydro One customers would be included in the pilot and that Hydro One would pay for the installation of extended measures.

Design:
With Hydro One covering the cost of extended measures (e.g. insulation) for its customers with electric heat (plus some basic measures and audits not covered by the OPA), the OPA was able to direct more of their pilot budget towards infrastructure development. The Vendors coordinated all work on behalf on Hydro One and the OPA and billed the appropriate party for relevant work.

Intent:
The objective of this program is to assist low income homeowners in contributing to and benefiting from conservation. Low income customers tend to have a higher prevalence of electric water heating and electric heating in their homes and they spend proportionately more of their disposable income on energy costs. Low Income customers also have fewer means to improve the efficiency of their homes and would not otherwise be in a position to undertake retrofits of this nature.

Delivery:
All aspects of the program are delivered by the Vendors. The Vendors worked with government agencies, municipalities, food banks, etc. to identify individuals and areas of low income and to contact potential eligible customers.

Hydro One screened customers for suspected electric heat and the Vendors compared those locations with known low income areas. In some cases Hydro One advised customers of the program via a bill message. Networks also directed customers within the eligibility areas with payment issues to the program.

The Vendors screened customers for eligibility (income level, electric heat, etc.), conducted the audits and coordinated installation of all basic and extended measures.

Evaluation:

A total of 259 customers received energy efficient retrofits from Hydro One under the Low Income Retrofit Program. While Hydro One and the OPA had separate contracts with the Vendors, the sharing of vendors, processes, measures, infrastructure, etc. was very beneficial in reducing the costs and extending the reach of the program.

The most difficult part of the Low Income Program was identifying and recruiting customers. One method tried was for Hydro One to screen customer consumption records and identify areas where electric heat appeared to be prevalent. A direct mail marketing piece directed to these areas resulted in 102 participants, producing by far the best results of the methods utilized.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Low Income Program - Retrofits (259 customers)	364	709,439	97	11,350,915

Residential: Low Income – First Nations Retrofits

This initiative leverages work already performed for Natural Resources Canada (NRCan) to undertake cost effective electricity efficiency retrofits in First Nations communities.

Description:
Under the EnerGuide for Houses Program, The Abor Group had been retained by NRCan to perform audits on First Nations housing. Prior to the cancellation of the EnerGuide for Houses Program, Abor had completed "A" audits (pre-retrofit) on over 400 houses for which no "B" audits (post-retrofit) had been done since funds were lacking to undertake the identified measures. An assessment of these audits identified 55 electrically heated homes in 6 communities that required cost effective thermal envelope retrofits. The Abor Group was retained to retrofit the identified houses with thermal envelope and basic conservation measures and to do the same for any other houses identified as requiring those measures while they were in each community doing the work.

Design:
The design of the program was to take advantage of the audits that had already been conducted and paid for under the EnerGuide for Houses program, thereby directing more of Hydro One's funds towards actual measures. Thermal envelope measures (attic insulation, basement insulation, air sealing, and programmable thermostats where warranted) were the primary focus, but basic measures (water tank wrap, pipe wrap, and CFLs) were also installed while in the home. 55 previously identified houses formed the backbone for the program, with other homes added while in the community. In all, 125 houses received some conservation measures.

Intent:
The objective of the program was to lower the disproportionate energy burden faced by the First Nation community and address some of the known issues identified by the EnerGuide for Houses Program. This objective was also in line with the Ministerial Directive to reduce energy consumption in low income housing.

Delivery:
The Abor Group, who had conducted the original audits for NRCan and had established a working relationship in the subject communities was contracted to deliver all aspects of the program.

Evaluation:
Leveraging the existing EnerGuide for Houses “A” audits allowed a number of communities to be identified where sufficient known retrofits were necessary to justify, on a TRC basis, the outlay for travel and accommodation required to undertake a retrofit program in those communities. While in those communities additional cost effective retrofits were identified and undertaken. Basic measures undertaken resulted in annual savings of more than 170,000 kWh, while thermal envelope measures contributed annual savings of more than 530,000 kWh.

The current avoided cost factors do not place any value on winter peak demand reductions nor on environmental or other indirect benefits. It is important that avoided costs be kept up to date so that positive savings opportunities are not forgone.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings KW	Cumulative Lifecycle kWh
Low Income – First Nations Retrofits (125 homes)	128	708,063	2	13,596,532

Residential: Low Income – First Nations Pilot

Establishes a viable approach to the delivery of electricity efficiency retrofits and education in First Nations communities.

Description:
The First Nations Energy Conservation Project provided an integrated approach to energy conservation at the Chippewas of Georgina Island First Nation reserve, encompassing conservation education and housing retrofits. The Chippewas of Georgina Island First Nation was selected for the pilot program due to the community's location (York Region) and its demonstrated knowledge and receptiveness to issues of conservation and renewable energy. In this community, Hydro One identified a total of 91 homes eligible for this program. Hydro One assigned the delivery of the program (audit, effectiveness studies and retrofit) to Windfall Ecology.

Design:
The goal of this pilot program was to assess and improve the energy efficiency of the entire community. The First Nation Energy Conservation Project was comprehensive, addressing appliances, hot water, lighting, building envelope, and heating systems. The delivery process consisted of 3 phases with an education component running throughout the duration of the project:
Phase I – Auditing and installation of basic energy conservation measures;
Phase II – Installation of extended energy conservation measures;
Phase III – Verification and evaluation

All houses in the community were to be provided with education, basic energy efficiency measures and a home energy efficiency audit. The audit data for electrically heated homes was assessed with a TRC evaluation tool developed by the Program Manager, Windfall Ecology Centre, in cooperation with Green Communities Canada, to determine if extended measure retrofits were justified.

Intent:
The objective of the program was to lower the disproportionate energy burden faced by the First Nation community and pilot a community approach. This objective was also in line with the Ministerial Directive to reduce energy consumption in low income housing.

Delivery:
Windfall Ecology Centre, who had worked with the community over a period of time, was contracted to deliver all aspects of the program. The cancellation of EnerGuide for Houses caused some delay while Windfall pursued alternative audit funding. The OPA came on board to fund the audit portion and to expand the educational component of the program.

Evaluation:
There were ninety-one houses belonging to the Chippewas of Georgina Island First Nation. Seventy homes received the basic energy conservation measures and a home energy efficiency audit, eleven houses had been abandoned due to their poor condition and ten residents declined to participate. The basic measures, including compact fluorescent light bulbs, water heater pipe wrap, low flow showerheads and faucet aerators contribute an average annual savings of 256 kWh/year from each home. Fifteen electrically heated homes benefited from extended conservation measures aimed at the building envelope (attic/basement/crawl space insulation and comprehensive air sealing).

As a result of both the basic measures and the retrofits, a 5% reduction in community electricity usage was achieved. Retrofits accounted for 79% of total savings and basic measures 21%.

Retrofits for a number of houses did not quite pass TRC. The IPSP identifies a number of additional factors that are not reflected in the current avoided cost factors, which also do not place any value on winter peak demand reductions. Adjustments to the avoided costs to reflect the IPSP may result in these retrofits passing TRC. It is important that avoided costs be kept up to date so that positive savings opportunities are not forgone.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings KW	Cumulative Lifecycle kWh
Low Income – First Nations Pilot (70 homes)	64	173,783	3	2,209,686

Residential: Social Housing Program

The Social Housing Program is an effective tool in significantly reducing energy costs of operating social housing building stock and educating tenants in the wise use of energy. Hydro One led the way in this innovative program, with over 5000 homes in over 100 buildings participating.

***Des*cription:**
This program built on the success of the Social Housing Pilot Program launched in 2005. That pilot program consisted of three social housing providers in Networks' service territory, representing 811 housing units that participated in a program to improve the energy efficiency of their buildings. Networks contributed a total of $550 per unit. The pilot program funding included $50 per housing unit towards energy audits and up to $500 per housing unit for the implementation of measures designed to achieve electrical energy savings ($450 per housing unit), as well as energy awareness training ($50 per housing unit). The pilot program was well received by the participating housing providers. Only minor administrative changes were required for the full program that was rolled out across the province in 2006. This program, called The Green Light Initiative, was part of the Social Housing Services Corporation's (SHSC) Energy Management Program. Program participants had an on-site energy audit conducted and used these findings to generate an energy management plan for their buildings. SHSC reviewed the plans and then developed a funding plan for the properties' retrofit, utilizing both public and private funding. The social housing property managers and their respective boards approved the energy improvement plan and the energy efficiency measures were implemented.

Intent:
The objective of this program was to assist social housing providers to increase the energy efficiency in their housing stock resulting in lower electricity bills, which for the most part are paid by the housing providers. Social housing properties tended to be older and often lack the funding to pursue measures to improve their energy efficiency.

Delivery:
Housing Providers received an on-site energy audit. The results of the audit were made available to the property managers to use in the development of an energy management plan. This plan had to be approved by their municipalities or boards before it was presented to the SHSC. The SHSC developed a plan to secure various funding partners in order for the retrofits to proceed. Networks offered up to $550 per unit for social housing properties in Networks' service territory.

Evaluation:
This program hit full stride in 2007 as the program gained momentum in the social housing sector. The final results exceeded all expectations as 112 buildings represented 5,626 housing units enrolled in the program. This exceeded the initial projection of 4,500 housing units enrolling into the program. A total of 96 buildings, representing 5,040 housing units, underwent retrofits and implemented a combined total of 22,000 energy efficiency measures. The recommended energy saving measures varied from items such as the accelerated purchase of energy efficient refrigerators and the installation of energy efficient lighting in common areas to the installation of programmable thermostats in individual units. There

were also some innovative solutions such as the installation of an exterior solar wall to offset building heating costs or implementation of control strategies in order to maximize energy efficiency in a building.

The program accomplished 6.3 million annual kWh and 83 million lifecycle kWh savings; these results were achieved primarily in 2007.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Social Housing (5,626 participants)	2,476	6,316,850	722	82,675,807

Residential: Time-of-Use Pilot Project

411 customers participated in the time-of-use (TOU) pilot project. Pilot participants responded to the regulated pricing plan (RPP) TOU rates and were able to shift and conserve part of their load. For a typical pilot customer on the RPP TOU rates, the load-shifting impact was approximately 3.7% and conservation impact averaged 3.3%. For the customers on RPP TOU rates with Real Time Monitors, the conservation impact increased to 7.6%

Description:
Networks undertook a pilot project involving about 411 residential and farm customers for 5 months (May to September 2007). The pilot project assessed the response of customers to RPP TOU commodity rates versus the conventional RPP (non-TOU) commodity rates. Customers' actual electricity bills were based on differential rates where commodity costs differed during peak, mid peak and off peak hours.

Design:
The pilot consisted of 411 customers with the following groupings:

- 153 customers on RPP TOU rates with real-time in-home display monitors (RTM);
- 177 customers on RPP TOU rates with a $50 incentive at the end of the pilot;
- 81 customers on regular RPP rates with RTM;

In addition, 75 customers on regular RPP rates were used as control group without RTM or incentives.
Customers on TOU rates received their bills based on these TOU rates.

Intent:
The main objectives of the pilot were:

- To assess the customer responses to RPP TOU rates versus the conventional RPP rates. Responsiveness is measured in the following categories:
    - shifting usage away from peak periods in kWh;
    - conservation impact; consumption decrease in kWh;
    - bill impact, savings in $.
- To assess the effectiveness of the RTM in conjunction with RPP TOU rates;
- To assess the communication and settlement support required for implementing RPP TOU rates.

Delivery:
All aspects of the pilot were handled by Hydro One staff. Because TOU rates have not yet been implemented at Hydro One, monthly electricity bills were produced manually by Vertex.

Evaluation:
Major findings of this pilot are summarized below:

- Pilot participants responded to the RPP TOU rates and were able to shift and conserve part of their load. For a typical pilot customer on RPP TOU rates, the load-shifting impact approximated 3.7% and conservation impact averaged 3.3%.
- Providing RTMs to customers on RPP TOU rates helped them to respond even more. On a normal summer's day, the load-shifting impact averaged 5.5% while the conservation impact averaged 7.6%. On a hot summers day (over 30°C), the load-shifting impact was even more pronounced at 8.5%.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings KW	Cumulative Lifecycle kWh
TOU Pilot project (411 participants)	72	396,185	17	3,248,037

Residential: Seasonal LED Light Exchange

Residential customers responded to the Seasonal Light Exchange in all parts of the province. The numbers speak for themselves: over 115 community events and over 32,000 LED strings of light retired.

Description:
This program was intended to operate as a 2 year program – 2005 and 2006 and therefore did not operate in 2007. The program was delivered in three components: The first component was a SLED exchange, where customers exchanged incandescent light strings for a SLED string at Hydro One attended events. These typically larger events were, for the most part, well attended and were staffed by Hydro One staff and/or an outsourced event management firm.

The second phase consisted of communities self enrolling through a web based enrolment process. Individual communities that used the online application process described their event that they intended to hold and provided such details as the anticipated attendance. Initial expectations were that approximately 30 to 40 individual events would be enrolled through this process. In total almost 100 communities responded. Advertising funds were made available to the enrolled communities to assist with promotion of their events. These exchanges were community managed whereby event organizers leveraged their own festivals and events in order to obtain maximum customer participation.

The third component was a program in which SLEDs were given to municipalities for their community Christmas trees and other seasonal decorations, to replace their existing incandescent decorations. By far the largest event was providing lights to Canada's largest Christmas tree that was erected in Cobden, Renfrew County. This was a very high profile event, which received national television coverage. It was also attended by dignitaries such as the Prime Minister. A part of this third component also included the sponsorship of Owen Sound's Festival of Northern Lights, which attracts thousands of visitors annually. Funds were provided to increase the efficiency of their existing Christmas displays.

Design:
The design of this program was simple, yet effective. A series of community events were held, at which customers turned in incandescent strings of lights in exchange for a string of SLEDs. The incandescent lights that were collected were taken out of service and recycled in an environmentally friendly manner.

Hydro One also provided energy efficient holiday lights free of charge to any community in our service territory that held its own SLED Exchange. Community participation was obtained through direct marketing to over 250 communities in Hydro One territory.

Due to a Safety Alert related to the manufacturer of the SLEDs that Hydro One utilized for the Exchange Program, retailer gift cards were used as a replacement for the SLEDs at the exchanges in 2006.

Intent:
The objective of the SLED program was to create awareness of the benefits of SLED lights to drive market transformation and to reduce the seasonal electrical load associated with seasonal lights. SLEDs use up to 95% less energy, last longer and emit less heat. These benefits provide both energy savings and cost savings to the customer.

Delivery:

The program was designed to be delivered by Networks, directly to participating communities or alternately delivered by municipalities or community groups themselves. Communities leveraged their own events in the latter approach. This mode of delivery suited the program well, as communities were able to put their own "stamp" on their SLED exchange event.

Evaluation:

Sales figures from as early as the 2005 campaign showed that market transformation was well under way and that utilities were leading the charge.

Exchange Results:

Year	*SLED Distributed*	*Inc. Strings Retired*
2005	10,800	10,800
2006	18,500	21,800
Total	29,300	32,600

In 2006 close to 18,500 SLED strings and gift cards were provided to residential customers and to municipalities. A total of 12,500 incandescent strings were collected directly from customers during the 2006 exchange program. The distribution of gift cards for the purchase of SLEDs also contributed to additional incandescent light strings being retired. In total an estimated 32,000 incandescent light strings have been retired to date by the Networks program. The program did not operate in 2007.

Program	**LTD Spending to Dec 2007 ($K)***	**Cumulative Annual Savings kWh**	**Cumulative Lifecycle kWh**
SLED Lighting (More than 32,000 strings retired)	424	546,454	16,393,624

*In 2007 expenses were incurred that were related to the recall of defective SLEDs at the end of 2006.

Residential: PowerSaver Tour

Over 215,000 people visited the summer festivals across the province where the PowerSaver information booths were held, with 10,000 of those customers responding to a survey and receiving a free compact fluorescent light.

This program was not operational in 2007.

Description:
The PowerSaver Tour program was a joint initiative between Networks and The Home Depot aimed at promoting and achieving energy savings. During ten weeks, from June 2006 until September 2006, a co-branded truck travelled throughout rural Ontario and participated in 11 summer festival events where it displayed educational material and offered discounted energy efficient products for sale. The program was leveraged with another complementary program - Cool Shops, for small businesses.

Design
The program was designed to reach the rural areas of Hydro One territory throughout an integrated and co-branded marketing campaign. The participation of a large retail brand contributed to the delivery of the program and the penetration of a wide base of customers. The delivery of the PowerSaver Tour was done through Summerhill Group to eleven scheduled events during the summer of 2006. Summerhill representatives displayed promotional and educational material and sold discounted energy efficient products. A survey was administered at Tour events in order to understand customers' attitudes towards energy conservation and the effectiveness of this Hydro One program.

Intent:
The main objectives of this integrated mass market campaign were to:

- Promote customer education and contribute to culture change
- Improve the energy efficiency of small businesses and homes within Hydro One Networks rural territory
- Engage, communicate with and have a better understanding of a wide base of Hydro One customers

Delivery:
All aspects of the program were contracted through a turn key contract with an external service provider, who arranged the venues, promoted the booths, managed the survey and handled the supply and sales of all products. The Tour was also supported by a dedicated website. Customers at each event completing the survey were provided a free CFL sample.

Evaluation:
Over 215,000 people visited the PowerSaver information booths at summer festivals. More than 10,000 compact fluorescent lights (CFLs) were given away and just under 14,000 energy efficient products were sold at the PowerSaver information booths.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
PowerSaver Tour (23,969 products)	314	3,170,923	8.2	17,981,316

Residential: Keep Cool

Over 2,000 operational room air conditioners were removed from service and disposed of in an environmentally responsible manner.

This program was not operational in 2007.

Description:
The Keep Cool program was geared to removing old, but operating, room air conditioners (RACs) from service. It was developed by the Clean Air Foundation and run in conjunction with Hydro One and several other utilities in 2006.

Design and Delivery
Networks engaged the Clean Air Foundation to carry out the Keep Cool program under a turn key contract, which ran for three weekends from June 10, 2006 to June 28, 2006. An integrated marketing communication campaign was launched to reach electricity customers in the participating communities and inform them of the timeline for the program. People interested in the program brought their old RACs to one of the participating Home Depot or Home Hardware stores, where Clean Air representatives would collect the old units. After having filled a survey regarding the Keep Cool campaign awareness and cooling preferences, participants were given $25 store gift card.

The program ran in Home Depot stores in York Region (Aurora and Newmarket), Owen Sound and Brockville, and also at 5 Home Hardware stores in eastern Ontario (Smith Falls, Carleton Place, Perth, Kemptville and Almonte).

Intent
The intent of the program was to shave summer peak demand by encouraging customers to retire old and inefficient RACs and by offering $25 retailer gift cards.

Evaluation
Hydro One was successful in promoting the program to its customers. In total, Hydro One retired 2,036 room air conditioners.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Keep Cool (2,036 units returned)	221	1,649,160	2,071	6,596,640

Residential : Communication and Education

Communication and education (C&E) are integral parts of every program delivered by Networks, the costs of which are incorporated into program budgets. In addition to such program specific C&E, Networks also undertakes general awareness C&E on an ongoing basis and a limited number of directed C&E programs. In 2007 Networks appeared at forums, trade shows and community events to discuss conservation and demand management and our programs and provided educational material in various bill related communications. In 2007, directed C&E programs included the SmartPak Initiative, the Turn Out the Light Campaign and grants to education based organizations.

SmartPak Initiative

The initiative was developed in 2006 and was delivered in 2007. The SmartPak Education initiative is a targeted to Grade 5 students as they cover the energy component of the prescribed science curriculum. This initiative encouraged elementary school students and their households to adopt energy conservation practices within Hydro One Networks' service territory.

The SmartPacks, which are backpacks containing energy efficiency measures, such as CFLs, low flow shower heads and LED night lights, supplemented the energy efficiency curriculum being taught in public schools for the fifth grade. The energy efficiency components provided the students with hands-on experience in installing and using the energy- and water-saving devices contained in the kits.

Not only will the SmartPack Program foster a culture of conservation among the students and their families, it will lead to real energy savings in the student's homes (3.1 million kWh in annual energy savings and 27 million kWh energy savings on a lifecycle basis). A total of 6,000 SmartPacks were distributed through 405 teachers located in 260 participating schools.

"Turn Out the Light" Campaign

Networks co-sponsored a 30-second public service announcement that features Nelly Furtado and a small army of children dancing down a school hallway reminding schools and families to conserve electricity by turning off unnecessary lights. The announcement appeared this summer on television stations across the province.

Grants:

Networks provided a grant to the Environmental Earth Angels for the Student Energy Challenge. The program is designed to teach students about their consumption behaviour at school and at home. It demonstrates that simple changes in behaviour can reduce energy

consumption, energy bills and the burning of fossil fuels. The program is directed at Grade 5 students and provides a hands-on teaching module.

Networks also provided a grant to the Simcoe County Board of Education in partnership with several area LDCs. The grant was used for the development of teaching materials for the Grade curriculum and training of Science teachers in the delivery of the Energy modules.

EnviroGirl – TVOKids

In 2006 Hydro One Networks entered a partnership with TVOKids to create a character, EnviroGirl, who is a champion of the environment. There are a series of video shorts on conservation and the environment that will play on the air and are available on the internet, related tip sheets and a multiplayer game. Although this is a corporate sponsorship and not funded from CDM funds, CDM staff consulted with TVOKids on content for all the materials.

Program	LTD Spending to Dec 2007 ($K)*	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Communication and Education (includes 6,000 SmartPaks)	744	3,649,933	140	30,145,133

Commercial/Industrial: PowerSaver Business Incentive Program

*For many, in this customer segment, energy conservation projects take a back seat to the "business" of operating a business. The **PowerSaver Business Incentive Program (PBIP)** brought awareness of the benefits of energy efficiency retrofits to the market place. This program can be characterised as a catalyst for customers to re-prioritize their energy retrofits and proceed with implementing them.*

Description:
This program provided up to $50,000 in financial incentives per customer to all business, institutional and farm customers that undertook energy efficiency retrofits in their facilities. Incentives for technologies such as lighting, motors, cooling equipment and energy efficient transformers were provided to all these customer groups.

Design:
The program consisted of fixed financial incentives for predefined technologies (i.e. prescriptive) such as motors, cooling equipment, lighting technology transformers as well as agri-business equipment. There were also financial incentives for custom projects based on demand reduction. This program was application based and incentives were paid once retrofits were installed and operational. Qualifying customers had to obtain pre-approval for all custom applications. Under the prescriptive project, qualifying customers had the option of applying for rebates after project completion by including proof of purchase and installation with the application form. This design element was intended to influence customer energy efficiency projects that had a very short timeline; where pre-approval was not practical. It also was intended to influence customer equipment purchases that were typically unplanned such as motor replacements. The program underwent some design changes in early 2007 as agricultural technologies were added to enhance the program. In 2007 it was also necessary to increase the incentive level for the Custom portion of the program from $150 per kW to $250 per kW, in order to encourage customers to proceed with more comprehensive items in their facilities.

Intent:
This program addressed the need for a comprehensive CDM program targeted at the commercial, industrial, MUSH and farm sector. Segments within these sectors contained a large potential for energy conservation savings (reduced energy consumption in kilowatt hours). The intent was to promote earlier adoption of energy efficient technologies and influence purchasing decisions for all customers undertaking retrofits of their facilities.

Delivery:
Direct marketing campaigns were utilized to deliver this program to Networks' customers. Media advertising was also used to reach key customer segments. The program was designed to direct all customers to the Networks self-serve website. The interactive website was configured to provide all of the necessary applications and forms the customer required

to complete the application. The site also contained useful tools such as incentive calculators, technical guides, program guideline booklets, presentations and fact sheets.

Other marketing initiatives consisted of running workshops, engaging trade allies, such as electrical distributors, and key channel partners, such as government and industry associations. This was accomplished through face to face meetings with all of the organizations afore-mentioned as well as meeting with key customer groups.

Evaluation:
In 2007 this program gained significant momentum as the majority of applications were completed during the 3rd and 4th quarters of 2007.

Networks customers responded as they submitted approximately 230 applications for projects under this program. A total of185 of these project applications were approved by Networks. In total 117 projects (including farm projects) , encompassing in excess of 30,000 measures were completed by program close.

All sectors participated in the program: Commercial, Industrial, MUSH and Agricultural. The agricultural sector was the largest group participating in PBIP, with 30% of applications coming from that sector, followed by the manufacturing sector with 25% and municipal sector with 13%.

The average incentive provided to customers was $3,800, with farm customers receiving considerably less at $1,650. This was mainly due to the fact that farm customers had considerably reduced project scopes, resulting in the reduced average incentive.

The PowerSaver Business Incentive Program exceeded initial targets as it achieved 13 million kWh in annual energy savings and 195 million kWh energy savings on a lifecycle basis for the business sector. Details for savings from the farm sector are reported on page 52 under the Agricultural programs section.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
PowerSaver Business Incentive Program – Business sector (78 projects completed and paid)	521	12,824,832	1,821	193,695,391

Commercial / MUSH: Toronto Region Conservation Authority Programs

Municipalities, schools and hospitals are looking for innovative ways to reduce costs as they work within very confined budgets. Benchmarking is a good tool to illustrate facility energy consumption.

Description:
Networks participated in four energy initiatives led by the Toronto Region Conservation Authority (TRCA) as part of their Community Transformation Programs. The programs targeted municipalities, hospitals and schools. Bench marking was a common component for all program participants to drive action. The projects in which Networks were involved:

- The Mayor's Megawatt Challenge – identified actions that could be taken to achieve energy savings in municipal buildings and single pad arenas
- Greening Health Care – encouraged hospitals to work together to achieve optimal energy savings
- Sustainable Schools – identified best practices in green design, commissioning and operations, enabling school boards to improve the energy performance of schools
- Archetype Housing Design Competition - this design competition engaged architects, engineers and graduate students from across Canada to design a mass production Green Home for new community development. The scope of the project has grown since its inception with a second, home to be built to the adjacent home. The first home will feature cutting edge energy efficient technology that is currently available. The second home will feature prototype technologies that have not been fully commercialized. The Archetype Housing Design Competition component of this initiative was separate from the components described above and was funded from the education portion of the Hydro One CDM portfolio.

Design:
The majority of the initiatives were comprehensive programs which included initial needs assessments and recommended initiatives to achieve savings, in addition to web-based applications to facilitate independent monitoring and benchmarking of performance to ensure savings were achieved. A key element of the program was the facilitation of information sharing among members so that best practices could be identified.

Intent:
The purpose of Networks involvement in the TRCA programs was to demonstrate support of community-based programs, as well as foster co-operation with municipal local distribution companies.

Delivery:
All elements relating to the delivery of programs was co-ordinated by the TRCA.

Evaluation:

- The Mayor's Megawatt Challenge – one municipality located in Hydro One territory enrolled in the program. Facility assessments were undertaken which resulted in energy efficiency retrofits being implemented. These energy savings were claimed in the PowerSaver Business Incentive Program. Generally participation in this program did not meet expectations. In April of 2007 funding was reallocated to the Greening Healthcare component of this program which gained considerable momentum.
- Greening Health Care – This component of the TRCA initiative performed very well. So much so, that funds from other components of this initiative were channelled to Greening Healthcare thus enabling additional hospital corporations to take part in this initiative. Workshops were held in several regions of the province and a total of 9 hospitals enrolled into Greening Healthcare.
- Sustainable Schools – A total of six schools located in Hydro One territory enrolled in the program. Facility assessments and workshops were delivered to several school boards taking part in the larger program. The results of this initiative were not positive with several schools reporting consumption increases in the short term. This effect is expected to be reversed with continued participation by these schools in the program.
- Archetype Housing Design Competition - A winning design was chosen in June of 2006, which incorporated LEED - Gold and Energy STAR for New Homes environmental ratings. Construction of 2 homes will be completed in 2008. The enlargement of scope of this project to two homes is a direct result of this initiative receiving considerable attention from the energy efficiency sector and the media.

Commercial / MUSH: Municipal Traffic Signal LED Retrofit Pilot & Program

Municipalities have recognized that conversion of their traffic signals to LED technology makes good business sense. Benefits include both reduced electricity consumption as well as reduced maintenance costs.

Design:
LED lights provide significant energy savings and substantially increased life expectancy which reduces overall maintenance costs. Networks provided monetary incentives to a pilot municipality, the City of Owen Sound, which worked with Networks to assess the costs and savings associated with the retrofit of traffic signals from incandescent to LED technology. These costs and savings were used to establish the TRC inputs and the fixed monetary incentives available under the full program.

Intent:
This program was designed to achieve energy conservation savings (reduced energy consumption in kilowatt hours). Currently, municipalities in Hydro One Networks' territory utilize inefficient incandescent traffic signal bulbs on a wide scale. LED signal lights are considerably more efficient, and Hydro One, through this program, provided monetary incentives in order to facilitate earlier adoption of this technology.

Delivery:
The first phase of this program was the execution of a pilot project in Owen Sound. The pilot served to validate the actual savings of retrofitting traffic signals. The program was then offered to all municipalities in Hydro One Networks distribution territory.

Municipalities were able to apply to Hydro One though both traditional applications as well as an online process. Hydro One supported municipalities in making their business case through useful tools such as the online energy savings calculator for traffic lights.

At program close, a total of 30 municipalities had applied to the program. This program was marketed directly to municipalities' thorough direct mail campaigns. Hydro One also promoted this program at relevant conferences and in relevant trade magazines.

Evaluation:
At year end, 16 municipalities with traffic signals had completed their retrofits under the program, saving approximately 1.7 million kWh annually. A total of 1,898 traffic signal components were replaced with LED technologies.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Municipal LED Traffic Light (1,898 traffic signal components)	88	1,678,334	190	16,815,634

Commercial / MUSH: Cool Shops

250 energy efficiency audits were carried out for small business establishments.

This program was not operational in 2007.

Description:
Cool Shops is a program developed by the Clean Air Foundation whereby electrical distribution utilities fund free audits for small businesses in their service territory. Businesses are provided with some complementary energy efficient products (such as CFLs and LED exit sign lights) and the opportunity to order other energy efficient products through a discounted order form (30%-80%, in association with Home Depot).

Design and Delivery
Networks ran Cool Shops in conjunction with the PowerSaver Tour in 2006 as part of a turnkey contract. Tour representatives stopped at small businesses along their route and visited businesses near each event location. Business associations were advised in advance when the representatives would be in their area.

Intent:
The main objectives of this integrated Mass Market campaign were to:

- Promote business customer education and contribute to culture change
- Improve the energy efficiency of small businesses within Hydro One Networks rural territory

Evaluation:
Before the delivery of the program a target of 225 audits was set, and the objective was exceeded.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Cool Shops (250 audits)	42	154,231	8	1,336,522

Industrial: Demand Response Program (Double Return)

This is a unique demand response program that attempts to reduce the system's peak load while at the same time providing customers with a range of behind-the-meter energy efficiency services including on-site visits, technical workshops, and employee engagement tools to raise awareness about conservation benefits. The customers responded exceptionally well to this program. Thus the achieved results, in terms of peak demand reduction at 38MW and 34MW, for winter and summer respectively, exceeded the program targets.

Description:
The Double Return program was launched in November 2006. The objective of the program was to reduce summer and winter peak demand in commercial and industrial facilities by up to 25 MW. The target customer group consisted of approximately 800 interval meter accounts, each with a peak load greater than 200kW but under 5MW. This customer group had an aggregate monthly peak load in excess of 1000 MW. To qualify for incentives, the customers needed to reduce their average peak demand by at least 5% to 10% during winter and/or summer peak months.

Design:
All Hydro One commercial and industrial distribution-connected customers with interval meters were eligible and therefore automatically enrolled in the program. To qualify for incentives, the participants need to achieve a minimum of 5% to a maximum of 10% peak load reduction against the corresponding monthly peak loads in the previous year. The target months in the program were December to February for the heating season and June to August for the summer.

The incentive payments were set equal to double the amount of reduction in distribution charges on the customer's bill resulting from achieving a minimum of 5-10% reduction in their peak load. For every distribution dollar the customer saved by reducing their peak demand, the program provided two dollars in incentive payments (i.e. "save once get paid twice").

The defining characteristic of this initiative was the simplicity of its design. For instance, the eligible customers were automatically enrolled in the program without having to complete an application form. The only demand made on the participants was to ask them to reduce their own peak demand to qualify for incentives. In addition, to make it easier for the customers to set targets and take action, the incentives were calculated based on the actual metered load data without any weather normalization. This was deemed particularly prudent in view of the historical low weather-sensitivity of the target customer group.

Intent:
The program target was to reduce the distribution system peak demand by up to 25 MW in both winter and summer seasons while raising awareness and promoting a culture of conservation.

Delivery:
The unique feature of this demand response program was its heavy emphasis on education and technical assistance to enable customer to reduce their peak demand. The services offered to the participants included a secure webpage for each customer to access their historical load data; free expert site-visits provided on demand; technical workshops; employee engagement kits; and on-line consultations.

The key components of the program (web-site, marketing, workshops, and on-site-visits) were professionally handled by a number of specialized vendors including Summerhill Consulting Group (marketing), Kinectrics Inc. (expert visits and technical audits), Marcom Group Inc. (website development and operations) and Leapfrog Consulting (workshops). Hydro One directly managed program and coordinated the vendor activities.

Evaluation:
The participants' response to the program was exceptional and the results exceeded the program targets by a significant margin. The customers also showed genuine enthusiasm for the behind-the meter services. This program came as a pleasant surprise to many in this customer class which has been traditionally left to their own devices to reduce their energy costs, contributing to overall customer satisfaction.

This is a cost-effective program both in terms of total cost/kW as well as the TRC benefit/cost ratio. The total cost was approximately $70/kW and based on the actual results, the TRC benefit cost ratio was 24.

Program	LTD Spending to Dec 2007 ($)	Cumulative Annual Savings kWh	Cumulative Annual Savings KW	Cumulative Lifecycle kWh
Double Return	2,339	108,854,220	33,773	108,898,068

Industrial: Leamington Demand Response Pilot

This project was initiated in 2005 to provide Hydro One with practical experience in assessing the merits and limitations of integrating distributed generation in our grid which is an emerging challenge for Hydro One. This project makes it possible for commercial and industrial customers to connect existing standby generators to the distribution system to dispatch loads into the market during peak demand. The dispatching and project management is done through an existing local aggregator, GenSet, working directly with the customers and IESO.

Description:
A reliable supply of electricity is critical for most commercial and industrial operations. Thus, the customers have installed significant back-up generation that is currently used only when there is a power system failure. In the Leamington area, a group of customers have made arrangements with a local aggregator (GenSet) to allow existing standby generation to be connected to the distribution system to export power to the electricity grid.

These types of connections are not common in this market due to process and cost barriers and the lack of motivation on the part of the owners of back up generators for whom generation is not their primary business. The generators cannot be net metered as the goal is to sell into the market, it is not renewable generation and the generators are above the size allowable for net metering. As such, the changes required to the farmers' facilities are complicated and costly. GenSet has worked with the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB), the Electrical Safety Authority (ESA) and Hydro One to understand processes and have developed an acceptable connection arrangement and operating infrastructure. As a result, they can offer a standard connection arrangement to minimize the process requirements.

The pilot is a test case enabling the development of a Hydro One *Distributed Generation Strategy of back up facilities*. In addition, with current limitations in the local transmission facilities supplying the area, the project provides an opportunity to assess the practical feasibility of utilizing demand response as an alternative to upgrading transmission infrastructure.

Design:
The GenSet aggregation services provide the participating operators with access to the 10-minute Non-spinning Operating Reserve Market and the corresponding revenues through the sale of energy in the electricity market. The arrangement is to provide an economic demand response by operating back up generation during peak demand for approximately 150 to 200 hours per year. However, the cost of the initial connection set-up is prohibitive to most potential participants. Hydro One supports this initiative by providing incentives equal to 50% of the initial set-up cost for each site up to $50,000 per 1MW of generation connection.

The aggregated generation will operate independently in the Market. Hydro One's support will only help with the investment required for the connection set-up at the generator's site. In return Hydro One will claim the connected facilities and the resulting actual demand reduction

in 2008. The primary benefit of the project, however, is the valuable insight into the merits and limitations of distributed generation and demand response activities.

Intent:
The objective of this project is to assess the merits and limitations of aggregating standby generation power across a number of C/I operations and to successfully dispatch load during peak demand to the power system through IESO. Hydro One provided financial assistance towards the cost of connection set ups in return for gaining practical experience in this area.

Delivery:
GenSet is the aggregator and a turn key project manager for this initiative. The aggregator's responsibilities include the initial recruitment, installation and commissioning of grid connections, dispatch and settlement. Hydro One will provide incentives for completed installations and monitor the project to assess its effectiveness but Hydro One will not be a direct participant in the project.

Evaluation: GenSet completed four installations in 2007 connecting a total of 3.8 MW of standby generation capacity for which Hydro One provided $190,000 in total incentives. The program costs are born by the participants and the associated dispatched load is claimed and accounted for by IESO as a part of their demand response efforts.

Industrial: Industrial Energy Efficiency Assessments

This project was initiated as a pilot in 2005 to assess the effectiveness of employing a systemic approach to assisting commercial and industrial customers to identify energy efficiency opportunities. The project was completed in 2007 and the primary lesson learned from the exercise was that while the standard audit approach is appropriate for some customers, it is not necessarily a good fit for all cross sections of our industrial customers with different levels of awareness and engagement in conservation activities. This has been a worthwhile project and we have learned a great deal from it, however, we are not planning to continue with the approach in 2008.

Description:
The first phase of this pilot project used the energy diagnostic tool, *One-2-Five Energy Diagnostic,* to provide customers with an assessment and benchmarking report of their current energy management practices. Fifteen of Networks' large distribution connected industrial customers had this interactive workshop performed on their premises. This workshop provided the customer with information on their energy management practices in relation to the company's own operating costs and to other similar industries, as well as suggestions on key areas for improvement and an estimation of potential energy cost savings.

The second phase of the pilot includes further detailed on-site assessments to identify specific energy efficiency measures to develop a work plan.

Design:
A total of 15 industrial distribution customers participated in the project and each customer was visited by the energy auditors and received a diagnostic report, a benchmarking report, as well as an indication of the level of savings that can be achieved in their facility. We also secured agreement from four of the fifteen customers to proceed with a second phase site assessment which included a more in-depth energy review to identify on-site key energy savings opportunities and the development of an action plan. Once the detailed audits were completed, a repeat diagnostic session was conducted to summarize the improvements and to develop the next steps.

Intent:
The objective of this program is to enable large industrial customers (above 2MW) to realize savings from conservation and demand management projects in their facilities. Different customer types, including forestry, food and beverage, automobile and processing were targeted so that the findings can be used to target and develop future CDM programs.

Delivery:
The vendor completed the two phases of this pilot in 2007 by providing diagnostic sessions for 15 selected customers plus four additional phase all detailed on-site energy audits leading to actionable work plans.

Evaluation: For the 15 participants, the initial assessments identified generic potential savings in excess of $17M per year. For the 4 customers that engaged in the second phase and developed specific plans to take action, 18 million kWh in potential savings were identified. This project, however, was intended to be a pilot to assess the viability of the approach in the business markets and as such, the reported potential savings are not credited as results to this effort (the realized savings are captured in other CDM programs such as PowerSaver Business Incentive program described on page 37).

This project was initiated as a pilot to assess effectiveness of the *One-2-Five Energy Diagnostic.* The primary lesson learned from this exercise was that the standard audit approach is appropriate for some customers but by and large our customers are at different levels of engagement and awareness with regards to conservation efforts and thus one standard approach is not sufficient to address the needs of our customers. While we are not planning to continue with this approach, this has been a worthwhile project and we have learned a grate deal in the process.

Industrial: Interim Time of Use Pilot

Description:
The pilot offers customers rate incentives through the application of rates that help to shift electricity demand away from periods of maximum demand and into the off-peak periods. Depending on the difference in demand between the two time periods, customers could realize substantial savings in their distribution bills. Networks currently has three customers participating in the pilot.

Design:
Hydro One Distribution received approval from the Ontario Energy Board to implement distribution time of use rates for customers whose off-peak demand consumption (kW) was at least twice their on-peak demand consumption. The demand rate is set to zero for the off peak period defined as 7pm to 7am Monday to Friday, and all day on weekends and holidays.

Intent:
Determining if customers will modify their consumption patterns to take advantage of time of use rates will indicate whether Distribution charges are an impediment or a significant factor, as compared to the generation component, in promoting load shifting by customers. Encouraging commercial and industrial customers to shift their demand away from the peak will benefit both those customers and the electricity system as a whole.

Delivery:
Customers whose operation patterns qualify for the interim time of use rate will be eligible to participate in the pilot. Their demand in the off peak hours must be twice that in the on peak period.

Evaluation:
While there has been some interest in learning about the details of the time of use rate by several companies, no additional customers have yet been willing to modify their operation patterns in order to qualify for the interim time of use rate. Early indications are that the distribution component of electricity rates is a not significant enough factor in the customer's total cost structure to warrant such changes to operating procedures. Another reason that no new customers have elected this price option is the interim nature of the rate. Ski resort operators expressed interest if the rate would be made permanent.

Common: Distribution System Loss Reduction

Reduces distribution line losses, directly benefiting all Networks customers as well as reducing provincial demand during peak demand periods.

Description:
The Distribution System Loss Reduction Program involves identifying and implementing projects where incremental investments will result in an overall economic benefit to customers by reducing system delivery losses.

Design:
A research report was commissioned in 2005, updated in 2006 to better reflect the distribution system, to identify the areas where Networks could pursue projects that would economically reduce system delivery losses. Identified opportunities were in the areas of power factor correction (by installation of capacitor banks) and feeder phase balancing.

Intent:
Lowering distribution system delivery losses will reduce overall system demand and it will also provide additional network capacity for growth. System delivery losses are currently passed onto all customers; therefore, improvements in this area will benefit all customers.

Delivery:
Distribution line studies are undertaken to determine which lines require power factor correction, what size capacitor bank is appropriate, the proper location for the capacitor bank and to establish any phase balancing that may be required. Following the study period, capacitor banks are purchased and installed, with any line balancing taking place at the time of installation. All work is carried out with Networks staff.

Evaluation:
By December 31, 2007 over 70% of the projects had been completed. The remainder will be completed by April 2008, under the extension approved by the OEB.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Distribution Line Loss Reduction (219 projects completed)	5,399	7,207,655	2,362	144,153,108

Farms: Farm Energy Efficiency

A cooperative relationship has been established among the key organizations concerned with energy farm energy efficiency, which has led to the implementation of general product incentives applicable for farm activities as well as agriculture specific products and to the provision of related education material.

Description:
Networks has undertaken several initiatives to assist the farming community with electrical conservation and efficiency. These initiatives included conducting energy audits, producing informational material, as well as the signing of a Memorandum of Understanding (MOU) with the Ministry of Agriculture, Food and Rural Affairs, Ontario Power Authority, Ontario Ministry of Energy and the Ontario Federation of Agriculture, to co-operate with the development of agricultural energy efficiency initiatives.

Design:
As with other aspects of this CDM program, Networks' approach to farm energy efficiency has been to seek out beneficial partners wherever possible. This has led to many co-operative efforts with the Ministry of Agriculture, Food and Rural Affairs, Ontario Power Authority, Ontario Ministry of Energy and the Ontario Federation of Agriculture, as well as other parties. These efforts contributed to the design of the prescriptive portion of the PowerSaver Business Incentive Program (lighting and motors). The prescriptive portion has been expanded to include a number of agriculture specific products.

Intent:
The objective of the Farm Energy Efficiency Program is twofold: to offer the farming community the information and the tools necessary to realize savings in the energy consumption of their farms, and provide customers with incentives for moving to energy efficient agricultural technologies.

Delivery:
Co-operative efforts commenced with a series of energy efficiency audits of dairy, poultry and swine operations. These efforts involved the development of audit software, tools and training materials, as well as the execution of the audits.

Assessment of the audits and the state of the industry led to the development of informational material to increase farmers' knowledge and awareness of efficiency improvements that could be applied to their operations. Fact sheets, educational television segments, as well as informational DVDs were produced.

Advertising for the PowerSaver Business Incentive Program geared towards agriculture customers is being conducted by Hydro One and its MOU partners at relevant conferences and through agricultural publications.

In 2007, HONI provided funding to Ag Energy Co-Operative Ltd. for its 'Lessons Learned' Total Energy Program designed to help agricultural and greenhouse operations in Ontario reduce their energy consumption of both heat and electricity by over 20%. Greenhouse and non-greenhouse operations were audited and energy efficient measures installed and

monitored. An energy management investment business plan was presented to producers for the greenhouse and non-greenhouse sectors at the Growing the Margins Energy Conference held on April 12-13, 2007 in London, Ontario.

Evaluation:

The farm videos and Fact Sheets continue to be well received at conferences and are available via the internet.

In 2007 the PowerSaver Business Incentive Program (PBIP) had a significant uptake in the Farm sector, with 34 projects completed and $42,000 released as incentives. The majority of the measures implemented in these retrofit projects were heat pads for the swine industry and lighting technologies.

HONI continues to work with the Ontario Power Authority to expand the list of prescriptive measures for farms under their Electricity Retrofit Incentive Program, which has replaced HONI's PBIP.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Annual Savings kW	Cumulative Lifecycle kWh
Farm Energy Efficiency (includes 34 PBIP Farm projects completed)	267	1,970,695	349	17,454,329

Other: Smart Meters

Paperless change meter processes for the large scale deployment of smart meters have been successfully developed and field tested.

Description:
The provincial government has set targets for installing smart meters in the homes of all Ontario residents by 2010, with the first provincial target of 800,000 smart meters by 2007. Networks is taking a leadership role in the implementation of smart meters.

Design:
The MARR funding for Smart Meters was intended to cover the development of business process activities related to meter installations. With the passage of Energy Act, Bill 21, Networks was able to restart the project with a pilot program in East Gwillimbury to test meter installation processes using some of the 25,000 meters purchased in 2005. By December 2007, Networks had installed 250,000 residential meters.

Intent:
The government's stated intent is that smart metering provide the ability to record consumption in time intervals that can be matched to price signals which differ throughout the day to reflect the true cost of power. Understanding and reacting to proper pricing is an essential component to creating a conservation culture and managing customer demand. The largest benefit of smart meters is providing customers with the ability to understand their consumption patterns so they can make effective decisions on usage.

Delivery:
Although Networks has installed about 250,000 residential meters, only **19,500** were funded through CDM. More importantly, Networks implemented a paperless change meter process where service information (e.g. change meter request, GPS, barcode, store old meter reading in the new meter, etc.) can be exchanged between head office groups and field staff automatically resulting in a faster and more efficient process for mass meter deployment. Previously, the change meter process was done manually via paper records.

Evaluation:
The government has not provided estimates for kWh savings and has not required the reporting of benefits for smart metering. The Smart Meter program approved by the OEB in 2005 as part of the overall CDM initiative was $1.4 M in OM&A and $6.4 M in capital for a total of $7.8 M. About $0.5 M of the approved amount was spent in 2005. In 2006 the expenditure of another $7.3 M represented the remaining portion of the OEB's approval. No additional CDM funds were spent in 2007. Thus 19,500 meters were installed through the CDM funding. Also included in the costs are expenditures for developing and implementing the overall smart meter strategy; readying the AMR and billing systems and customer communication.

Program	LTD Spending to Dec 2007 ($K)	Cumulative Annual Savings kWh	Cumulative Lifecycle kWh
Smart Meters (19,500 meters installed)	7,800	n/a	n/a

Other: Program Management and Research

A portion of Networks' project management and research budget has been spent on commissioning reports and sponsoring studies related to conservation and demand management. The results of these studies are being used to assist in program development and for further understanding the scope of conservation and demand management.

Some of the studies that Networks has commissioned, participated in, or funded to date include:

- Avoided Cost of Generations Study
    - Prepared by Navigant

- Distribution Loss Reduction Strategy
    - 2 reports prepared by Kinetrics

- Residential Appliance Survey
    - Networks surveyed residential, seasonal and farm customers to determine equipment penetration rates and demographics in order to facilitate the roll-out of conservation and demand management initiatives that will benefit our customer base

- Hydro One Overview of Residential Customer
    - Prepared by Antim Consulting, filed as an interrogatory response in the CDM generic hearing

- Demand Management Potential
    - Prepared by Kinetrics, filed as an interrogatory response in the CDM generic hearing

Networks is a member of the Customer Energy Solutions Interest Group (CESIG) of CEA Technologies Inc. – members include many of the provincial utilities across Canada, Natural Resources Canada and the National Rural Electric Cooperative Association out of the United States. Networks has participated in funding several CESIG initiatives, including the testing of Energy Star CFLs and the preparation of a series of reference guides similar to the Product Knowledge Guide series originally published by Ontario Hydro. Guides completed or under development include Lighting, Motors, Compressors, Heat Pumps, Power Quality, Electrotechnologies, Fans and Blowers, et cetera. Several guides are available on Networks' website and others will be made available as they are released.

Incremental staff costs associated with managing the CDM portfolio are charged to Program Management. Consultant and contract labour associated solely with a specific initiative are charged directly to that initiative.

Lessons Learned

Networks' efforts in Conservation and Demand Management have identified a number of lessons learned or key findings, which will be useful for Networks and others as CDM continues to evolve in Ontario.

Some of these findings are on a macro level, based on broader policy, structures and inter-relationships, while others are more program specific.

Customer Feedback

- A significant fraction of customers (business and residential) are motivated to reduce their consumption of electricity and to reduce their peak demand. With access to information (in home displays, workshops, technology guides, etc.) and reasonable incentives, customers make not only technology changes, but also behavioural changes in order to reduce their electricity footprint. This was clearly demonstrated in programs such as Double Return and with in home displays.
- Prescriptive measures, where feasible, are easier for customers to understand and undertake and are easier for the utility to administer. Prescriptive measures need to be expanded and targeted to individual business sub-sectors (farm, industrial, commercial) to maximize each sector's participation.
- Program timing must be aligned with customer budget cycles, in particular for the Commercial, Industrial and MUSH sectors
- Customers, especially residential customers, respond well to non-monetary incentives and seem to be motivated by environmental concerns.
- CDM programs can be a powerful mechanism in changing customer behaviour and for encouraging development of innovative market transformation technologies, such as in-home displays.
- To run successful programs in small close knit communities, it is necessary to engage the community. Public events run in conjunction with local organizations provides an opportunity to become known to the community, to answer questions, promote the program and identify "early adopters" which are key to broad based participation.
- The use of skilled local contractors and trades people provides an additional level of comfort to participants and further enhancing the skill level of local people helps to retain expertise in the community, thereby extending the application of current energy efficiency techniques into the future and into additional houses.
- Bill Inserts are the most effective and cost-efficient method to reach residential and small business customers. They are also very useful for targeted programs where advertising spill would be an issue. For business customers direct mail and workshops have also proved effective.
- Initiatives which involve more complex decisions or newer technology may require an educational component and have a longer purchasing decision process.
- Programs which seek to gain greater penetration rates require increasing marketing efforts in order to gain incremental participants.

Program Management

- A turn key implementation approach for multifaceted or complex programs creates a clear understanding of where responsibility lies for all deliverables and results in a speedy resolution of any issues. This has been particularly useful in programs such as load control where promotion, enrolment, installation, and customer care are interdependent activities.
- For new and emerging technologies, or for new or high risk applications in the marketplace, pilots (such as for Load Control or In-Home Displays) and/or staged rollouts are very valuable in:
    - establishing the effectiveness of the device in either reducing energy consumption or shifting peak demand
    - refining logistics, incentive levels, and product selection,
    - assessing delivery channels, marketing and delivery costs,
    - determining customer acceptance and overcoming barriers to customer participation.
- Leverage existing channels such as the Social Housing Services Corporation
- Partnering with other organizations can bring existing skills and knowledge to bear and helps avoid duplicate or counter productive activities.
- The Hydro One service territory, due to its large size but low population density, is a difficult and less attractive one for retailers, suppliers and other partners to serve.
- Application based programs have a considerable "ramp up" time required to engage customers, educate them, and to receive & process applications, all of which is required before installations can take place. Interruptions in the continuity of the program offering can significantly curtail participation. Projects may take from 6-12 months or longer to design and implement, especially in the business market. In many cases the customer business cycle does not coincide with the LDC CDM cycle.
- Program incentives levels need to be at sufficient levels in order to catch the customer's attention. Failure to set incentives at appropriate levels may result in capturing only early adopters and free riders, resulting in an inability to sustain growth in customer participation. Multi-tiered incentive structures are required to encourage the implementation of more expensive and/or more difficult measures.

Evaluation

- The assessment of conservation program success should be based on customer engagement and satisfaction as well as on numerical results.
- The Assumptions and Measures spreadsheet, which is used as the basis for TRC tests, should have its assumptions updated to reflect more current data and the breadth of measures expanded to cover additional products and services, especially those being promoted by LDCs.
- The assumption basis for TRC should provide value for winter peak, not only summer peak. Many local distribution systems, including parts of Hydro One Networks, are winter peaking.
- The assumptions for avoided costs in the OEB TRC Guide and those in the approved IPSP should be consistent.

- Savings on distribution charges only are not sufficient to encourage commercial and industrial customers to modify operations to off peak time of use rates. The generation commodity costs are much more significant savings opportunity for customers than are foregone distribution costs.

Conclusions

As we ended 2007 substantial results have been accomplished. Programs had been launched and completed, with significant results achieved.

- The CDM program portfolio to date has produced over $3.40 of societal benefits for every $1 spent on program costs, as measured through the Total Resource Cost (TRC) test. In addition net TRC benefits of $88 million have been produced.
- Participation in Networks' CDM programs reached almost 1.2 million life-to-date.
- Customers' response to the Residential Load Control Program (SmartStat) continued to show a strong performance throughout 2007. Enrolment reached the target of 10,000 participants on schedule in June, 2007.
    - Hydro One initiated two successful load control events in July and August during the hottest days of the summer, reducing peak demand by up to 13 MW.
- Double Return program was launched in the winter of 2007 as a new demand response initiative targeted at Commercial/Industrial distribution-connected customers.
    - This program exceeded expectations by achieving 38MW in winter peak reduction and 33MW in the summer.
- The Mass Market programs produced very positive results.
    - The Cold Shoulder Appliance Pickup program gained considerable participation levels (over 11,000 appliances) which led to its expansion to all of southern Ontario in early 2007.
    - Over 242,000 energy efficient products were purchased through the Spring campaign of the Every Kilowatt Counts program.
- The Residential In-Home Display program reached distribution of 31,000 units in northern Ontario. Additionally, the Association of Energy Services Professionals (AESP) awarded their Energy Efficient Technology Deployment of the Year award in 2006 to Hydro One and Blue Line Innovations (the manufacturer of the product) for the successful deployment of the Power Cost Monitor. A pilot to test the efficacy in a time-of-use rate environment showed that there is substantial incremental peak and consumption savings value to in home displays under a time-of-use or any rate regime.
- The newly launched online audit generated participation by 6,000 residential and small business customers, and 4,000 completed audits, during the last quarter of 2007.
- The PowerSaver Business Incentive program provided incentives to 110 business and farm customers.
- The Low Income and Social Housing programs were completed and were models for other organizations to follow. These customer groups are among the least able to undertake retrofits on their own and require significant financial assistance.
- Smart Pack educational initiative was delivered to 6,000 grade 5 students in 2007.
- Almost three-quarters of the distribution line loss reduction projects were completed.

Programs that will continue up to April 2008 include:

- The remaining Line Loss Reduction projects will be completed
- The TOU Interim Pilot will be completed

Long-term secured funding must be in place for LDCs in order to provide a stable basis for CDM program planning and customer decision making. The 3rd tranche MARR funding from 2005-2007 was a successful model which provided this stability an allowed momentum to build for the LDC and the customer.

Appendices

Appendix A - Evaluation of the CDM Plan

	Cumulative Totals Life-to-date [5]	Total for 2007	Residential	Commercial / MUSH	Industrial	Agricultural	LDC System	Smart Meters [4]	Other
Net TRC value ($):	$ 88,341,183	$ 42,818,333	$ 21,352,015	$ 9,864,878	$ 6,963,387	$ 572,175	$ 4,843,221		$ (777,343)
Benefit to cost ratio:	3.40	3.07	3.01	3.89	10.49	2.00	2.07		0.00
Number of participants or units delivered:	1,169,365	289,132	280,482	7,628	753	50	219		
Lifecycle (kWh) Savings:	1,447,908,244	811,957,203	333,218,785	208,640,922	108,898,068	17,046,320	144,153,108		0
Report Year Total kWh saved (kWh):	271,877,550	172,759,303	40,472,963	14,317,770	108,854,220	1,906,695	7,207,655		0
Total peak demand saved (kW):	63,771	53,143	14,678	1,989	33,773	340	2,362		0
Total kWh saved as a percentage of total kWh delivered (%):	0.36%	0.67%	0.35%	0.22%	3.85%	0.083%	0.00%		
Peak kW saved as a percentage of LDC peak kW load (%):	1.39%	1.16%	0.67%	0.18%	8.37%	0.08%	N/A		
Report Year Gross C&DM expenditures [1] ($):	$ 38,193,700	$ 17,756,290	$ 8,704,035	$ 663,416	$ 2,746,855	$ 343,393	$ 4,521,248		$ 777,343
Expenditures per Lifecycle KWh saved [2] ($/kWh):	$ 0.02	$ 0.02	$ 0.02	$ 0.00	$ 0.02	$ 0.01	$ 0.03		
Expenditures per KW saved [3] ($/kW):	$ 214	$ 114.31	$ 219	$ -	$ 80.02	$ -	$ -		

Utility discount rate (%):	5.73

1 Expenditures are reported on accrual basis.
2 Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate energy savings
3 Expenditures include all utility program costs (direct and indirect) for all programs which primarily generate capacity savings.
4 Please report spending related to 3rd tranche of MARR funding only. TRC calculations are not required for Smart Meters. Only actual expenditures for the year need to be reported.
5 Includes total for the reporting year, plus prior year, if any (for example, 2007 CDM Annual report for third tranche will include 2006, 2005 and 2004 numbers, if any.

Appendix B - Discussion of the Program

A. **Name of the Program:** Residential In-Home Display Program

Description of the program (including intent, design, delivery, partnerships and evaluation):

During 2006 and 2007, Networks made over 30,000 Power Cost Monitors™ available to residential customers in Northern Ontario. Customers use the Monitors to check and manage their electrical consumption in real-time. They are able to view their current usage rate and cumulative consumption in kWh, as well as an estimate of the cost of that consumption. Networks' initiative is the largest of its kind in North America.

Measure(s):

	Monitors		
Base case technology:	Ave. 11,500 kWh/yr.		
Efficient technology:	750 kWh savings - ave. 6.5%		
Number of participants or units delivered for reporting year:	10,652		
Measure life (years):	5		
Number of Participants or units delivered life to date	30,952		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 2,947,762	$ 8,479,985
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 90,337	$ 101,439
Incremental Measure Costs (Equipment Costs)	$ 1,887,535	$ 5,422,323
Total TRC costs:	$ 1,977,872	$ 5,523,762
Net TRC (in year CDN $):	$ 969,890	$ 2,956,223
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	1.5	1.5

C. **Results:** (one or more category may apply)

			Cumulative Results:	
Conservation Programs:				
Demand savings (kW):	*Summer*	1,410	4,767	
	Winter	4,202	14,207	
	lifecycle	in year	Cumulative Lifecycle	Cumulative Annual Savings
Energy saved (kWh):	40,684,931	8,136,986	114,732,007	22,946,131
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):			
Energy generated (kWh):			
Peak energy generated (kWh):			
Fuel type:			

Other Programs (specify):

Metric (specify):			

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 90,337	$ 101,439
	Incentive:	$ 1,749,260	$ 4,980,637
	Total:	$ 1,839,597	$ 5,082,076
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Savings per participant of 749.9 kWh were based on the evaluation of the 2005 pilot program that found average savings were 6.5% of average consumption (ave.consumption is 11,500 kWh/yr. for Northern Ontario). Peak savings of 0.13kW were based on the TOU Pilot results conducted during summer 2007.
Customer equipment costs include cost of monitor, tax, shipping and the cost of replacing batteries.
Incentive costs include cost of monitor and tax.
$2,500 were excluded from the TRC and added in the RTM First Nation program

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Residential Real Time Monitoring Pilot (2004-2005)

Description of the program (including intent, design, delivery, partnerships and evaluation):

Objectives of this pilot were to assess residential customer behaviour and quantify potential energy savings arising from the provision of real-time energy usage and cost data. The real-time monitor is an in-home display device that receives a wireless signal from a sensor placed on the exterior electro-mechanical electricity meter. The study operated from July 2004 to August 2005, thus capturing both winter and summer peak periods. Customers were able to track their energy consumption (in kWh) and cost, and also receive instant feedback on actions taken.

Measure(s):

	Measure		
Base case technology:	Ave. 16,176 kWh/yr.		
Efficient technology:	1051 kWh savings - ave. 6.5%		
Number of participants or units delivered for reporting year:	382		
Measure life (years):	5		
Number of Participants or units delivered life to date	382		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	$ 127,038
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ -	$ 463,411
Incremental Measure Costs (Equipment Costs)	$ -	$ 5,730
Total TRC costs:	$ -	$ 469,141
Net TRC (in year CDN $):	$ -	-$ 342,103
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	0.0	0.3

C. **Results:** (one or more category may apply)

Conservation Programs:

			Cumulative Results:	
Demand savings (kW):	*Summer*	-		38
	Winter	-		114.4
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	-	-	2,007,410	401,402
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		

Peak hours dispatched in year (hours):			

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ -	$ 463,411
	Incentive:	-$ 50	$ 3,010
	Total:	-$ 50	$ 466,471
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Evaluation report prepared by external consultant (Dean Mountain) found 6.5% average savings.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Residential Load Control (Smartstat)

Description of the program (including intent, design, delivery, partnerships and evaluation):

Smartstat residential load control program was launched in July, 2006. This program is designed to achieve summer peak demand reduction by controlling air-conditioning (AC) temperature set-points using web-enabled programmable thermostats, and by cycling electric water heater loads using an off/on switch. The initial target of 6,000 enrolments was achieved well ahead of schedule in December 2006 and as a result a new goal of 10,000 participants was adopted to be achieved prior to the upcoming summer. All 10,000 installations were completed by June 2007

Measure(s):

	Prog Thermostats	Tank Wrap/Pipe wrap	15 w CFLs	Load Control
Base case technology:	18,103 kWh/yr	5,000 kWh/yr	139 kWh/yr	
Efficient technology:	16,637 kWh/yr	4,730 kWh/yr / 4,924 kWh/yr	35 kWh/yr	
Number of participants or units delivered for reporting year:	8313	755	12,626	8,313
Measure life (years):	18	6	4	18
Number of Participants or units delivered life to date	10,000	1092	16,000	10,000

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($)*	$ 10,518,328	$ 13,301,164
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 832,948	$ 1,453,382
Incremental Measure Costs (Equipment Costs)	$ 875,654	$ 1,054,943
Total TRC costs:	$ 1,708,602	$ 2,508,325
Net TRC (in year CDN $):	$ 8,809,726	$ 10,792,839
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	6.2	5.3

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW): *Summer*	11,029		11,174
Winter	21830		22117

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	40,031,219	3,306,662	48,811,867	4,113,097
Other resources saved :				
Natural Gas (m3):	9,011,708	500,650	10,840,796	602,266
Oil (litres):	3,311,404	183,967	3,982,606	221,256
Propane (litres):	1,000,677	55,593	1,202,907	66,828

Demand Management Programs:

Controlled load (kW)	9,974	11,998
Energy shifted On-peak to Mid-peak (kWh):	2,122,299	2,552,988
Energy shifted On-peak to Off-peak (kWh):	1,071,943	1,289,478
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		

Peak hours dispatched in year (hours):			

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*	$ 488,863	$ 632,718
	Incremental O&M:	$ 344,085	$ 587,316
	Incentive (capital and O&M):	$ 1,586,063	$ 3,316,210
	Total:	$ 2,419,011	$ 4,536,244
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Assumed that half of the customers already have a programmable thermostat (50% free-ridership) pending analysis.
Load control events are assumed to shift load, but not to save energy. Energy savings come from the provision of two CFLs to all participants, as well as the tank wrap and pipe insulation of homes with electric water heaters.
A $40 value was assumed for the capability to control the thermostat via the internet. The assumed the value of a basic programmable thermostat without the load control features was $60, and installation value was assumed to be $50.
The "residual" cost of the programmable thermostats of $200 represents the utility's direct cost for the load control capability. $101 included in direct costs was the unit cost of the water heater switches. Direct costs also included the costs of marketing, enrollment, project management, and Canon's load management system.

Direct program costs include switches for hot water heaters installed (but exclude switches in inventory). Direct costs also include the difference in value between the $40 web access feature plus the $110 installed cost of "basic" programmable thermostat, and the full cost of the installed thermostats ($350) that included the load control features.Demand reduction of 0.5 kW for water heaters and 1.1 kW for cooling were based on the results from the pilot program.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a custome are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Residential Load Control Pilot (2005)

Description of the program (including intent, design, delivery, partnerships and evaluation):

The objectives of this pilot were to assess residential customer response and potential load impact of controlling central air conditioning, pool pumps, and electric water heating during system peak periods, through installations of load control units and interval meters. Controls were placed on 581 devices in 416 randomly selected homes in three HONI service areas (Kingston, Simcoe, Newmarket). The project ran from July 2004 to December 2005. Participants were paid a monthly incentive for their participation.

Measure(s):

Base case technology:				
Efficient technology:				
Number of participants or units delivered for reporting year:	0			
Measure life (years):				
Number of Participants or units delivered life to date	416			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	$ -
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ -	$ 739,976
Incremental Measure Costs (Equipment Costs)	$ -	$ -
Total TRC costs:	$ -	$ 739,976
Net TRC (in year CDN $):		-$ 739,976
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		0

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*				
	Winter				
		lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):		0	0	0	0
Other resources saved :					
Natural Gas (m3):					
Other (specify):					

Demand Management Programs:

Controlled load (kW)		358
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:		$ 669,520
	Incentive:		$ 41,038
	Total:		$ 710,558
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

The 358 kW in demand savings did not produce any TRC benefits due to the avoided costs for Demand being zero in 2005.

The credit to costs in 2006 reflected a correction to Hydro One Brampton's cost-sharing.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a custome are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Cold Shoulder Appliance Pickup program

Description of the program (including intent, design, delivery, partnerships and evaluation):

The Cold Shoulder Appliance Pickup program provides customers with free in-home pickup of secondary, operating refrigerators, freezers and room air conditioners.

Measure(s):

	Refrigerators	Freezers	Room Air Conditioners
Base case technology:	1,200 kWh	900 kWh	900 kWh
Efficient technology:	0	0	0
Number of participants or units delivered for reporting year:	4,589	2,247	418
Measure life (years):	6	6	4
Number of Participants or units delivered life to date	7,141	3,489	695

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	5,495,122	$ 8,580,027
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 925,908	$ 1,340,793
Incremental Measure Costs (Equipment Costs)	$ 706,721	$ 1,101,140
Total TRC costs:	$ 1,632,629	$ 2,441,933
Net TRC (in year CDN $):	$ 2,275,601	$ 2,275,601
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	3.4	3.5

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	1,961	3,095
	Winter	1,626	3,390

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	85,557,632	10,376,962	133,466,659	16,194,283
Other resources saved :				
Natural Gas (m3):				
Oil (litres) :				
Propane (litres):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 925,908	$ 1,340,793
	Incentive:	$ 53,804	$ 84,947
	Total:	$ 979,712	$ 1,425,740
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Participants received an energy efficiency pack at time of pickup which included 2 CFLs and a timer, along with information on how customers could save energy in their home.

Assumptions for Room Air Conditioners -
1. For Base case technology 900 kWh/yr. is used (this is a conservative estimate since average model being sold today is 880 kWh/yr. as per OEB spreadsheet, and current models will be more efficient than the older models being picked up under this program). Average peak demand used is 1.129 kW (as per Keep Cool results).
2. For Measure Life 4 years is used. This is based on calculating the remaining life of a recycled unit is the same proportion of technology life as was used for Refrigerators in OEB spreadsheet (6 yrs. remaining life / 19 yrs. total life = approx. 1/3). Thus 1/3 of the technology life of 12 years for a room air conditioner is therefore 4 years.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a custome are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Every Kilowatt Counts

Description of the program (including intent, design, delivery, partnerships and evaluation):

The Every Kilowatt Counts program was a residential education and coupon incentive campaign of the Ontario Power Authority. The Spring 2007 campaign ran from April 15 to June 17, 2007. Products included in Spring campaign were CFLs, ceiling fans, dimmer switches, outdoor motion sensors, outdoor solar lights and furnace filters.

Measure(s):

	Spring campaign	Fall campaign	Total
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	241,823		241,823
Measure life (years):			
Number of Participants or units delivered life to date	531,639	437,175	968,814

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 3,793,513	$ 43,682,703
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 1,195,100	$ 3,328,762
Incremental Measure Costs (Equipment Costs)	$ 396,767	$ 2,993,468
Total TRC costs:	$ 1,591,867	$ 6,322,230
Net TRC (in year CDN $):	$ 2,201,646	$ 37,360,473
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	2.4	6.9

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	50	1,214
	Winter	3,336	20,855

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	61,859,334	11,373,451	443,927,260	75,044,621
Other resources saved :				
Natural Gas (m3):				1,244,800
Oil (litres)				803,787
Propane (litres)				253,413

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):			
Distribution system power factor at beginning of year (%):			
Distribution system power factor at end of year (%):			

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):			
Energy generated (kWh):			
Peak energy generated (kWh):			
Fuel type:			

Other Programs (specify):

Metric (specify):			

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 95,100	$ 211,679
	Incentive:		$ -
	Total:	$ 95,100	$ 211,679
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

OPA has not provided any data on 2007 EKC results except for number of coupons per product, for the province as a whole. Thus we have assumed the same proportion of provincial results for Hydro One Networks as last year, based on customer counts (20.5%).
We have also assumed that OPA program costs are similar to last year, and then taken 20.5% of that number, or $1.1 million, as program delivery costs from OPA.
Load impacts for solar garden lights and furnace filters are currently unavailable and thus those two products have no energy or demand results.

1 We also have no impact per unit for outdoor solar lights or furnace filters and so no results are being counted from these products.

2 For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Low Income - CMHC/NRCan Program

Description of the program (including intent, design, delivery, partnerships and evaluation):

Hydro One's Low Income program (Home Energy Efficiency grant) provides financial incentives for energy efficiency upgrades to low income Hydro One customers who heat their homes with electricity. The program offers up to $3,000 per qualifying household. The program launched in September 2005; 24 audits and retrofits were completed by the end of 2007. Home improvements include basement, wall and attic insulation, doors and window upgrades, weatherstripping and caulking.

Measure(s):

Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	10		
Measure life (years):			
Number of Participants or units delivered life to date	24		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 70,426	$ 210,103
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ -	$ 8,758
Incremental Measure Costs (Equipment Costs)	$ 23,356	$ 61,930
Total TRC costs:	$ 23,356	$ 70,688
Net TRC (in year CDN $):	$ 47,070	$ 139,415
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	3.0	3.0

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0	0
	Winter		27

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	1,484,800	59,392	4,429,625	177,185
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	**Cumulative Life to Date**
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ -	$ 8,758
	Incentive:	$ 23,356	$ 61,930
	Total:	$ 23,356	$ 70,688
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions and Comments :

Results are based on pre- and post-audits conducted on each home.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** First Nations Retrofit

Description of the program (including intent, design, delivery, partnerships and evaluation):

Under the EnerGuide for Houses Program, The Abor Group had been retained by NRCan to perform audits on First Nations housing. An assessment of these audits identified 55 electrically heated homes in 6 communities that required cost effective thermal envelope retrofits. In all, 125 houses received some conservation measures.

Measure(s):

	Homes		
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	125		
Measure life (years):			
Number of Participants or units delivered life to date	125		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 662,448	$ 662,448
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 19,385	$ 19,385
Incremental Measure Costs (Equipment Costs)	$ 109,447	$ 109,447
Total TRC costs:	$ 128,832	$ 128,832
Net TRC (in year CDN $):	$ 533,616	$ 533,616
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	5.1	5.1

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	2	2	
	Winter	676	676	
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	13,596,532	708,063	13,596,532	708,063
Other resources saved :				
Other (propane):				
Other (water):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 19,385	$ 19,385
	Incentive:	$ 108,781	$ 108,781
	Total:	$ 128,165	$ 128,165
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Assumptions:
1) CFLs 15W - OPA Low income report
2) Airsealing: Abor Group assumptions based on CMHC's Renovating for Energy Savings, October 2004 and OEB TRC Guide; load shape from OEB Measures and Assumptions list
3) Full Airsealing: The Abor Group assumptions based on CMHC's Renovating for Energy Savings, October 2004 and 2006 OEB TRC guide
4) Attic and Basement Insulation: The Abor Group Based data from CMHC's Renovating for Energy Savings, October 2004 and load shape from OEB Measures and Assumptions list

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Low Income - Retrofit - Green Communities Canada

Description of the program (including intent, design, delivery, partnerships and evaluation):

With Hydro One covering the cost of extended measures (i.e. weatherstripping and insulations) for its customers with electric heat (plus some basic measures and audits not covered by the OPA), the OPA was able to direct more of their pilot budget towards infrastructure development. The Vendors coordinated all work on behalf on Hydro One and the OPA and billed the appropriate party for relevant work. A total of 54 homes had measures installed through this project.

Measure(s):

	Homes Retrofitted		
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	54		
Measure life (years):			
Number of Participants or units delivered life to date	54		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 135,564	$ 135,564
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 10,598	$ 10,598
Incremental Measure Costs (Equipment Costs)	$ 72,915	$ 72,915
Total TRC costs:	$ 83,513	$ 83,513
Net TRC (in year CDN $):	$ 52,051	$ 52,051
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	1.6	1.6

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	6		6
	Winter	70		70
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	2,731,179	114,522	2,731,179	114,522
Other resources saved :				
Other (propane):				
Other (water):				

Demand Management Programs:

Controlled load (kW)	
Energy shifted On-peak to Mid-peak (kWh):	
Energy shifted On-peak to Off-peak (kWh):	
Energy shifted Mid-peak to Off-peak (kWh):	

Demand Response Programs:

Dispatchable load (kW):			
Peak hours dispatched in year (hours):			
Power Factor Correction Programs:			
Amount of KVar installed (KVar):			
Distribution system power factor at beginning of year (%):			
Distribution system power factor at end of year (%):			
Line Loss Reduction Programs:			
Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			
Distributed Generation and Load Displacement Programs:			
Amount of DG installed (kW):			
Energy generated (kWh):			
Peak energy generated (kWh):			
Fuel type:			
Other Programs (specify):			
Metric (specify):			

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 10,598	$ 10,598
	Incentive:	$ 70,561	$ 70,561
	Total:	$ 81,159	$ 81,159
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

For Fridge savings (15' and 18'), the OPA Low income Report was used.
For Attic, Basement and Draft insulation, data based on advanced models provided by the vendor were used

TRC results are reported in Appendix C together with the Low Income - Retrofit project implemented by Envirocentre under the heading "Low Income-Retrofits"

1 Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed i the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

2 For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LD to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Low Income - Retrofit - Envirocentre

Description of the program (including intent, design, delivery, partnerships and evaluation):

With Hydro One covering the cost of extended measures (i.e. weatherstripping and insulations) for its customers with electric heat (plus some basic measures and audits not covered by the OPA), the OPA was able to direct more of their pilot budget towards infrastructure development. The Vendor coordinated all work on behalf on Hydro One and the OPA and billed the appropriate party for relevant work. In this project a total of 221 homes had measures installed.

Measure(s):

	Homes retrofitted		
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	205		
Measure life (years):			
Number of Participants or units delivered life to date	205		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 471,670	$ 471,670
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 34,493	$ 34,493
Incremental Measure Costs (Equipment Costs)	$ 219,941	$ 219,941
Total TRC costs:	$ 254,434	$ 254,434
Net TRC (in year CDN $):	$ 217,236	$ 217,236
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	1.9	1.9

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW): Summer	91		91
Winter	228		228

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	8,619,736	594,917	8,619,736	594,917
Other resources saved :				
Other (propane):				
Other (water):	7,820	652	7,820	652

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):			
Distribution system power factor at beginning of year (%):			
Distribution system power factor at end of year (%):			

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):			
Energy generated (kWh):			
Peak energy generated (kWh):			
Fuel type:			

Other Programs (specify):

Metric (specify):			

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 34,493	$ 34,493
	Incentive:	$ 247,978	$ 247,978
	Total:	$ 282,472	$ 282,472
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

For basic measures (e.g. CFLs, Detergent, pipe wrap, thermostats), OPA Low income assumptions were utilized when available. For basic measures not identified in the OPA Low Income report, the October 2006 -OEB Measures and Assumption list - or supporting research done by the vendor Envirocentre was used.
For insulation the OEB October 2006 Measures and assumptions list was used.

TRC results are reported in Appendix C together with the Low Income - Retrofit project implemented by Green Communities Canada under the heading "Low Income-Retrofits"

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Low Income - First Nations Pilot

Description of the program (including intent, design, delivery, partnerships and evaluation):

The First Nations Energy Conservation Project provided an integrated approach to energy conservation at the Chippewas of Georgina Island First Nation reserve, encompassing conservation education and housing retrofits. The Chippewas of Georgina Island First Nation was selected for the pilot program due to the community's location and its demonstrated knowledge and receptiveness to issues of conservation and renewable energy. In this community, Hydro One identified a total of 91 homes eligible for this program. Hydro One assigned the delivery of the program (audit, effectiveness studies and retrofit) to Windfall Ecology Centre.

Measure(s):

Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	0		
Measure life (years):			
Number of Participants or units delivered life to date	70		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ -	$ 152,356
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ -	$ 7,704
Incremental Measure Costs (Equipment Costs)	$ -	$ 56,124
Total TRC costs:	$ -	$ 63,828
Net TRC (in year CDN $):	$ -	$ 88,528
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		1.7

C. **Results:** (one or more category may apply)

Conservation Programs:

			Cumulative Results:	
Demand savings (kW):	*Summer*	0		3
	Winter	1		1
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	-	-	2,209,686	163,783
Other resources saved :				
Other (propane):				96
Other (water):		-		2,100

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):			
Peak hours dispatched in year (hours):			

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:		$ 7,704
	Incentive:	$ 6,521	$ 56,711
	Total:	$ 6,521	$ 64,415
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Costs incurred in 2007 refer to adjustments for

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed i the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** RTM First Nations

Description of the program (including intent, design, delivery, partnerships and evaluation):

During Fall 2007, Networks initiated the First Nations In-Home Display Program by providing real-time monitors to customers living in Northern Ontario First Nation communities at no cost.

Measure(s):

Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date	0		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 203,606	$ 203,606
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 11,809	$ 11,809
Incremental Measure Costs (Equipment Costs)	$ 70,348	$ 70,348
Total TRC costs:	$ 82,157	$ 82,157
Net TRC (in year CDN $):	$ 121,449	$ 121,449
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	2.5	2.5

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	52		52
	Winter	155		155
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	1,488,601	297,761	1,488,601	297,761
Other resources saved :				
Other (propane):				
Other (water):				-

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 11,809	$ 11,809
	Incentive:	$ 59,326	$ 59,326
	Total:	$ 71,135	$ 71,135
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Savings per participant of 749.9 kWh were based on the evaluation of the 2005 pilot program that found average savings were 6.5% of average consumption (ave.consumption is 11,500 kWh/yr. for Northern Ontario). Peak savings of 0.13kW were based on the TOU Pilot results conducted during summer 2007.
Customer equipment costs include cost of monitor, tax, shipping and the cost of replacing batteries.
$2,500 was moved from the RTM campaign to the First Nation campaign as these expenses were truly due to the RTM campaign

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Social Housing Program

Description of the program (including intent, design, delivery, partnerships and evaluation):

This program built on the success of the Social Housing Pilot Program launched in 2005. Hydro One, with over 5,000 homes in over 100 buildings, has become one of the the largest partner in Ontario SHSC programs. The funding included $50 per unit towards audits, up to $450 per unit for the implementation of measures designed to achieve electrical energy savings, as well as $50 per unit for energy awareness training.

Measure(s):

	Measures (Lighting, fridges, etc)		Audits
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	21956		1065
Measure life (years):			
Number of Participants or units delivered life to date	21995		2777

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 4,858,691	$ 4,865,991
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 472,604	$ 514,724
Incremental Measure Costs (Equipment Costs)	$ 1,938,043	$ 1,941,940
Total TRC costs:	$ 2,410,647	$ 2,456,664
Net TRC (in year CDN $):	$ 2,448,044	$ 2,486,761
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	2.0	2.0

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	722		725
	Winter	2086		2090
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	82,566,568	6,304,348	82,675,807	6,316,850
Other resources saved :				
Natural Gas (m3):	67764	16005	67764	16005
Other (water):	5940	495	5940	495

Demand Management Programs:

Controlled load (kW)

Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 138,830	$ 514,725
	Incentive:	$ 1,938,049	$ 1,955,057
	Total:	$ 2,076,879	$ 2,469,782
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

For measures included in the February 2006 OPA low income/social housing sector report (i.e. CFls, Fridges, LED exit signs, showerhead), the assumptions from that report were utilized. For measures not included in that report but available in the 2006 OEB Measures and Assumption list, this reportwas used. For MUA and Building Automation system, the savings from the SHSC post audits were utilized.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Time of Use Pilot

Description of the program (including intent, design, delivery, partnerships and evaluation):

411 customers participated in the time-of-use (TOU) pilot project. Pilot participants responded to the regulated pricing plan (RPP) TOU rates and were able to shift and conserve part of their load. For a typical pilot customer on the RPP TOU rates, the load-shifting impact approximated 3.7% and conservation impact averaged 3.3%. For the customers on RPP TOU rates with Real Time Monitors, the conservation impact increased to 7.6%

Measure(s):

	Participants		
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	411		
Measure life (years):			
Number of Participants or units delivered life to date	411		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*	$ 190,055	$ 190,055
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 71,107	$ 71,107
Incremental Measure Costs (Equipment Costs)	$ 45,686	$ 45,686
Total TRC costs:	$ 116,793	$ 116,793
Net TRC (in year CDN $):	$ 73,262	$ 73,262
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	1.6	1.6

C. **Results:** (one or more category may apply)

Conservation Programs:

			Cumulative Results:	
Demand savings (kW):	*Summer*	43	43	
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	3,248,037	396,185	3,248,037	396,185
Other resources saved :				
Other (propane):				
Other (water):				-

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 71,107	$ 71,107
	Incentive:		$ -
	Total:	$ 71,107	$ 71,107
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Savings calculations were based on actual savings obtained during this pilot

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** PowerSaverPlus - Online Energy Audits

Description of the program (including intent, design, delivery, partnerships and evaluation):

Over 4,000 customers took the self-administered Online Energy Audit program and received recommendations on how they could lower their usage and electricity bill.

Measure(s):

	Participants		
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	4000		
Measure life (years):			
Number of Participants or units delivered life to date	4000		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		$ -
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 212,670	$ 212,670
Incremental Measure Costs (Equipment Costs)		$ -
Total TRC costs:	$ 212,670	$ 212,670
Net TRC (in year CDN $):		$ -
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	0.0	0.0

C. **Results:** (one or more category may apply)

Conservation Programs:

			Cumulative Results:	
Demand savings (kW):	*Summer*			0
	Winter			
	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):			-	-
Other resources saved :				
Other (propane):				
Other (water):				-

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 212,670	$ 212,670
	Incentive:		$ -
	Total:	$ 212,670	$ 212,670
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Keep Cool Program

Description of the program (including intent, design, delivery, partnerships and evaluation):

Hydro One worked with Clean Air Foundation to sponsor and monitor the Keep Cool program in June, 2006. This program contributed to the implementation of sustainable solutions and helped shave summer peak demand while reducing pollution emissions. In particular, through Keep Cool customers were given the opportunity to retire old RACs for free and receive $25 retailer gift cards. During the three weeks, 2,036 HydroOne customers retired their old RACs and received the gift cards.

Measure(s):

	Room Air Conditioners		
Base case technology:	900 kWh		
Efficient technology:			
Number of participants or units delivered for reporting year:	2,036		
Measure life (years):	4		
Number of Participants or units delivered life to date	2,036		

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		$ 906,043
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		$ 180,732
Incremental Measure Costs (Equipment Costs)		$ 36,648
Total TRC costs:		$ 217,380
Net TRC (in year CDN $):		$ 688,663
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		4.2

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*		2,071
	Winter		0

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):			6,596,640	1,649,160
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:		$ 180,733
	Incentive:		$ 40,720
	Total:		$ 221,453
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Assumptions for Room Air Conditioners -
1. For Base case technology 900 kWh/yr. is used (this is a conservative estimate since average model being sold today is 880 kWh/yr. as per OEB spreadsheet, and current models will be more efficient than the older models being picked up under this program). Average peak demand used is 1.129 kW.
2. For Measure Life 4 years is used. This is based on calculating the remaining life of a recycled unit is the same proportion of technology life as was used for Refrigerators in OEB spreadsheet (6 yrs. remaining life / 19 yrs. total life = approx. 1/3). Thus 1/3 of the technology life of 12 years for a room air conditioner is therefore 4 years.
Incentives shown are based on a $20 per unit for recycling.
Customer incremental equipment costs have been set at $20 since the customer must transport the room air conditioner to the specified retail location on specified date. Benefit to customer is the free recycling of the unit.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** Seasonal LED Light Exchange

Description of the program (including intent, design, delivery, partnerships and evaluation):

The SLED (Seasonal Light Emitting Diode) Program was marketed to residential customers over the holiday season. 105 communities participated in the 2006 SLED Exchange. Due to a Safety Alert related to the SLEDs, Hydro One used retailer gift cards as a replacement for the SLEDs at all exchanges. Costs incurred in 2007 were due to the recall of the Greenlite Christmas lights.

Measure(s):

	Exchange - from 5 Watt bulbs	Exchange- From mini Lights	Exchange - from 7 Watt bulbs
Base case technology:	19 kWh/yr	8 kWh/yr	26 kWh/yr
Efficient technology:	1 kWh/yr	1 kWh/yr	1 kWh/yr
Number of participants or units delivered for reporting year:	4,362	9,378	8,069
Measure life (years):	30	30	30
Number of Participants or units delivered life to date	10,311	14,258	8,069

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		$ 796,490
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 128,108	$ 222,364
Incremental Measure Costs (Equipment Costs)		$ 55,826
Total TRC costs:	$ 128,108	$ 278,190
Net TRC (in year CDN $):	-$ 128,108	
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	0.0	2.9

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*		
	Winter		240

	lifecycle	*in year*	Cumulative Lifecycle	Cumulative Annual Savings
Energy saved (kWh):			16,393,624	546,454
Other resources saved :				
Natural Gas (m3):				
Other (specify):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 128,108	$ 206,049
	Incentive:		$ 217,861
	Total:	$ 128,108	$ 423,910
	Adjustments		
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

Costs incurred in 2007 were due to the recall of the Greenlite Christmas lights.

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a custome are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** PowerSaver Tour

Description of the program (including intent, design, delivery, partnerships and evaluation):

The Power$aver Tour Program was a joint initiative between The Home Depot and Hydro One Networks. This program aimed at promoting and achieving energy conservation savings while reinforcing HydroOne's corporate image. During ten weeks from June until September 2006, a co-branded truck travelled throughout rural Ontario and hosted 11 Hydro One supported summer Festival events where it displayed educational material, gave away product samples and sold energy efficient products. The program was leveraged with another Hydro One complementary program: Cool Shops.

Measure(s):

	CFLs- 27 watts give-aways	CFLs - 15 watts give-aways	Other Products Sold
Base case technology:	232 kWh	139 kWh	
Efficient technology:	63	35	
Number of participants or units delivered for reporting year:			
Measure life (years):	3	4	
Number of Participants or units delivered life to date	9,500	500	13,680

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		$ 1,182,561
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 8,335	$ 287,811
Incremental Measure Costs (Equipment Costs)		$ 105,394
Total TRC costs:	$ 8,335	$ 393,205
Net TRC (in year CDN $):	-$ 8,335	$ 789,356
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	-	3.0

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*		8
	Winter		899

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):			17,981,316	3,170,923
Other resources saved :				
Natural Gas (m3):				
Oil (litres) :				
Propane (litres):				

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):		
Distribution system power factor at beginning of year (%):		
Distribution system power factor at end of year (%):		

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):		
Energy generated (kWh):		
Peak energy generated (kWh):		
Fuel type:		

Other Programs (specify):

Metric (specify):		

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:	$ 8,335	$ 287,811
	Incentive:		$ 34,251
	Total:	$ 8,335	$ 322,062
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

For Programmable Thermostats, participants for each fuel type were calculated using Hydro One Networks customers' fuel shares re-percentaged using the percentage of homes with forced air systems (which was 7 8 %, based on excluding customers using electric baseboard heaters and wood).
The products sold included: Timers, CFLs 15, 23 and 27 Watt, CFL 15 Watt buglights, CFL trilights, 20 Watt par CFL 38 flood lights, Seasonal LEDs, Dimmers, regular Programmable Thermostats.

In 2007 minor costs were incurred that belonged to the 2006 campaign

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a custome are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** MASS MARKET COUPON INITIATIVE - 2005

Description of the program (including intent, design, delivery, partnerships and evaluation):

This mass market residential program featured six energy efficient products for the home - compact fluorescent lighting, seasonal LED lights, programmable thermostats, indoor timers, outdoor timers, and ceiling fans. It was promoted through bill inserts to 1.1 million customers. Coupons with the product discounts were redeemed by the exclusive retailer (Canadian Tire) chosen through RFP process. The program was operated in cooperation with 27 other LDCs including the CLD utilities less Toronto. The program ran from October 1, 2005 to December 31, 2005.

Measure(s):

Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:			
Measure life (years):			
Number of Participants or units delivered life to date			

B. **TRC Results:**

	Reporting Year	Life-to-date TRC Results:
[1] *TRC Benefits ($):*		$ 6,711,739
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):		$ 51,227
Incremental Measure Costs (Equipment Costs)		$ 384,485
Total TRC costs:		$ 465,764
Net TRC (in year CDN $):		$ 6,245,975
Benefit to Cost Ratio (TRC Benefits/TRC Costs):		14.4

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	0	285
	Winter	0	1,789

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):			70,142,678	7,261,874
Other resources saved :				
Natural Gas (m3):			3,806,658	
Other (Oil, Prophane):			4,069,924	

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		
Peak hours dispatched in year (hours):		

Power Factor Correction Programs:

Amount of KVar installed (KVar):			
Distribution system power factor at beginning of year (%):			
Distribution system power factor at end of year (%):			

Line Loss Reduction Programs:

Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			

Distributed Generation and Load Displacement Programs:

Amount of DG installed (kW):			
Energy generated (kWh):			
Peak energy generated (kWh):			
Fuel type:			

Other Programs (specify):

Metric (specify):			

D. **Actual Program Costs:**

		Reporting Year	**Cumulative Life to Date**
Utility direct costs ($):	*Incremental capital:*		
	Incremental O&M:		$ 51,227
	Incentive:		$ 195,797
	Total:		$ 247,024
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Appendix B - Discussion of the Program

A. **Name of the Program:** SmartPak Initiative

Description of the program (including intent, design, delivery, partnerships and evaluation):

The SmartPak Education initiative is a targeted to Grade 5 students as they cover the energy component of the prescribed science curriculum. This initiative encouraged elementary school students and their households to adopt energy conservation practices within Hydro One Networks' service territory.

Measure(s):

	SmartPak distributed		
Base case technology:			
Efficient technology:			
Number of participants or units delivered for reporting year:	6000		
Measure life (years):			
Number of Participants or units delivered life to date	6000		

B. **TRC Results:**

	Reporting Year	**Life-to-date TRC Results:**
[1] *TRC Benefits ($):*	$ 2,548,721	$ 2,548,721
[2] *TRC Costs ($):*		
Utility program cost (excluding incentives):	$ 101,752	$ 101,752
Incremental Measure Costs (Equipment Costs)	$ 165,744	$ 165,744
Total TRC costs:	$ 267,496	$ 267,496
Net TRC (in year CDN $):	$ 2,281,225	$ 2,281,225
Benefit to Cost Ratio (TRC Benefits/TRC Costs):	9.5	9.5

C. **Results:** (one or more category may apply)

Cumulative Results:

Conservation Programs:

Demand savings (kW):	*Summer*	140	140
	Winter	639	639

	lifecycle	*in year*	*Cumulative Lifecycle*	Cumulative Annual Savings
Energy saved (kWh):	27,170,208	3,128,005	27,170,208	3,128,005
Other resources saved :				
Other (propane):	255,830	25,583	255,830	25,583
Other (Gas)	1,271,700	127,170	1,271,700	127,170
Other (water):	1,753,682.40	146,140	1,753,682	146,140

Demand Management Programs:

Controlled load (kW)		
Energy shifted On-peak to Mid-peak (kWh):		
Energy shifted On-peak to Off-peak (kWh):		
Energy shifted Mid-peak to Off-peak (kWh):		

Demand Response Programs:

Dispatchable load (kW):		

Peak hours dispatched in year (hours):			
Power Factor Correction Programs:			
Amount of KVar installed (KVar):			
Distribution system power factor at beginning of year (%):			
Distribution system power factor at end of year (%):			
Line Loss Reduction Programs:			
Peak load savings (kW):			
	lifecycle	*in year*	
Energy savings (kWh):			
Distributed Generation and Load Displacement Programs:			
Amount of DG installed (kW):			
Energy generated (kWh):			
Peak energy generated (kWh):			
Fuel type:			
Other Programs (specify):			
Metric (specify):			

D. **Actual Program Costs:**

		Reporting Year	Cumulative Life to Date
Utility direct costs ($):	*Incremental capital:*		$ -
	Incremental O&M:	$ 101,752	$ 101,752
	Incentive:	$ 165,744	$ 165,744
	Total:	$ 267,496	$ 267,496
Utility indirect costs ($):	*Incremental capital:*		
	Incremental O&M:		
	Total:		

E. Assumptions & Comments:

TRC assumptions are based on the 2006 OEB Measures and Assumption list. The Assumptions for the LED night light is based on the survey result done by Conservation Educational Services.

TRC results are reported in Appendix C under the heading "Education and Communication" , as this program was budgeted under that initiative

[1] Benefits should be estimated if costs have been incurred and the technology has been deployed. Benefits reflect the present value of the measure for the number of units deployed in the year, i.e. the number of units times the net present value per unit benefit specified in the TRC Guide.

[2] For technologies which have not been deployed but for which the LDC has incurred costs, report only the TRC costs on a present value basis. Incentives (e.g. rebates) from the LDC to a customer are not a component of the TRC costs. However, payments made to a third party service provider to run an incentives program are program costs, and are to be included as TRC costs under the "Utility Program Costs" line.

Pollution Probe (PP) INTERROGATORY #8 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

For each of Hydro One's 2008 CDM programmes, please state its forecasted savings (MWh and MW) and its forecasted budget.

Response

For 2008, HON has CDM budgets established through rate MARR funding until April 2008, through Global Adjustment Mechanism funded by OPA and through non rate sources provided by the Ministry of Energy. There are also some costs associated with on-going administration of the CDM work, which are included as part of the 2008 rates application. The HON level of CDM spending for 2008 is currently being negotiated with OPA, and is expected to approach or exceed the level of HON spend in 2007.
Hydro One has approximately $1.4 million worth of expenditures planned for 2008 related to completing programs initiated under MARR funding through to April 30, 2008.

At the time of filing this interrogatory, Hydro One has also made application to OPA for over $11M of CDM program spend to be funded by the Global Adjustment Mechanism, and has additional program applications under development expecting approval from the OPA.

In addition to completing its MARR programs, Hydro One is jointly delivering a pilot, with Enersource Mississauga called Powerhouse. This pilot program provides zero interest financing for residential renewable technologies with funds provided by the Ministry of Energy.

Please see the following table for further details of 2008 CDM program spending.

Program	2008 Forecast			
	Budget	kW Savings	kWh Savings	Target Units
MARR Funded Programs				
Distribution Loss Reduction	$ 800,000			
Time of Use Pilot	$ 130,000			
C/I, Mush Conservation	$ 90,000			
C/I and Load Control	$ 50,000			
Program Management and Research	$ 80,000			
Low Income	$ 50,000			
Residential Load Control	$ 130,000			
Miscellaneous	$ 25,000			
Rate Funded Administration of CDM work				
Maintenance of MARR Funded Programs and Minimum Capability	$ 1,000,000			
OPA Core Programs				
Great Refrigerator Roundup	$ 650,000			20,300
Electricity Retrofit Incentive Program	$ 2,200,000			145
Peaksaver	$ 8,500,000			14,900
Summer Sweepstakes	Program details not yet available.			
Small Commercial Direct Install	Program details not yet available.			
OPA Custom Program Applications				
Double Return	Under development			
Arena Retrofit	Under development			
Compressed Air	Under development			
In Home Display	Under development			
First Nations Retrofit	Under development			
Low Income Retrofit	Under development			
Ministry of Energy Funding				
Powerhouse	$ 500,000			

Pollution Probe (PP) INTERROGATORY #9 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state the number of Hydro One's customers who have enrolled their central air conditioners in Hydro One's PeakSaver progeramme as of December 31, 2007.

Response

As of December 31, 2007 a total of 19,000 Hydro One customers had enrolled in air conditioner load control under various programs and funding. Hydro One also assisted 6 other LDCs with their enrolments, and by December 31, 2007 these additional enrolments totalled 2,000.

Hydro One completed installations for 10,000 enrolled customers by June 15, 2007 under its Smartstat program funded through MARR. An additional 4,634 installations were completed by December 31, 2007 under the Peaksaver program funded by the OPA. The total number of installations is currently in excess of 15,000.

Pollution Probe (PP) INTERROGATORY #10 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state each individual day in 2007 that Hydro One activated its PeakSaver load control system. For each of these days, please also state the demand reductions (MW) that Hydro One obtained.

Response

Hydro One completed 10,000 load control installations by June 15, 2007 under the Smartstat program funded by Hydro One MARR funds. Two load control events were initiated in the summer of 2007; one event on July 26 and another one August 2. These events took place on the hottest days of the summer in response to IESO public appeal to reduce peak load. Each event was initiated at 2:00 pm, for 4 hours, controlling both air conditioning and water heaters. The combined impact of these 10,000 installations was in the range of 10-13MW for each event.

Pollution Probe (PP) INTERROGATORY #11 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state the number of homes and small businesses that have central air conditioners eligible to enroll in Hydro One's PeakSaver programme in Hydro One's franchise areas.

Response

Hydro One estimates that there are approximately 500,000 residential and small commercial customers with central AC in Hydro One territory. However, Peaksaver is offered in the southern part of Ontario only (in summer peaking regions), where Hydro One estimates that there are approximately 470,000 eligible customers.

Pollution Probe (PP) INTERROGATORY #12 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state Hydro One' forecasted number of PeakSaver customers by:

a) June 1, 2008; and

b) December 31, 2008.

Response

Hydro One completed 10,000 load control installations by June 15, 2007 under Smartstat program. We expect to complete an additional 9,000 units by June 1, 2008 under the Peaksaver program, and another 8,000 installations by December 31, 2008. The two programs together (MARR funded and Global Adjustment Mechanism funded) will have a total of 27,000 participants by December 31.

Hydro One is also an aggregator for 6 LDCs that are expected to complete 9,000 installations by December 31, 2008.

Pollution Probe (PP) INTERROGATORY #13 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state Hydro One's forecasted demand response resources (MW) by:

a) June 1, 2008; and

b) December 31, 2008.

Response

a) and b) Hydro One expects to have up to 30 MW of residential demand response under its control by June 2008, and 45 MW by December 31, 2008.

The Smartstat Program, funded by Hydro One, with 10,000 participants, provides 10-13MW of load control capacity. Peaksaver is expected to provide another 9,000 installations representing 9-11MW of load control capacity by June 1, 2008 and another 8,000 installations (8-10MW) by December 31, 2008.

Hydro One is also managing the Peaksaver program for 6 other LDCs as an aggregator, expecting 5,000 installations (5-6 MW capacity) by June 1, 2008, and an additional 4,000 units (4-5 MW) by December 31, 2008.

In addition to the residential sector, HON is proposing a Commercial and Industrial demand response program, Double Return, but this has not yet received approved funding from the OPA.

Pollution Probe (PP) INTERROGATORY #14 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Aside from Hydro One's 2008 CDM programmes proposed as part of this application, please state whether Hydro One sought funding from the OPA for additional CDM programmes. If so, please also describe the proposed programmes and their savings targets (MW and MWh) and budgets.

Response

Please see the response to Exhibit H, Tab2, Schedule 8 for funds sought from the OPA.

Pollution Probe (PP) INTERROGATORY #15 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

With respect to Hydro One's 2008 CDM programmes proposed as part of this application, please state whether Hydro One sought funding from the OPA for more aggressive savings targets (MW or MWh)? If so, please describe the more aggressive savings targets and budgets that Hydro One sought.

Response

Please see the response to Exhibit H, Tab 2, Schedule 8 for funds sought from the OPA.

Pollution Probe (PP) INTERROGATORY #16 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state Hydro One's proposed 2008 savings targets (MW and MWh) and budgets for its Northern York Region CDM programmes.

Response

Hydro One does not have CDM programs aimed solely at Northern York Region. Hydro One proposes to deliver all of the OPA core programs and any accepted custom programs, identified in the response to Exhibit H, Tab 2, Schedule 8, in York Region.

Pollution Probe (PP) INTERROGATORY #17 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state the number of homes and small businesses in the Northern York Region that have enrolled their central air conditioners in Hydro One's PeakSaver programme as of December 31, 2007.

Response

Hydro One had a total of 1,434 participants in load control in York Region by December 31, 2007. Of these 1,154 installations were completed by June 15, 2007, through Smartstat, and another 280 installations were completed under the Peaksaver program.

Pollution Probe (PP) INTERROGATORY #18 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state the number of homes and small businesses in the Northern York Region that have central air conditioners eligible to enroll in Hydro One's PeakSaver programme.

Response

Hydro One estimates that about 13,000 residential and small business customers in York Region with central air conditioners are eligible to participate in Peaksaver.

Pollution Probe (PP) INTERROGATORY #19 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state Hydro One's forecasted number of PeakSaver customers in the Northern York Region by:

a) June 1, 2008; and

b) December 31, 2008.

Response

a) and b) We expect to increase the current number of Peaksaver participants in York Region from 1,434, to approximately 2,000 by June 1, 2008 and further increase by December 31, 2008 to a total of roughly 2500 participants.

Pollution Probe (PP) INTERROGATORY #20 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state Hydro One's forecasted demand response resources (MW) in the Northern York Region by:

a) June 1, 2008; and

b) December 31, 2008.

Response

Between Smartstat and Peaksaver, the potential demand response impact in York Region will be in excess of 2 MW by June 1, 2008 and roughly 2.5 to 3MW by December 31, 2008.

Hydro One has 34 larger Commercial/Industrial in York Region, 15 of which participated in Hydro One's Double return Program in 2007. These 15 customers reduced their summer peak by approximately 800 kW.

Pollution Probe (PP) INTERROGATORY #21 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please provide your best estimates of Hydro One's customers' demands (e.g. residential cooling, commercial cooling, lighting, industrial process machine drive, etc.) in MW at the time of the Ontario electricity system's annual peak demand.

Response

Hydro One's estimated customer demand at the time of the Ontario electricity system's 2007 annual peak demand, which occurred at 4PM on June 26, 2007, is provided below:

Estimated Hydro One's Customer Demand
on June 26, 2007 at 4 PM
(MW)

Customer	Cooling Load	Other Load	Total Load
Retail Customers			
Residential	734	1,378	2,112
Commercial	434	583	1,017
Industrial	0	225	225
Sub-total	1,168	2,186	3,354
Embedded Customers			
Direct			351
LDC			2,676
Sub-total			3,027
All Customers			6,381

Pollution Probe (PP) INTERROGATORY #22 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please provide your best estimates of Hydro One's Northern York Region customers' demands (e.g. residential cooling, commercial cooling, lighting, industrial process machine drive, etc.) in MW at the time of the Ontario electricity system's annual peak demand.

Response

Hydro One's estimated customer demand for Northern York Region at the time of the Ontario electricity system's 2007 annual peak demand, which occurred at 4 PM on June 26, 2007, is provided below:

Estimated Hydro One's Customer Demand
in Northern York Region on June 26, 2007 at 4 PM
(MW)

Customer Class	Cooling Load	Other Load	Total
Residential	37	48	84
Commercial	9	11	20
Industrial	0	13	13
Total	46	71	117

Pollution Probe (PP) INTERROGATORY #23 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

Please state how many dollars of funding Hydro One expects to receive from the OPA pursuant to the OPA's $400 million LDC CDM budget. Please also provide a break-out of the expected funding by year.

Response

The portion of the $400 million LDC CDM Fund Hydro One will receive will depend on customer participation, which custom programs are accepted by the OPA, etc.

OPA Stakeholder consultations known as Program Operations Advisory Group during the months of September 2006 through February 2007, recommended allocation of the $400M to LDCs based on 1% of revenue

Pollution Probe (PP) INTERROGATORY #24 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

If the Board were to direct Hydro One to make a best efforts attempt to costeffectively increase its CDM spending by up to 100% in 2008, please describe the actions Hydro One would take to comply with this directive.

Response

Hydro One has made a best efforts basis to include all identified cost effective CDM programs as part of its funding requested from the OPA for 2008, as outlined in the response to the interrogatory at Exhibit H, Tab 2, Schedule 8. In addition to the over $11 million already requested for 2008, there are still two OPA core programs for which there is insufficient information to estimate funding as well as a number of custom program applications under development.

Pollution Probe (PP) INTERROGATORY #25 List 1

Interrogatory

Issue Number: 6.1
Issue: Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate?

Ref. A/Tab 15/Sch 3- Attachment A- page 26

Are the variances between Hydro One's forecasted and actual electricity system losses recorded in a variance or deferral account?

Response

Hydro One uses the accrual method to record and report its financial results, and assumes that actual losses are the same as the OEB approved Distribution losses. Therefore, no variation exists between approved and actual losses, and consequently there is no variance or deferral account that would record the variation.

Green Energy Coalition (GEC) INTERROGATORY #1 List 1

Interrogatory

Issue 1.2, (OEB CDM Directives) Ex. A-17-1, page 1

In its Decision on HONI's 2006 rates case the Board stated at para. 2.3.9: "The Board expects Hydro One to provide a more sound analysis of CDM program details and reduction objectives in future applications." At 2.3.13 the Board went on to request bottom-up analysis of CDM Impacts and indicated an expectation of an LRAM proposal. The HONI response and exhibit references appear to provide no details of HONI initiated CDM in 2008 and no details of HONI delivered CDM in 2008 nor an LRAM proposal.

a. Please provide details of all CDM programs that HONI is involved in or expects to be involved in during 2008 with load impacts.
b. Please provide copies of all directions, or memorandum containing or describing government direction to HONI in regard to CDM received from 2006 to date.
c. Please provide all information in HONI's possession concerning opportunities for cost-effective CDM among HONI customers that is not currently being pursued in OPA programs.
d. OPA has indicated that it is prepared to receive proposals for funding for LDC initiated CDM programs that may have widespread application. What studies and applications has HONI made in this regard and what effort does HONI anticipate making in 2008?
e. The OEB has indicated that it will consider rate funding of CDM for programs that are not funded by OPA and that are targeted at the distributor's customers. What studies or applications has HONI made in this regard and what effort does HONI anticipate making in 2008?
f. Please provide details of staffing and resources committed to CDM in 2006, 2007 and 2008.

Response

Since HONI utilizes a forward rate year, CDM was adequately reflected in HONI's demand forecast and as such an LRAM application is unnecessary.

Hydro One has completed a bottom-up analysis of CDM impacts, which can be found as Attachment A in Exhibit H Tab 1 Schedule 105.

Please see the response to Exhibit H, Tab 2, Schedule 8 regarding HONI initiated CDM in 2008.

a. Please see the response to Exhibit H, Tab 2, Schedule 8 regarding CDM programs in which HONI expects to be involved in 2008.

b. HONI has not received any directions, memorandum containing or describing government direction specific to HONI in regards to CDM from 2006 to date.

c. Many of the programs already implemented by the OPA are programs that had been piloted, developed and offered by Hydro One. Other cost effective programs are under development by HONI and have been or will be submitted to the OPA as a 'custom program application'; see response to Exhibit H, Tab 2, Schedule 8. We have not commissioned any studies related to additional programs.

Attachment A is a report by Dean C. Mountain, Ph.D., Mountain Economic Consulting and Associates Inc. (Director of the McMaster Institute for Energy Studies) on the in home display pilot run in 2004-2005 under the regulated Price Plan and the results achieved. A subsequent pilot was conducted in 2007 to assess the benefit of in home displays under a TOU plan. The report summarizing these results is expected to be filed with the OEB in April 2008.

d. Please see the response to Exhibit H, Tab 2, Schedule 8 regarding applications that HONI plans to make for custom CDM programs. HONI made an application to OPA for Double Return in October of 2007 that now will have to be resubmitted as part of the OPA custom application process in March 2008. Double Return is a successful customer initiated demand response program for commercial industrial sector that HONI developed and offered with MARR funding, achieving a summer peak reduction of 34 MW in 2007.

e. The Minister of Energy has established a $400 million fund for the express purpose of utility delivered CDM. HONI intends to apply for funding as outlined in the response to Exhibit H, Tab 2, Schedule 8. If any of these programs are turned down for funding by the OPA, HONI will consider applying to OEB at that time.

f. The Strategy and CDM unit within HONI dedicated 4 full time regular staff to CDM, in 2006, and 6 full time regular staff in 2007, 2008. There are additional staff resources available within the company from various disciplines that also support the CDM team (e.g. law, communications, customer care, load forecasting, procurement).

The Impact of Real-Time Feedback on Residential Electricity Consumption: The Hydro One Pilot

Dean C. Mountain, Ph.D.

Mountain Economic Consulting and Associates Inc.

March, 2006

Executive Summary

A pilot study was undertaken by Hydro One to determine whether provision of a real-time feedback device is sufficient to empower residential customers with the information needed to reduce their electricity consumption. The pilot was intended to establish whether use of such a device can help customers save money and be an aid in promoting a "conservation friendly" culture. The objective of the pilot was to assess whether real-time feedback is effective and to determine from usage data if change in behaviour of the participants could be quantified as energy savings. In this study, we have determined a quantitative level of energy savings at the household level that can be linked to the provision of a real-time feedback monitoring device in the home.

In the summer of 2004, participants in Hydro One's Real Time Monitoring Pilot began using real-time monitors. The monitor provided instantaneous feedback on a household's electricity consumption. In comparison to previous pilots and demonstration projects regarding direct feedback provided by real-time monitors, the sample size of the Hydro One pilot is very large. Over four hundred pilot participants and control customers are followed over a 2.5 year period and the sample covers a wide variation in geography and weather. Within the sample there is a great variety of heating, cooling, water heating and appliance configurations, and a rich diversity of household income and demographic characteristics.

The pilot is unique in that only the impact of feedback on consumption information is being tested. Using a panel based econometric methodology, which controls for the traditional ongoing weather, appliance stock and demographic factors influencing electricity consumption, the kilowatt-hour impact of the real-time monitor is quantified.

The results are statistically significant and indicate a significant positive impact on customer usage. Overall, the aggregate reduction in electricity consumption (kWh) across the study sample was 6.5%. The response was persistent and does not decrease over time during the study period. Within the sample, the non-electric heating households showed energy savings of 8.2% with a range in response from 5.1% (for a non-electric water heating house) to 16.7% (for an electric water heating house). We observed that electric heating households are not responding in a significant way to real-time feedback. Separating out the feedback from the electric heating load and the rest of the load would be required to encourage conservation in this sector.

No other price or conservation incentives were given to sample participants. Therefore, the conservation results observed in the pilot are interpreted as the minimum to be garnered in the absence of other possible conservation incentives. Thus, if the real time monitor is used in conjunction with other conservation and/or price measures, an overall average reduction of between 7% and 10% is feasible.

Acknowledgements

This pilot and report has benefited significantly from the support and guidance of Jatin Nathwani. The suggestions and assistance provided by Jatin have been invaluable. The organization of the questionnaires and the preparation of the corresponding data sets were made possible by the careful attention of Carrie Aloussis. Jason Zalev provided valuable computer programming and data organizational support. Stan But has been instrumental in coordinating various administrative aspects of the pilot, beginning with the sample selection and leading to the provision of various data sets during the pilot. The pilot and this report have also benefited greatly from many helpful discussions with Stan But. Finally, the comments of Jim Hall have been very insightful.

Introduction:

The objective of the Hydro One pilot study is to determine whether real-time consumption feedback empowers users sufficiently to effectively reduce energy consumption. As part of this, a quantification of this reduction is undertaken. The Hydro One pilot is unique. It provides a relatively large sample size spread across very diverse geographic regions with respect to weather. It also covers a great variety of heating, cooling, water heating and appliance configuration. There is also a great diversity of household income and demographic characteristics. The pilot evaluation makes use of a relatively rich pre-experiment historical data set (approximately eighteen months) and a parallel control sample that is completely unaware of the pilot.

The principal focus is to test the impact of real-time feedback. Consequently, during the pilot no intrusions with the customer were initiated. Thus, there was no provision of conservation literature, no conservation goal setting, nor any rate incentives.

Customarily residential electricity consumers see their bill either on a monthly, bimonthly, or quarterly basis. Furthermore, even under regular billing there are lags between the billing date and the time of receiving the bill. By the time the customer receives billing information, the connection between the customer's actions with respect to electricity usage and resulting bill is most often lost. In addition, usually no breakdown of consumption by time of day is provided to the customer. And even though a customer has a meter which can be read periodically, it's probably not very accessible and may be perceived as difficult to understand. In fact, electricity is one of the unusual

commodities for which immediate feedback regarding actual consumption does not occur when used.

Our goal was to evaluate how consumers' behavior changes if the flow of consumption information were altered and direct feedback monitoring were provided. The purpose of this report is to quantify the change in kilowatt-hour consumption due to availability of direct feedback information. More specifically, the report evaluates the results of a pilot where customers received direct real-time feedback using the PowerCost Monitor™. The PowerCost Monitor™ involves a display unit that can be placed anywhere in the house. It shows exactly how much electricity is being used at that moment and what it costs. Among other things, it displays current kW and total monthly kWh of the total consumption of the house. The study tests the hypothesis of whether this display of information provides the necessary feedback encouraging conservation.

The feedback tested here falls into the category of "direct feedback" (see King and Delurey (2005)). While this particular pilot, the Hydro One pilot, focuses on an in-home type of display, other types of direct feedback could include displaying consumption on the internet, smart meters operated by smart cards and two-way communication systems showing consumption and cost information, prepayment meters and device monitors inserted between the plug and wall socket on appliances.

More indirect methods of providing feedback involve the utility processing the data and sending the data to the customer. Such methods could include more frequent bills,

sending actual bills (rather than estimates), or comparing year over year estimates normalizing for weather.

In the earlier literature the results of providing feedback information has been somewhat mixed. Many experiments showed success (e.g., McClelland and Cook (1979), Winett, Neale and Grier (1979)). Other studies (e.g., Becker (1978) and Seligman and Darley (1977)) showed failure.

Darby (2001) reviews about thirty-eight feedback studies. Twenty-one of the studies are direct feedback studies. Ten of the twenty-one studies show an impact of less than 10%. The highest savings – in the range of 20% - occurred using a table-top interactive cost and power display unit, a smartcard meter for prepayment of electricity; and an indicator showing cumulative cost of using an electric cooker. Where a special electronic or PC display was not used, direct feedback consisted of frequent readings of a standard household meter, sometimes accompanied by keeping a diary or chart following household use. Some of the feedback studies also provided advice or information regarding potential savings. There the resulting impact was as much as 10%.

For the current Ontario pilot no intervention occurred. Because the objective is to isolate the effect of the provision of more frequent feedback, no further advice or consultation with the household occurred regarding possible conservation actions.

A critical issue in feedback is the time interval between the actual behavior and the feedback information regarding the associated energy consumption. Generally it is felt, the shorter the time interval, the more effective the feedback information (Seligman and Darley (1977) and Winett and Kagel (1984)). Ester (1985) discovered that biweekly feedback is more effective than monthly feedback.

Real-time monitoring and electronic feedback provides feedback with the shortest of time intervals. This now allows implementation of experiments and programs on a large scale without human intervention. Compare this with providing charts and pamphlets (Winett et al. 1978) or Winett and Kagel (1984)). The usage of real time monitors is more cost effective, less disruptive and residents are able to receive feedback at their own discretion without being interrupted on some regular basis.

Once we move to daily and continuous feedback, results vary. McClelland and Cook (1979) show that daily feedback has a significant impact on heating and cooling. However, they found continuous feedback primarily affects energy uses other than heating and cooling. In fact, the greatest conservation occurred in months of moderate weather.

The Technology:

In the Hydro One Pilot the instantaneous feedback is provided by the PowerCost Monitor™ manufactured by Blue Line Innovations Inc. This monitor has many features designed to provide the homeowner with information regarding their electricity

consumption. The monitor that was used in this pilot displayed consumption in dollars per hour, total dollars and predicted dollars. Consumption was also displayed in current kWh, total kWh and predicted kWh. In addition to these features, the user was also able to view the current CO^2 emissions, total CO^2 emissions and predicted CO^2 emissions, as well as the temperature. The monitor is completely portable and can be carried from room to room.

In addition to the in-home device itself, the monitor, there is also a transmitter. The transmitter is attached to an existing electro-mechanical utility meter with a ring clamp. The transmitter tracks the electricity consumed by counting the turns of the meter disk. The transmitter continuously sends a wireless signal to the in-home device which displays the consumption in real-time.

The Pilot:

In order to quantify the impact with a desired level of statistical accuracy, a stratified random sample was designed to cover the geographic territory of Hydro One and to cover a wide variety of consumption patterns. The stratification was based on Dalenius Hodges and Neyman allocation techniques. Within each region, six kWh strata were chosen. The original sample is comprised of 500 customers who were to be given the real time monitor and 52 control customers who were not to be given the real-time monitor. The stratification is shown in Table 1. The sample size is sufficiently large such that even if the study is left with 50% usable data (due to attrition, technical difficulties, lack of

billing data or lack of customer information) accuracy at the 95% level of significance is guaranteed.

With previous annual billing data, a list of possible participants for the pilot, falling into each of the six strata, was used for telephone recruitment. Customers whose meters were not 7.2 kHz and also those who lived in apartments, condominiums, town homes and row homes were excluded from the pilot. During the telephone recruitment, additional screening was used to eliminate those customers who planned to move within six months, those who were seasonal customers, those who lived in a triplex, four-plex or six-plex, those who were renters, as well as those whose meters were located inside the house. After verifying that the customer was eligible (subject to the above restrictions), the real time monitor was offered to the customer. The original rejection rate was less that 2%. Real-time monitors were then given to the pilot participants between July, 2004 and September, 2004.

Evaluation:

In order to assess the impact of the real-time monitor on kWh usage, the kWh usage is monitored from the date of initial usage until September, 2005. To enhance accuracy of the kWh monitoring, once the real-time monitor was given to the customer, monthly reads of the meter occurred. Billing data was also collected for up to 18 months for all pilot participants prior to initial usage of the real-time monitor. However, during this pre-pilot period, generally the billing data was not collected as frequently; most often it was collected quarterly.

Table 1: Real-Time Pilot Stratification

Eastern Region-Peterborough

kWh	Real-Time Group	Control
0 - 6000	23	2
6000-10500	16	1
10500-16500	25	3
16500-24000	18	2
24000-40000	26	3
> 40000	17	2
Total	125	13
Grand Total	138	

Northern Region-Timmins

kWh	Real-Time Group	Control
0 - 4500	20	2
4500-9000	19	2
9000-13500	18	2
13500-22500	30	3
22500-35000	18	2
> 35000	20	2
	125	13
	138	

Western Region-Lincoln

kWh	Real-Time Group	Control
0 - 6000	23	2
6000-10500	17	2
10500-16500	26	3
16500-24000	19	2
24000-40000	22	2
> 40000	18	2
Total	125	13
Grand Total	138	

Central Region-Barrie

kWh	Real-Time Group	Control
0 - 6000	12	1
6000-12000	14	2
12000-19500	16	2
19500-30000	13	1
30000-50000	11	1
> 50000	14	1
	80	8

Central Region-Hydro One Brampton

kWh	Real-Time Group	Control
0 - 6000	7	1
6000-12000	8	1
12000-19500	9	1
19500-30000	7	1
30000-50000	6	0
> 50000	8	1
Total	45	5
Grand Total	50	

Because the customer is being followed, including the pre-experiment period, for around two and a half years, it is important that weather is controlled for, and that demographic and appliance changes in the residence are accounted for. With respect to weather, daily heating degree day and cooling degree day information, collected from the relevant local weather station, is matched with billing cycles of the pilot participants. As well, three questionnaires were administered, one at the beginning of the pilot, one at the midpoint and one at the end. All questionnaires sought information on dwelling characteristics (such as square footage, age of dwelling, etc.), appliance holdings, and demographic characteristics. The first questionnaire also looked back to obtain historical information covering previous years regarding appliance/demographic characteristics and changes during that time. Because the participants' billing consumption is continually monitored, it is critical that any change in dwelling/appliance/demographic characteristics are recorded over the pre-pilot and pilot period.

For the purpose of measuring possible conservation effects due to the use of the real-time monitor, it is important to specify a model which controls for other factors influencing electricity consumption in order that the real-time feedback effect can be isolated. There are three aspects which contribute to this. The first aspect is that each participant is being monitored on a before- and after- basis. The second aspect is that there is a parallel control sample who did not receive such a monitor. One reason for this parallel control sample, is that it allows control for possible conservation that may have occurred anyways during the sample time period. The third aspect is to construct a well-specified

model that controls for the electricity consumption responding to traditional factors such as weather, appliance configuration and household demographics.

Following the pilot and control participants through time provides us with panel data. The panel data provides the necessary input for analysis by an appropriately specified econometric model.

The Model:

Before describing some of the data considerations and the estimation procedure, a precise description of the model follows. The following description provides a description of a model of daily kWh consumption for household i at time t. Because the billing cycle varies through time for each participant and across participants, all billing data is normalized by number of days in the billing period.

Depending on the appliance and heating/cooling configuration of a household, the total consumption in the absence of the real time monitor is envisaged to be a function of variables influencing electric heating usage, electricity water heating usage, air conditioning usage, and other appliance usage. In addition there may be time trend related factors perhaps related to prices and overall conservation attitudes that may influence electricity usage. All of these factors described in the following specification are in the functions $f^1(\cdot,\cdot), f^2(\cdot,\cdot), f^3(\cdot,\cdot), f^4(\cdot,\cdot), and\ f^5(\cdot,\cdot)$. Once the real-time monitor is used by the customer, further variables may come into play. They are captured in the function $g(\cdot,\cdot)$.

More precisely, the logarithm of daily kWh consumption for household i at time t is $\ln y_{it}$, where $\ln y_{it}$ is decomposed as follows

$$\ln y_{it} = f^1(\underset{\sim}{x}^1_{it}, \underset{\sim}{\alpha}) + f^2(\underset{\sim}{x}^2_{it}, \underset{\sim}{\beta}) + f^3(\underset{\sim}{x}^3_{it}, \underset{\sim}{\gamma}) + f^4(\underset{\sim}{x}^4_{it}, \underset{\sim}{\delta}) + f^5(\underset{\sim}{x}^5_{it}, \underset{\sim}{\lambda}) + g(\underset{\sim}{z}_{it}, \underset{\sim}{\theta}) + \mu_{it}$$

for those households with some part of their heating load serviced by electricity,

$f^1(\underset{\sim}{x}^1_{it}, \underset{\sim}{\alpha}) = \underset{\sim}{x}^{1\prime}_{it} \underset{\sim}{\alpha}$, with parameter vector $\underset{\sim}{\alpha}$, is a linear function of a vector of independent variables ($\underset{\sim}{x}^1_{it}$) influencing the electric heating load, in the absence of the real time monitor;

for those households with electricity water heating load,

$f^2(\underset{\sim}{x}^2_{it}, \underset{\sim}{\beta}) = \underset{\sim}{x}^{2\prime}_{it} \underset{\sim}{\beta}$, with parameter vector $\underset{\sim}{\beta}$, is a linear function of a vector of independent variables ($\underset{\sim}{x}^2_{it}$) influencing the electric water heating load, in the absence of the real time monitor;

for those households with some air conditioning load,

$f^3(\underset{\sim}{x}^3_{it}, \underset{\sim}{\gamma}) = \underset{\sim}{x}^{3\prime}_{it} \underset{\sim}{\gamma}$, with parameter vector $\underset{\sim}{\gamma}$, is a linear function of a vector of independent variables ($\underset{\sim}{x}^3_{it}$) influencing the electric air conditioning heating load, in the absence of the real time monitor;

for all households,

$f^4(\underset{\sim}{x}^4_{it}, \underset{\sim}{\delta}) = \underset{\sim}{x}^{4\prime}_{it}\,\underset{\sim}{\delta}$, with parameter vector $\underset{\sim}{\delta}$, is a linear function of a vector of independent variables ($\underset{\sim}{x}^4_{it}$) influencing the remaining electricity loads, in the absence of the real time monitor;

for all households,

$f^5(\underset{\sim}{x}^5_{it}, \underset{\sim}{\lambda}) = \underset{\sim}{x}^{5\prime}_{it}\,\underset{\sim}{\lambda}$, with parameter vector $\underset{\sim}{\lambda}$, is a linear function of a vector of trend related independent variables ($\underset{\sim}{x}^5_{it}$) influencing the total electricity load, in the absence of the real time monitor;

for all households using the real time monitor,

$g(\underset{\sim}{z}_{it}, \underset{\sim}{\theta}) = \underset{\sim}{z}'_{it}\,\underset{\sim}{\theta}$, with parameter vector $\underset{\sim}{\theta}$, is a linear function of a vector of independent variables ($\underset{\sim}{z}_{it}$) influencing the electricity load, in the presence of the real time monitor;

μ_{it} is a stochastic error with possible autocorrelation and heteroskedasticity.

Briefly, the various components reflect the critical factors that influence the corresponding usage.

Electric heating formulation:

For those houses with some part of the dwelling heated with electricity, we would expect the size of the house (measured in square feet), the age of the dwelling, the weather

(measured in heating degree days), the number of residents, and income to probably matter.

$$f^1(\underset{\sim}{x}^1_{it}, \underset{\sim}{\alpha}) = \underset{\sim}{x}^{1\prime}_{it}\,\underset{\sim}{\alpha} =$$

$$\left(\alpha_0 + \alpha_1 NR_{it} + \alpha_2 IN_{it} + \alpha_3 A1_i + \alpha_4 A2_i + \alpha_5 A3_i + \alpha_6 A4_i + \alpha_7 A5_i + \alpha_8 A6_i\right) \bullet DF_{it} SQ_{it} HDD_{it}$$

where

DF_{it} is the proportion of the dwelling heated by electricity at time t,

HDD_{it} is the normalized (per day) heating degree days (with reference temperature 18 degrees Celsius) measured during time t,

SQ_{it} is the square footage of the dwelling,

NR_{it} is the number of residents in the household,

IN_{it} is household income,

$$A1_i = \begin{cases} 1 & \textit{dwelling built between } 1940 \textit{ and } 1969 \\ 0 & \textit{otherwise} \end{cases},$$

$$A2_i = \begin{cases} 1 & \textit{dwelling built between } 1970 \textit{ and } 1986 \\ 0 & \textit{otherwise} \end{cases},$$

$$A3_i = \begin{cases} 1 & \textit{dwelling built between } 1987 \textit{ and } 1990 \\ 0 & \textit{otherwise} \end{cases},$$

$$A4_i = \begin{cases} 1 & \textit{dwelling built between } 1991 \textit{ and } 1993 \\ 0 & \textit{otherwise} \end{cases},$$

$$A5_i = \begin{cases} 1 & dwelling\ built\ between\ 1994\ and\ 1998 \\ 0 & otherwise \end{cases},$$

$$A6_i = \begin{cases} 1 & dwelling\ built\ since\ 1999 \\ 0 & otherwise \end{cases}.$$

Electric water heating formulation:

For electric water heating, the number of residents, the age composition, income and hot water related appliances matter.

$$f^2(\underset{\sim}{x}^2_{it}, \underset{\sim}{\beta}) = \underset{\sim}{x}^{2\prime}_{it}\ \underset{\sim}{\beta} =$$
$$\left(\beta_0 + \beta_1 NR_{it} + \beta_2 APDW_{it} + \beta_3 APCW_{it} + \beta_4 IN_{it} + \beta_5 NAG1_{it} + \beta_6 NAG2_{it}\right) \bullet DW_{it}$$

where

$$DW_{it} = \begin{cases} 1 & if\ dwelling\ has\ electricity\ water\ heating \\ 0 & otherwise \end{cases},$$

NR_{it} is the number of residents in the household,

$APDW_{it}$ is the wattage of all dishwashers in the dwelling,

$APCW_{it}$ is the wattage of the clothes washing machines in the dwelling,

IN_{it} is household income,

$NAG1_{it}$ is the number of household members less than or equal to 14

$NAG2_{it}$ is the number of household members greater than or equal to 15 and less than or equal to 19.

Air conditioning formulation:

For air conditioning participants, the square footage, the weather (measured by cooling degree days), the number of residents and income may matter.

$$f^3(\underset{\sim}{x}^3_{it}, \underset{\sim}{\gamma}) = \underset{\sim}{x}^3_{it}{}' \underset{\sim}{\gamma} = (\gamma_0 + \delta_1 NR_{it} + \delta_2 IN_{it}) \bullet (DA_{it} SQ_{it} CDD_{it})$$

where

DA_{it} is the proportion of the dwelling air conditioned at time t,

CDD_{it} is the normalized (per day) cooling degree days (with reference temperature 22 degrees Celsius) measured during time t,

SQ_{it} is the square footage of the dwelling,

NR_{it} is the number of residents in the household,

IN_{it} is household income.

Other electricity load formulation:

For the other electricity component, the number of residents, the income, and the stock of appliances should matter.

$$f^4(\underset{\sim}{x}^4_{it}, \underset{\sim}{\delta}) = \underset{\sim}{x}^4_{it}{}' \underset{\sim}{\delta} = \delta_0 + (\delta_1 + \delta_2 NR_{it} + \delta_3 IN_{it}) \bullet APT_{it} + \delta_4 DPHE_{it} + \delta_5 APPP_{it} + \delta_6 APONM_{it}$$

where

NR_{it} is the number of residents in the household,

IN_{it} is household income,

APT_{it} is the total wattage of the following appliances: clothes dryer, dishwasher, freezer, microwave, mini-bar, personal computer, range, refrigerator, television, washing machine;

$DPHE_{it}$ is the wattage of an in-ground pool heater owned by household i at time t,

$APPP_{it}$ is the wattage of the pool pump if owned by household i at time t,

$APONUM_{it}$ is the total number of saunas, hot tubs and whirlpools

Trend related formulation:

The trend related formulation is very simple. There is a dummy variable for summer months, a dummy variable for winter months, and a time trend index. If there are conservation impacts happening, regardless of the usage of the real time monitor, the coefficient corresponding to the time trend index would be expected to be negative and statistically significant from zero.

$$f^5(\underset{\sim}{x}_{it}^{5}, \underset{\sim}{\lambda}) = \underset{\sim}{x}_{it}^{5\prime} \underset{\sim}{\lambda} = \lambda_1 DSM_{it} + \lambda_2 DWN_{it} + \lambda_3 \sqrt{T_{it}}$$

where

DSM_{it} is the proportion of billing days for time t in the months of June, July and August,

DWN_{it} is the proportion of billing days for time t in the months of December, January and February,

T_{it} is a time index.

Real-time monitor impact formulation:

Variables influencing the feedback include the configuration of space heating, water heating and air conditioning, income, education and the age distribution of household members. Furthermore, it is desirable to test whether there is any attenuation of impact during the pilot. In other words, does the feedback response diminish or increase during the time of using the real-time monitor? Because of the extreme variation in cold weather across the sample in the winter months, in addition to modeling the feedback as a linear term involving heating degree days interacted with proportion of dwelling heating by electricity, a nonlinear term involving the square root of heating degree days is also added.

$$g(\underset{\sim it}{z}, \underset{\sim}{\theta}) = \underset{\sim it}{z}' \underset{\sim}{\theta} =$$
$$\left(\begin{array}{l} \theta_0 + \theta_1 DF_{it}(1 - DSM_{it}) + \theta_2 DF_{it} HDD_{it} + \theta_3 DF_{it}\sqrt{HDD_{it}} + \theta_4 DW_{it} + \theta_5 DA_{it} CDD_{it} + \\ \theta_6 IN_{it} + \theta_7 ED_{it} + \theta_8 NAG4_{it} + \theta_9 \sqrt{TD_{it}} \end{array} \right) \bullet D_{it}$$

where

DSM_{it} is the proportion of billing days for time t in the months of June, July and August,

DF_{it} is the proportion of the dwelling heated by electricity at time t,

HDD_{it} is the normalized (per day) heating degree days (with reference temperature 18 degrees Celsius) measured during time t,

CDD_{it} is the normalized (per day) cooling degree days (with reference temperature 22 degrees Celsius) measured during time t,

$$DW_{it} = \begin{cases} 1 & if\ dwelling\ has\ electricity\ water\ heating \\ 0 & otherwise \end{cases},$$

DA_{it} is the proportion of the dwelling air conditioned at time t,

IN_{it} is household income,

$$ED_{it} = \begin{cases} 1\ if\ the\ highest\ level\ of\ education\ in\ the\ household\ corresponds\ to\ either\ a\ college\ \text{deg}ree, \\ \quad a\ trades\ diploma, or\ a\ university\ \text{deg}ree \\ 0\ otherwise \end{cases}$$

$NAG4_{it}$ is the number of household members 65 and over

TD_{it} is the time in days since the real-time-monitor was installed

Data Considerations:

After assembling the data, a number of issues had to be handled. During the initial phase of the pilot study, there were technical difficulties with the device that needed to be corrected.[1] For those observations, the affected data were dropped from the analysis. The billing period corresponding to installation is dropped because the observation is mixed in nature. The first part of the billing period corresponds to no usage of the real-time monitor and the second part of the billing period corresponds to usage of the real-time monitor.

Only actual meter reads were used. This is particularly relevant to the pre-pilot period where estimated bills were sometimes sent to customers. Moreover, there were some sample participants who did not respond in filling out any of the three questionnaires. If a participant responded to only the first or first and second questionnaires, they were

[1] Technical problems fell into the following categories: installation problems (15%), battery issues (30%), missing transmitter (1%), dropped receivers (3%), potting issues (29%), range issues (10%) and other and unknown (12%).

followed as long as questionnaire data was available. If a participant moved during the pilot, the participant was followed up until their departure. After the above data inspection there were 5015 usable observations. This consisted of 382 pilot participants and 42 control customers.

Because billing cycles are customer- and time-specific, all heating and cooling degree day information was matched precisely to the billing cycle.

For many of the already cited reasons, it becomes clear very quickly that the resulting data set is comprised of observations separated by multiple time lags. Even for one customer, sometimes (either due to variation in billing cycles, long periods between actual reads, dropped observations for reasons described above) the lags between midpoints of actual reads vary. For example, in looking at the distance between observations for one participant, there may be one month, two months or even three months.

The underlying error is assumed to be AR(1). That is $u_{it} = \rho u_{i,t-1} + e_{it}$. The selection of the model's parameters is based on maximizing the likelihood function. Where possible, except for starting observations, we formulate the model in differences between consecutive observations. The advantages of this technique with respect to handling possible selection bias are outlined in Ham, Mountain and Chan (1997). To account for the variation in lags across the sample, a concentrated likelihood function in the spirit of Beach and MacKinnon (1978) is formulated.

Denote $\underset{\sim}{X}_{it}' = \left(\underset{\sim}{x^1}_{it}', \underset{\sim}{x^2}_{it}', \underset{\sim}{x^3}_{it}', \underset{\sim}{x^4}_{it}', \underset{\sim}{x^5}_{it}', \underset{\sim}{z}_{it}' \right)$ and $\underset{\sim}{\tau}' = \left(\underset{\sim}{\alpha}', \underset{\sim}{\beta}', \underset{\sim}{\gamma}', \underset{\sim}{\delta}', \underset{\sim}{\lambda}', \underset{\sim}{\theta}' \right)$.

Denote k_{it} as the distance in months between the observation at time t and $t-1$.

Denote A as the set of observations corresponding to the initial time period for which we have data on a household. Let the number of observations in set A be $\overline{A}$.

Denote B as the set of observations where the distance (measured in months) since the last observation corresponds to the lagged distance. Let the number of observations in set B be $\overline{B}$.

Denote C as the set of observations where the distance (measured in months) since the last observation does not correspond to the lagged distance. Let the number of observations in set C be $\overline{C}$.

The sets $A, B,$ and C are mutually exclusive and exhaustive. Thus the total number of observations in these three sets ($\overline{A} + \overline{B} + \overline{C}$) equals N, the total number of observations.

The concentrated likelihood function to be maximized (in terms of $\underset{\sim}{\tau}$ and ρ) is

$$\left[\frac{\overline{A} + \overline{C}}{2} \right] \ln(1-\rho^2) - 0.5 \sum_i \sum_{\substack{t \\ i,t \in C}} \ln(2(1-\rho^{k_{it}})) - 0.5 \sum_i \sum_{\substack{t \\ i,t \in B}} \ln\left(\frac{1-\rho^{2k_{it}}}{1-\rho^2} \right)$$

$$-\frac{N}{2} \left[\begin{array}{l} \displaystyle\sum_i \sum_{\substack{t \\ i,t \in A}} \left(\ln y_{it} - \underset{\sim}{X}_{it}' \underset{\sim}{\tau} \right)^2 + \sum_i \sum_{\substack{t \\ i,t \in B}} \left(\left(\Delta \ln y_{it} - \rho^{k_{it}} \Delta \ln y_{i,t-k_{it}} \right) - \left(\Delta \underset{\sim}{X}_{it}' \underset{\sim}{\tau} - \rho^{k_{it}} \Delta \underset{\sim}{X}_{it}' \underset{\sim}{\tau} \right) \right)^2 \\ \displaystyle + \sum_i \sum_{\substack{t \\ i,t \in C}} \left(\Delta \ln y_{it} - \Delta \underset{\sim}{X}_{it}' \underset{\sim}{\tau} \right)^2 \end{array} \right]$$

Results:

Reasonableness of Model:

The above concentrated likelihood function is maximized using a grid search involving ρ. Before arriving at the final model, we tested whether the demographic/income and attenuation effects pertaining to the real-time monitor are zero.[2] That is, $H_0 : \theta_6 = \theta_7 = \theta_8 = \theta_9$. This hypothesis could not be rejected at the 5% level of significance ($\chi^2(4) = 0.92 < 9.49 = \chi^2(4)^{crit}_{.05}$). This is also consistent with the findings of Brandon and Lewis (1999), who also found for households in Bath that income and demographic factors had no impact on the responsiveness of the monitor.[3] The estimated parameters corresponding to the maximum likelihood corresponding to the final model are in Table 2. The optimal ρ is -0.488. The autocorrelation is statistically significant at the 5% level of significance ($\chi^2(1) = 88.00 > 3.84 = \chi^2(1)^{crit}_{.05}$). We also tested for heteroskedasticity of the error (e_{it}), where the heteroskedasticity was modeled as a function of the electric heating/electric water heating/air conditioning configuration. Using White's test, it appears that heteroskedasticity is not present ($\chi^2(3) = 7.52 < 7.81 = \chi^2(3)^{crit}_{.05}$).

A quick look at the parameters of the model shows most parameters with relatively low standard errors. The model seems to be well specified. $R^2 = 0.9439$. This is a very good fit for such panel data.

[2] In some preliminary analysis an attitudes-conservation index interacted with the usage of the real-time monitor (D_{it}) was include as an explanatory variable. However, this variable was not statistically significant.

[3] Like the results from this pilot, they found income and demographic factors were useful to predict historical energy consumption.

Table 2: Estimated Parameters of Final Model

	Scaling Factor	Parameter	Standard Error
		Electric Heating Parameters (All variables interacted with $DF_{it}SQ_{it}HDD_{it}$)	
α_0	10^{-4}	0.5160	0.0454
$\alpha_1 : NR$	10^{-6}	-0.6208	0.2898
$\alpha_2 : IN$	10^{-10}	-0.4592	0.1077
$\alpha_3 : A1$	10^{-5}	-0.2638	0.0448
$\alpha_4 : A2$	10^{-5}	-0.2415	0.0444
$\alpha_5 : A3$	10^{-4}	-0.3290	0.0448
$\alpha_6 : A4$	10^{-4}	-0.2889	0.0461
$\alpha_7 : A5$	10^{-4}	-0.3254	0.0521
$\alpha_8 : A6$	10^{-5}	-0.1220	0.0674
		Electric Water Heating Parameters (All variables interacted with DW_{it})	
β_0	10^{0}	0.4932	0.1191
$\beta_1 : NR$	10^{-1}	0.2615	0.3047
$\beta_2 : APDW$	10^{-2}	-0.1163	0.0256
$\beta_3 : APCW$	10^{-2}	-0.2062	0.1101
$\beta_4 : IN$	10^{-5}	0.1887	0.0665
$\beta_5 : NAG1$	10^{-1}	-0.7831	0.3572
$\beta_6 : NAG2$	10^{-1}	0.2531	0.3913
		Air Conditioning Parameters (All variables interacted with $DF_{it}SQ_{it}CDD_{it}$)	
γ_0	10^{-3}	0.1607	0.0200
$\gamma_1 : NR$	10^{-6}	0.7212	3.3800
$\gamma_2 : IN$	10^{-9}	-0.5542	0.0794

Table 2 (continued)

	Scaling Factor	Parameter	Standard Error
		Other Electricity Load Parameters	
δ_0	10^0	2.5464	0.0799
$\delta_1 : APT$	10^{-4}	0.8942	0.1774
$\delta_2 : NR \cdot APT$	10^{-4}	0.1679	0.0303
$\delta_3 : IN \cdot APT$	10^{-9}	0.1980	0.0888
$\delta_4 : DPHE$	10^{-1}	0.6936	0.5624
$\delta_5 : APPP$	10^{-3}	0.1522	0.0130
$\delta_6 : APONM$	10^0	0.1281	0.0235
		Trend Related Parameters	
$\lambda_1 : DSM$	10^{-1}	-0.4691	0.1555
$\lambda_2 : DWN$	10^0	0.2041	0.0120
$\lambda_3 : \sqrt{T}$	10^{-2}	0.7852	1.3930
		Real-time Monitor Impact Parameters (All variables interacted with D_{it})	
θ_0	10^{-1}	-0.5169	0.2770
$\theta_1 : (1 - DSM)$	10^0	-0.1193	0.0712
$\theta_2 : DF \cdot HDD$	10^{-2}	-0.7315	0.6196
$\theta_3 : DF \cdot \sqrt{HDD}$	10^0	0.1049	0.0465
$\theta_4 : DW$	10^0	-0.1307	0.0428
$\theta_5 : DA \cdot CDD$	10^{-4}	-0.3141	0.1533

R^2: 0.9439
Log of the Likelihood Function: -15833.42
Number of Observations: 5015

For the electric heating model pertaining to no presence of real time monitor, as expected, the higher the number of residents in the household, the lower is the consumption. This is an effect commonly observed in the conditional demand literature. Not unexpectedly, the age of the dwelling seems to matter in explaining electric heating consumption. Furthermore, the bigger the house, the more electricity is used (e.g., α_0 and the other α parameters are statistically significant from zero). Interestingly, the income coefficient is negative both in the electric heating submodel and in the air conditioning submodel. Perhaps, in economic terms, one could characterize the electricity required for heating and cooling is such a necessity that it is an inferior good. However, this may also be related to the idea that the higher the level of income, the more investment made by households in insulation and weather proofing of the dwelling (and for new home purchases, this means a more energy efficient dwelling in terms of heat or cooling loss), ultimately leads to less electricity used in heating and cooling.

For the air-conditioning submodel, the higher the number of residents and the higher the square footage, the higher is the air conditioning load. This is to be expected. The age profile of the dwelling was also examined (not shown) as a possible set of explanatory variables for air conditioning load. However, in our sample we found the age of dwelling didn't seem to matter regarding air conditioning load.

Going back to the electric water heating load, the number of residents and the level of income positively affect electricity usage. But, a negative adjustment must be made for the number of children less than or equal to fourteen. Interestingly, higher dishwasher wattage shows a significantly negative impact on electric water heating. Perhaps

dishwashers with higher wattage show more efficiency in conserving electric hot water. As well, there may be a high correlation with the dishwasher wattage and demographics in the house which we are not capturing explicitly.

For the other electricity load (base load) parameters, all coefficients of explanatory variables are positive and all but one is statistically significant from zero. Generally, the greater the number or appliances, the higher is the electricity consumption. In particular, the number of saunas, hot tubs and whirlpools along with the presence of a pool pump significantly increase household load. As well, as income and the number of residents increase, base load consumption increases.

With respect to trend related variables, while there is a significant seasonal impact aside from weather ($\lambda_1 < 0, \lambda_2 > 0$), there are no quantifiable underlying trend conservation effects.

The Impact of the Real Time Monitor

Does the real-time monitor affect consumption? This corresponds to testing $H_0 : \theta_0 = \theta_1 = \theta_2 = \theta_3 = \theta_4 = \theta_5$. This hypothesis is rejected at the 5% level of significance ($\chi^2(6) = 42.70 > 12.59 = \chi^2(6)^{crit}_{.05}$). The statistical significance of $\theta_0, \theta_1, \theta_2, \theta_3, \theta_4, and\ \theta_5$ illustrates that the real-time monitor has a significant impact on customer behavior. Furthermore, the critical determinants of the responsiveness are the electric heating/electric water heating/air conditioning configuration. This is shown in Table 3. Table 3 shows percentage kWh savings and percentage impacts due to real-time

Table 3: Percentage Impact of Real-Time Monitor: By Heating-Water Heating-Air Conditioning Configurations

	Sample Estimates							
Electric Heating: (Percentage of house heated with electricity: DF)	100	100	0	0	0	0	0<DF<100	0
Electric Water Heating:	Yes	Yes	Yes	Yes	No	No	---	---
Air Conditioning: (Percentage of house cooled: DA)	100	0	100	0	100	0	0<DA<100	$0 \leq DA \leq 100$
Sample Proportion	0.045	0.068	0.050	0.076	0.262	0.115	0.385	0.579
Square Footage	2876	1619	2191	1908	2404	1758	1912	2100
Number of Residents	2.99	2.79	2.94	3.00	3.23	2.91	2.78	3.04
Income	68822	70042	77706	71174	95165	62981	63889	79792
kWh before real-time monitor	34418	24219	16256	13960	12363	9945	17485	12106
Change in kWh due to real-time monitor	-298.6	-281.6	-2720.6	-2336.2	-624.6	-502.4	-1015.8	-987.6
Percentage Response (%)	-0.87	-1.16	-16.74	-16.74	-5.05	-5.05	-5.81	-8.16

monitoring. The impacts are calculated at sample averages. Sample averages for square footage, number of residents and income are reported. For example, when DF=1, DW=1 and DA=1 (an all-electric house) the impact is -0.87%. Contrast this with DF=0, DW=1 and DA=1 (electric water heating and air conditioning but no electric heating), where the impact is -16.74%.

Looking at the first six columns of Table 3, it is clear that the largest impact occurs for customers with electric water heating and without electric heating (-16.74%). Admittedly, the coefficients in Table 2 show that the extra conservation effect is statistically significant for air conditioning households in comparison to non-air conditioning households. However, numerically the difference is less than the second decimal point and consequently, the percentage impacts are not much different. The participants without electric water heating and without electric heating show reductions of 5.05%. Both of these impacts are statistically significant at the 95% level of significance. Notice that because of the log-linearity of the specification, and because the air conditioning response is numerically small, the conservation percentage impact for both electric water heating (and no electric heating) households is identical for customers with and without air conditioning. This is also true for non-electric water heating households, with and without air conditioning.

What is not significant is the response of electric heating houses. The seventh column shows the impact on participants with some portion (<100%) of their house heated

electrically or with air conditioning. Here the impact is significant and is -5.81%. For those participants with no electric heating (either partial or complete) the reduction is 8.16%. Over the entire sample, the average reduction is 6.50%. Excluding the electric heating participants, these percentage responses are in the range of "5% or more" observed by Darby (2001) in her survey of direct feedback experiments.[4] The Ontario pilot's results are very consistent with the 7% self-monitoring impacts observed in the relatively small Maryland feedback sample (Winett, Neale and Grier (1979)).

The Ontario results are below the 10% reduction observed in four programs surveyed by Darby (2001) where information about conservation was provided to households. But again, it is to be noted that in the Ontario pilot no such conservation information was given to participants, and the Ontario pilot covers a relatively large diverse group of participants with respect to heating, cooling and water heating mix. However, this pilot's estimate for electric heating response does not compare with the 12.9% savings observed by Dobson and Griffin (1992).

With respect to electric heating households, it appears that because the electric heating load completely overwhelms (maybe as much as 80% of the load in the winter) the rest of the dwelling's electricity load, the participant is probably unable to detect any of their non-heating conservation actions. Consequently, the feedback provides no indication of reward for conservation efforts. The Dobson and Griffin (1992) pilot provided the

[4] On the other hand, the Ontario pilot's response is below the 12.3% reduction fund in the electronic gas monitoring experiment in the Netherlands (Van Houwelingen and Van Raaij (1989)) where in addition to receiving daily feedback about natural gas use the customer receives comparisons with conservation goals set at the beginning of the pilot.

customer with instant feedback on individual sub-metered loads (e.g., heating, water heating, air conditioning, range, etc.) The results of the current pilot together with the Dobson and Griffin (1992) study would probably suggest that while submetering of all loads is not necessary, at least separating the feedback from electric heating load from the rest of the loads would be worthwhile for the customer.

Table 4 provides another perspective. Here, there is a comparison of the savings for a house of identical size and identical demographics and appliance configuration in each of the geographic regions of the pilot. For example, in Lincoln (the southern most region of our sample), while the electric heating household show conservation impacts of 3.37%, the non-electric heating impact averages 6.67%. The reason that these electric heating households show more of a conservation impact is that they have relatively less heating degree days than the rest of the sample. Again, the electric water-heating participants show an impact of 16.74%. The remaining part of Table 4 examines the impacts in each of the other five regions. With the exception of Brampton, the impacts for non-electric heating houses are greater than those of Lincoln. As we move to colder and colder climates (i.e., to Peterborough and Timmins), the impact on electric heating houses becomes insignificant (either insignificantly negative or positive). This is in keeping with the findings of McClelland and Cook (1979) in their examination of twenty-five North Carolina all-electric homes. Furthermore, extremes in weather across regions are much more in Ontario. For example, in Lincoln region annual heating degree days is 3650.5, whereas in Timmins annual heating degree days are about 58% greater, totaling 5765.9.

Table 4: Percentage Impact of Real-Time Monitor: By Heating-Water Heating-Air Conditioning Configurations

				By Region in Ontario				
Electric Heating: (Percentage of house heated with electricity: DF)	100	100	0	0	0	0	0<DF<100	0
Electric Water Heating:	Yes	Yes	Yes	Yes	No	No	---	---
Air Conditioning: (Percentage of house cooled: DA)	100	0	100	0	100	0	0<DA <100	$0 \leq DA \leq 100$
				Lincoln				
Square Footage	2099	2099	2099	2099	2099	2099	2099	2099
Number of Residents	3.08	3.08	3.08	3.08	3.08	3.08	3.08	3.08
Income	74692	74692	74692	74692	74692	74692	74692	74692
Annual Heating Degree Days	3650.5	3650.5	3650.5	3650.5	3650.5	3650.5	3650.5	3650.5
Annual Cooling Degree Days	166.6	166.6	166.6	166.6	166.6	166.6	166.6	166.6
kWh before real-time monitor	29720	27400	17684	15391	12298	10704	16835	12598
Change in kWh due to real-time monitor	-1000.1	-689.6	-2959.8	-2575.8	-621.5	-540.7	-946.0	-839.7
Percentage Response (%)	-3.37	-2.52	-16.74	-16.74	-5.05	-5.05	-5.62	-6.67

Table 4 (continued): Percentage Impact of Real-Time Monitor: By Heating-Water Heating-Air Conditioning Configurations

By Region in Ontario

Electric Heating: (Percentage of house heated with electricity: DF)	100	100	0	0	0	0	0<DF<100	0
Electric Water Heating:	Yes	Yes	Yes	Yes	No	No	---	---
Air Conditioning: (Percentage of house cooled: DA)	100	0	100	0	100	0	0<DA<100	$0 \leq DA \leq 100$

Barrie

Square Footage	2292	2292	2292	2292	2292	2292	2292	2292
Number of Residents	2.98	2.98	2.98	2.98	2.98	2.98	2.98	2.98
Income	75225	75225	75225	75225	75225	75225	75225	75225
Annual Heating Degree Days	4220.7	4220.7	4220.7	4220.7	4220.7	4220.7	4220.7	4220.7
Annual Cooling Degree Days	75.4	75.4	75.4	75.4	75.4	75.4	75.4	75.4
kWh before real-time monitor	30294	29342	15642	14726	10825	10190	16416	11757
Change in kWh due to real-time monitor	-332.9	-224.7	-2617.9	-2464.4	-546.9	-514.8	-1210.8	-1025.7
Percentage Response (%)	-1.10	-0.77	-16.74	-16.74	-5.05	-5.05	-7.38	-8.72

Table 4 (continued): Percentage Impact of Real-Time Monitor: By Heating-Water Heating-Air Conditioning Configurations

By Region in Ontario

Electric Heating: (Percentage of house heated with electricity: DF)	100	100	0	0	0	0	0<DF<100	0
Electric Water Heating:	Yes	Yes	Yes	Yes	No	No	---	---
Air Conditioning: (Percentage of house cooled: DA)	100	0	100	0	100	0	0<DA<100	$0 \leq DA \leq 100$

Brampton

Square Footage	2714	2714	2714	2714	2714	2714	2714	2714
Number of Residents	3.38	3.38	3.38	3.38	3.38	3.38	3.38	3.38
Income	107640	107640	107640	107640	107640	107640	107640	107640
Annual Heating Degree Days	3851.8	3851.8	3851.8	3851.8	3851.8	3851.8	3851.8	3851.8
Annual Cooling Degree Days	87.7	87.7	87.7	87.7	87.7	87.7	87.7	87.7
kWh before real-time monitor	36125	34673	20009	18600	13230	12298	19160	13464
Change in kWh due to real-time monitor	-828.5	-653.3	-3348.7	-3112.7	-668.4	-621.3	-621.2	-774.4
Percentage Response (%)	-2.29	-1.88	-16.74	-16.74	-5.05	-5.05	-3.24	-5.75

Table 4 (continued): Percentage Impact of Real-Time Monitor: By Heating-Water Heating-Air Conditioning Configurations

By Region in Ontario

Electric Heating: (Percentage of house heated with electricity: DF)	100	100	0	0	0	0	0<DF<100	0
Electric Water Heating:	Yes	Yes	Yes	Yes	No	No	---	---
Air Conditioning: (Percentage of house cooled: DA)	100	0	100	0	100	0	0<DA<100	$0 \leq DA \leq 100$

Peterborough

Square Footage	1998	1998	1998	1998	1998	1998	1998	1998
Number of Residents	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64
Income	63096	63096	63096	63096	63096	63096	63096	63096
Annual Heating Degree Days	4400.5	4400.5	4400.5	4400.5	4400.5	4400.5	4400.5	4400.5
Annual Cooling Degree Days	93.6	93.6	93.6	93.6	93.6	93.6	93.6	93.6
kWh before real-time monitor	29724	28666	15257	14240	10606	9899	18336	12386
Change in kWh due to real-time monitor	-220.5	-112.3	-2553.4	-2383.1	-535.8	-500.0	-1541.7	-1423.8
Percentage Response (%)	-0.74	-0.39	-16.74	-16.74	-5.05	-5.05	-8.41	-11.50

Table 4 (continued): Percentage Impact of Real-Time Monitor: By Heating-Water Heating-Air Conditioning Configurations

By Region in Ontario

Electric Heating: (Percentage of house heated with electricity: DF)	100	100	0	0	0	0	0<DF<100	0
Electric Water Heating:	Yes	Yes	Yes	Yes	No	No	---	---
Air Conditioning: (Percentage of house cooled: DA)	100	0	100	0	100	0	0<DA<100	$0 \leq DA \leq 100$

Timmins

Square Footage	1675	1675	1675	1675	1675	1675	1675	1675
Number of Residents	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.97
Income	73368	73368	73368	73368	73368	73368	73368	73368
Annual Heating Degree Days	5765.9	5765.9	5765.9	5765.9	5765.9	5765.9	5765.9	5765.9
Annual Cooling Degree Days	45.3	45.3	45.3	45.3	45.3	45.3	45.3	45.3
kWh before real-time monitor	30389	29990	15304	14926	10506	10246	15146	10001
Change in kWh due to real-time monitor	547.8	-575.1	-2561.2	-2497.8	-530.8	-517.6	-668.5	-771.7
Percentage Response (%)	1.80	1.92	-16.74	-16.74	-5.05	-5.05	-4.41	-7.02

Customers' Attitudes and Perceptions Regarding the Real Time Monitor:

Having quantified the conservation impact of the real-time monitor, it is now worthwhile to compare this with the participants' attitudes toward the real-time monitor and their perceptions of their behavior.

Tables 5 to 7 indicate a very high level of satisfaction with the real-time monitor. According to questionnaire statistics, 60.5% of the participants felt the monitor made a difference in their homes. The majority of the participants, 65.1%, reported that they planned to continue using the monitor after the pilot was complete. When asked how useful they found the monitor in helping them conserve energy, 63% of the participants ranked the monitor 3 or greater on a scale of 0 to 5. If we decompose the sample into houses heated entirely by electricity versus all other houses, participants in electrically heated houses see the monitor as a little less useful (59.9% with a rank of 3 or greater) than those in non-electricity heated houses (64.5% with a rank of 3 or greater). This lends support to the distinctly lower responsiveness for electric heated houses.

Table 8 provides an indication of how often participants consulted their real-time monitor. Our findings indicated that 38.9% of the participants consulted the monitor either daily or multiple times per day. Nevertheless, this does mean that over 60% of the participants consulted the real-time monitor less than on a daily basis. Thus, while the potential of feedback is always available, it does not mean that everyone is making use of this information.

Table 5: Overall Evaluation

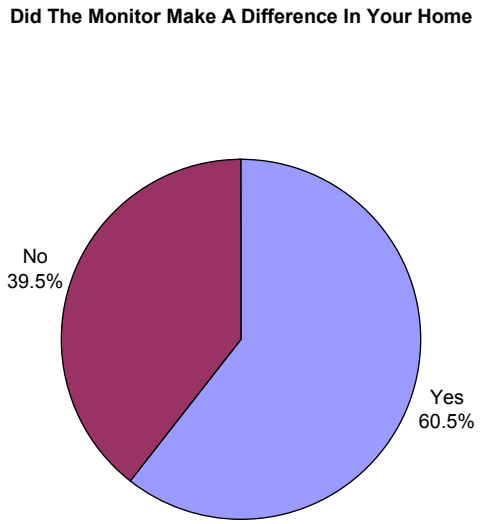


Table 6: Permanence of Usage

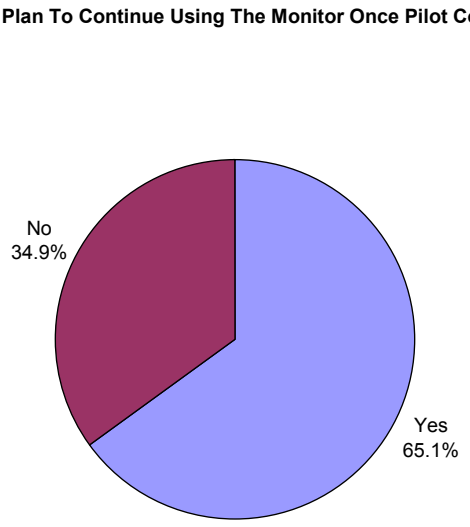
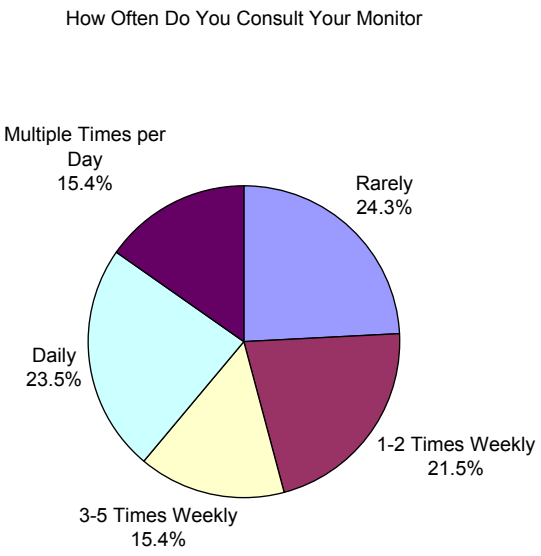


Table 7: Usefulness of Monitor (0 - Not Useful; 5 - Very Useful)

Percentage (%)

Usefulness	Heated Entirely by Electricity	Other Houses	Total Sample
0	3.5	5.6	4.9
1	16.5	12.2	13.6
2	20.0	17.8	18.5
3	23.5	25.0	24.5
4	18.8	22.8	21.5
5	17.6	16.7	17.0

Table 8: Consultation of Monitor



The questionnaires also analyzed participants' perception of their savings. Interestingly, when the questionnaire statistics were compared with the actual measured savings there is a mild understatement of participants' expected savings as illustrated in Table 9. While the empirical results suggested an overall reduction of 6.5%, 52.1% of the sample saw their potential savings to be between 0% and 5%. Only 17.5% of the sample saw their savings greater than or equal to 10%. Overall, it would seem that in aggregate participants' perceptions of their savings are not that far from their actual savings. It appears as though the perceptions of the participants are very accurate.

Again, lending further support to reduced conservation in electric heating households, Table 9 shows that 57.1% of electrically heated houses saw their savings in the range of 0% to 5%; whereas, for non-electricity heated houses, 49.7% saw their savings in the 0% to 5% range.

Table 9: Households' Perceived Expected Savings

Percentage Saved	Percentage of Households (%) Heated Entirely by Electricity	Other Houses	Total Sample
0-5	57.1	49.7	52.1
5-10	28.6	31.2	30.3
10-15	7.8	12.7	11.1
15-20	6.5	4.5	5.1
> 20	0.0	1.9	1.3

Conclusions:

1. A primary finding of the pilot study is that real-time feedback of energy consumption is effective in promoting conservation. The results are statistically significant and support the hypothesis that real-time monitors encourage conservation.

- This is based on a very comprehensive study conducted over a long time period. In comparison to previous pilots and demonstration projects regarding direct feedback, the sample size for this pilot study is very large comprising 5015 billing observations that were used in the analysis. Pilot participants and control customers were followed over a 2.5 year period.
- The experimental design consisted of a stratified random sample, spread across a wide geography, diversity of weather regions, a wide variation in the heating, cooling, water heating and appliance configurations, and a large variety of household income and demographic characteristics.

2. Overall, the average reduction in energy consumption across the whole sample was 6.5%.

- Within this sample, non-electric heating households are showing a significant conservation impact or reduction in energy consumption of 8.2%. Within the non-electric heating group, the range in reduction is from 5.05% (for a non-electric water heating house) to 16.74% (for an electric water heating house).
- We also observed that electric heating households are not responding in a significant way to real-time feedback. Separating out the feedback from the

electric heating load and the rest of the load would be required to encourage conservation in this sector.

3. The results indicate a persistent response over the study time period and this finding is important for larger deployment of such a device. No reduction in conservation response was detected through the duration of the pilot. Furthermore, the qualitative feedback from participants was positive: they were generally very pleased with the performance and usefulness of the real-time monitor in helping them reduce energy consumption and manage their costs.

4. An overall average reduction of between 7% and 10% is feasible if the real time monitor is used in conjunction with other conservation and/or price measures.

- The overall reduction of 6.5% observed in the study corresponds only to the impacts of real-time feedback. In this pilot no other price and/or conservation incentives accompanied the real-time monitor. Thus, these results are interpreted as the bare minimum impacts.
- If the real-time monitoring is used in conjunction with other price and/or conservation measures, the conservation impact will be larger.

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Green Energy Coalition (GEC) INTERROGATORY #2 List 1

Interrogatory

Issues 1.2, 3.11, 4.9 (Line Losses & OEB Directives) Ex. A-17-1, page 3

The Board at para. 4.3.10 of its 2006 Rates Decision directed that HONI file a work plan for implementing the Kinectrics proposals that were not undertaken in 2006 or justify otherwise. In Exhibit A-15-3 attachment A, pages 28-29 Kinectrics updates their recommendations and proposes spending and further studies. At A-15-3, page 12 HONI indicates that no additional line loss reduction efforts are currently planned beyond those routinely pursued and at D1-3-5, page 37, table 10 no amounts appear for CDM capital spending in 2008. Please clarify which Kinectrics recommended initiatives (including work programs and studies) HONI is undertaking in 2008 and to what extent (or has completed in prior years) and which it is deferring or not pursuing in whole or part, if any.

Response

Please see the response provided in Exhibit H, Tab 1, Schedule 97.

Hydro One has addressed all cost-effective line-loss reduction suggestions recommended by the Kinectrics' update study report.

Green Energy Coalition (GEC) INTERROGATORY #3 List 1

Interrogatory

Issue 3.1 (O&M Expense for DG studies) Exs. C1-2-3, page 2, Table 1 and E3-1-1, pages 9-10

HONI forecasts continued high but declining expenditures on Development OM&A for Data Collection, Engineering and Technical Studies in part due to DG connection studies (with corresponding reducing revenue – E3-1-1,page 3, table 2).

a) Please explain why HONI forecasts a decline from 2007 to 2008 given its present inability to meet regulatory requirements for connection assessments (as evidenced by its Nov. 30th request to the OEB for relief from DSC provisions in that regard) and given the expected additional work that will result from the forthcoming OPA Clean Energy Standard Offer Program?

b) Do the expected 225 DG studies (E3-1-1, page 10, table 11) in 2008 include CESOP triggered studies?

Response

a. As shown in Table 1 of Exhibit C1, Tab 2, Schedule 3 of the February 20, 2008 update to the pre-filed evidence, the total expenditures on Data Collection, Engineering and Technical Studies are constant, not declining, from 2007 to 2008.

b. Yes.

Green Energy Coalition (GEC) INTERROGATORY #4 List 1

Interrogatory

Issue 5.3 (accounting treatment of revenue and expenses for OPA funded CDM)

Please provide a summary of spending and revenue by program for all OPA funded, HONI delivered, CDM programs in 2006, 2007 and expected for 2008 and indicate if these amounts have been eliminated from utility revenues and expenses or how they are being accounted for.

Response

There were no OPA funded, HONI delivered CDM programs in 2006. In 2007, HONI delivered four OPA programs as detailed in the interrogatory response at Exhibit H, Tab 2, Schedule 7. The 2007 OPA programs had $7.6 million in expenditures with matching revenues. The 2007 OPA program schedules have been extended into 2008 and a further $2.1 million of expenditures is anticipated under these schedules in 2008.

HONI's anticipated funding for the 2008 OPA Core Program Schedules for which information is available is approximately $11.3M, as shown in the interrogatory response at Exhibit H, Tab 2, Schedule 8.

As per the Ontario Energy Board's "Guidelines for Electricity Distributor Conservation and Demand Management" issued March 28, 2008, the costs and revenues of OPA-funded programs are not part of the regulated Distribution Business and are to be kept separate from the distributor's revenue requirement.

Energy Cost Management Inc *(ECMI) INTERROGATORY #1 List 1*

Interrogatory

Does the statement "Any new customer satisfying the criteria for ST classification, will be classified as an ST account " include a delivery point to an LDC ?

Feb 20 2008 ref
Exhibit G2
Tab 94
Schedule 1
Page 1 of 8
Page 3476 of February 2008 pdf

Response

Yes

Energy Cost Management Inc *(ECMI) INTERROGATORY #2 List 1*

Interrogatory

a) If the answer to ECMI interrogatory #1 is no, what does it mean, and
b) what would happen to a new LDC delivery point?

Response

Please see response to interrogatory Exhibit H, Tab 4, Schedule 1.

Energy Cost Management Inc *(ECMI) INTERROGATORY #3 List 1*

Interrogatory

How many of the 358 embedded LDC delivery points as referenced in Table 9 are delivery points as Wholesale Market Participant delivery points?

Feb 2008 ref
Ref G1
Tab 2
Schedule 3
9 of 9
Page 1556 of Feb 2008 pdf

Response

289 delivery points out of 358 embedded LDC delivery points are Wholesale Market Participant.

Energy Cost Management Inc *(ECMI) INTERROGATORY #4 List 1*

Interrogatory

a) How many of the 358 embedded LDC delivery points as referenced in Table 9 are delivery points which are Wholesale Market Participant delivery points through ISO approved delivery point (using current standards for such metering) have resulted in under billing by the applicant due to metering errors?

b) Please provide the amount in dollars, and

c) the number of delivery point locations involved in such incidences.

Response

a) None

b) None

c) None

Energy Cost Management Inc *(ECMI) INTERROGATORY #5 List 1*

Interrogatory

a) How many of the 358 embedded LDC delivery points as referenced in Table 9 are delivery points which are Wholesale Market Participant delivery points through ISO approved delivery point (using current standards for such metering) have been involved in theft of power by the LDC resulting in losses by the applicant?

b) Please provide the amount in dollars and

c) the number of delivery point locations involved in such incidences

Response

a) None

b) None

c) None

Energy Cost Management Inc *(ECMI) INTERROGATORY #6 List 1*

Interrogatory

a) How many of the 358 embedded LDC delivery points as referenced in Table 9 are delivery points which are Wholesale Market Participant delivery points through ISO approved delivery point (using current standards for such metering) have resulted in a requirement for the applicant to provide surety or similar guarantees to the ISO?

b) Please provide the amount in dollars and

c) the number of delivery point locations involved in such incidences

Response

a) None

b) None

c) None

Energy Cost Management Inc *(ECMI) INTERROGATORY #7 List 1*

Interrogatory

a) How many of the 358 embedded LDC delivery points as referenced in Table 9 are delivery points which are Wholesale Market Participant delivery points through ISO approved delivery point (using current standards for such metering) have been abandoned by the LDC and resulted in a loss in revenue to the applicant (excluding those which were delivering power to LDC's acquired by the applicant or point which where such action was at the request of the applicant)?

b) Please provide the amount in dollars, and

c) the number of delivery point locations involved in such incidences

Response

a) None

b) None

c) None

Energy Cost Management Inc *(ECMI) INTERROGATORY #8 List 1*

Interrogatory

What is the basis of the 500kW demand?

Feb 2008 ref
Ref G1
Tab 2
Schedule 3
8 of 9
Page 1555 of Feb 2008 pdf

Response

Hydro One Networks' policy is that the maximum padmount transformer size it supplies is 500 kVA, and the maximum overhead (polemount) transformer size it supplies is 501 kVA. Customers would supply and own transformers larger than 500 kVA.

500 kVA is also the threshold used in determining at what voltage customers should be connected. At 500 kVA or higher, a sub-transmission voltage connection is required, e.g. 13.8 kV to 44 kV.

Energy Cost Management Inc *(ECMI) INTERROGATORY #9 List 1*

Interrogatory

The revised revenue requirement from the current rates in Table 1 for the proposed Sub Transmission class is $64.2m. If the ST class were split into LDC and retail over500kWseparate classes please provide the values for the expanded table.

Table 9
Exhibit G1
Tab 2
Schedule 3
Page 9 of 9
Page 1572 of Feb 2008 pdf

Response

We understand the reference to be to Table 1 on page 2 of Exhibit G1, Tab 3, Schedule 1.

The $64.2 million estimated 2008 Revenues at adjusted current rates from the ST class shown in Exhibit G1, Tab 3, Schedule 1, page 2, Table 1, includes $23.5 million from only LDCs and $40.7 million from the rest of the ST customers, that is, Directs, Large Users, and other end-use customers being mapped into the new ST class.

Energy Cost Management Inc *(ECMI) INTERROGATORY #10 List 1*

Interrogatory

The revised revenue requirement from proposed rates for the proposed Sub Transmission class is $27.4m. If the ST class were split into LDC and retail over 500kW separate classes please provide the values for the expanded table.

Table 9
Exhibit G1
Tab 2
Schedule 3
Page 9 of 9
Page 1572 of Feb 2008 pdf

Response

We understand the reference to be to Table 1 on page 2 of Exhibit G1, Tab 3, Schedule 1.

Hydro One can provide an estimate of how much of the $27.4 million revenue requirement allocated to the ST class in Table 1 would be collected from LDCs based on the results of the OEB Cost Allocation Model included in the pre-filed evidence. The amount is $18 million and assumes that the ST class revenue to cost ratio is equal to 1.

A substantial amount of effort, and information that is not readily available, would be required to split the ST class and do the cost allocation separately for LDCs and other ST customers. The effort would include making modifications to the OEB cost allocation model, completing a detailed analysis of the assets specifically used to supply LDC customers versus other ST customers, and developing a wide range of customer load data for LDCs and other ST customers separately.

The new ST class is composed mostly of Embedded LDC customers, which account for approximately 80% of the ST class consumption. Therefore, creating a customer class exclusively of Embedded LDCs would not produce significantly different results than for the ST class proposed.

Wescast INTERROGATORY #1 List 1

Interrogatory

Issue Number: 1.7

Issue: Are the proposed Distribution Loss Factors appropriate?

Ref: Gl/Tab lO/Sch lIPage 5

a) In situations where the customer is supplied at two meter points on the same feeder, on which the customer is the only customer supplied by the feeder, would Hydro One accept an engineering study for the purpose of assigning a specific loss factor for the customer?

b) If the engineering study is completed after the 2008 rates come into effect, will Hydro One repay the difference in amounts collected between the calculated losses and the current 3.4% rate?

Response

a) No. Engineering studies for assets that supply one customer with more than one meter point on the same feeder do not produce consistently accurate results due to differences in power flows over time in comparison with the assumptions needed complete the studies. Application of such an approach would also result in the inconsistent treatment of losses among similar customers.

b) No. Consistent with its policy, Hydro One has not been making retroactive adjustments in the application of site specific loss factors for settlement.

Wescast INTERROGATORY #2 List 1

Interrogatory

Issue Number: 6.1

Issue: Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts (Regnlatory Assets) appropriate?

Ref: FliTab lISch l/Page13/Table 8

Preamble: Since Nov 1,2007, Wescast Industries and other companies connected to the Hydro One distribution system have been placed at a cost disadvantage compared to transmission connected competitors with respect to Transmission Connection charges.

a) Please identify the amount in the variance account that has accrued from the Nov 1, 2007 change in RTSRs.
b) Please identify how these over-charges will be repaid to customers.

Response

a) The Retail Transmission Service Rates (RTSRs) charged to embedded LDC's and embedded Direct customers have not changed. The impact of the decreased Uniform Transmission rates effective November 1, 2007 is included in the appropriate RSVA accounts. For the period November 1 2007 to April 30, 2008, the estimated impact of the new Uniform Transmission rates is $11.4M (inclusive of interest).

b) Any variance related to RTSRs is being recorded in the appropriate RSVA accounts. Hydro One is proposing Regulatory Rider # 3, as described in Exhibit G1, Tab 5, Schedule 1, and proposes to refund Rider # 3 over 4 years, consistent with the period of collection used for Riders # 1 and # 2 approved by the OEB. The allocation amongst customer classes of all variance accounts included in Regulatory Rider # 3 is explained in the same exhibit.

Power Workers' Union (PWU) INTERROGATORY #1 List 1

Interrogatory

Issue: 1.6

Issue: Is service quality on the OEB specified performance indicators acceptable?

Exh.A/T15/S1/P.7 (Table 2: Service Reliability Indicators)

(a) Please explain the reason why the OEB's SAIFI target for the years 2005, 2006, 2007 and 2008 (≤ 3.1) is lower (less strict) than the OEB's SAIFI target for 2004 (≤ 3.0)?

(b) Please expand Table 2 to include data for 2002 and 2003.

Response

a) Please refer to the interrogatory response in Exhibit H, Tab 1 Schedule 53.

b) Table 2 Service Reliability Indicators

Performance Measure	2002 OEB Tgt	2002 Act	2003 OEB Tgt	2003 Act	2004 OEB Tgt	2004 Act	2005 OEB Tgt	2005 Act	2006 OEB Tgt	2006 Act
SAIFI *Frequency of Interruptions* (#of interruptions per customer)	**≤ 3.2**	**2.9**	**≤ 3.0**	**2.9**	**≤ 3.0**	**3.1**	**≤ 3.1**	**2.9**	**≤ 3.1**	**2.9**
SAIFI including *Force Majeure*		**3.2***		**3.5****		**3.2*****		**3.9†**		**5.2††**
SAIDI *Duration of Interruptions* (hrs of interruption per customer)	**≤ 10.1**	**9.4**	**≤ 9.4**	**8.0**	**≤ 9.4**	**6.5**	**≤ 9.4**	**8.0**	**≤8.0**	**7.1**
SAIDI including *Force Majeure*		**12.5***		**15.1****		**6.9*****		**14.5†**		**28.4††**
CAIDI *Average Interruption Time* (#of hrs per interruption)	**≤ 3.1**	**3.2**	**≤ 3.1**	**2.8**	**≤ 3.1**	**2.1**	**≤ 3.0**	**2.8**	**≤ 2.6**	**2.4**
CAIDI including *Force Majeure*		**3.9***		**4.3****		**2.2*****		**3.7†**		**5.5††**

* Please see Attachment 1 for details on "2002 Force Majeure Events"

** Please see Attachment 1 for details on "2003 Force Majeure Events"
*** See Exhibit A, Tab 15, Schedule 1 for details on "2004 Force Majeure Events"
† See Exhibit A, Tab 15, Schedule 1 for details on "2005 Force Majeure Events"
†† See Exhibit A, Tab 15, Schedule 1 for details on "2006 Force Majeure Events

ATTACHMENT 1

Information below is extracted from Exhibit A, Tab 15, Schedule 1 in the 2006 Rates Application under Proceeding EB-2005-0378.

1.0 2002 Force Majeure Events

Hydro One Distribution considers the storms of January 31st to February 1st and March 9 to12th, 2002 as "force majeure" events. The 2 storms interrupted 11% and 21% of our customers respectively. This type of damage is beyond what is typically expected from historic business practice. The January 31st to February 1st, 2002 storm caused massive damage in Ontario from Essex to Vankleek Hill along the north shores of Lake Erie and Lake Ontario. Environment Canada reported snow, freezing rain and winds up to 100 km/hr. The storm snapped trees and poles and caused major structural damage. It closed roads and brought normal activities to a stand still, especially in Southwestern Ontario.

The second storm March 9th to 12th, 2002 had such extensive damage that repairs continued into the following week. Icy winds tore through Southern Ontario for more than 24 hours, uprooting trees, knocking down power lines and damaging property by hurling roof shingles and blowing large beams 30 meters across a highway. Debris and trees littered the roads and highways making it difficult to travel. In some cases roads were closed to traffic due to the damage which inhibited power restoration efforts.

Removing the effect of the 2 storm results in annual SAIDI of 9.4 hours, annual SAIFI of 2.9 interruptions and annual CAIDI of 3.2 hours.

1.1 2003 Force Majeure Events

In 2003 there were four storms that met the force majeure criteria. The storms occurred on April 4th, August 21st, November 12th and November 28th. Each of those days, respectively they interrupted the following percentages of customers: 16%, 12%, 27% and 16%.

On April 4th, 2003, southern Ontario, from Essex to Vankleek Hill, was hit with freezing rain, and ice pellets, heavy ice accumulation, and gusting winds from 40 to 60 km/hr. Over the course of the outages caused by this storm over 180,000 Hydro One customers experienced outages in Hydro One territory.

On August 21st, thunder storms and high winds adversely affected 18 of our Operation Centers from Georgian Bay east to the Quebec border. The storms interrupted power to 123,000 our customers.

A winter windstorm started on November 12th. High winds from 60 km/h gusting to 110 km/h and snow squalls caused power interruptions to about 130,000 Hydro One

customers across Ontario from Sudbury to Lakes Erie and Ontario.

Another winter storm hit southern, central and eastern Ontario on November 28th. This time high winds gusting up to 80 km/h and heavy, moist snow caused power interruptions to about 180,000 Hydro One customers.

Removing the effect of the 4 storms result in annual SAIDI of 8.0 hours, annual SAIFI of 2.9 interruptions and annual CAIDI of 2.8 hours.

Power Workers' Union (PWU) INTERROGATORY #2 List 1

Interrogatory

Issue: 1.6

Issue: Is service quality on the OEB specified performance indicators acceptable?

Ref (a): Exh.A/T3/S1/P 18 – Figure 4, P.19 – Figure 5
Ref (b): Exhibit C1/Tab 2/P.30/ Table 9

Preamble:

Ref (a) indicates that tree contacts accounted for 57% of total SAIDI and 28% SAIFI for the period 2003-2006.

Ref (b) indicates that vegetation management accounted for $88.9m, $86.4m, and $89.1m in 2004, 2005, and 2006 respectively.

Questions:

(a) Please explain why the budget allocated to vegetation management decreased in 2005 by about 3% from the amount in 2004.

(b) Can Hydro One confirm that the high contribution of tree contacts to SAIDI and SAIFI in Ref (a) is partly due to the low levels of spending on vegetation management for the period 2004-2006? Please explain.

Response

a. The 2004 and 2005 figures are actual values, not budget amounts. The budget allocated to vegetation management did not decrease in 2005 from the amounts in 2004. Please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 63 for additional details on vegetation management accomplishments.

b. Typically there is a lag between increased or reduced spending on vegetation management and reliability performance. For details on the Vegetation Management Program's impact on reliability, please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 49.

Power Workers' Union (PWU) INTERROGATORY #3 List 1

Interrogatory

Issue 4.3

Issue: Are the 2008 sustaining capital expenditures proposed for Asset Replacement appropriate?

Ref (a): Exhibit A/T15/S 2/ Attachment A, Hydro One Distribution Benchmarking Study and Exhibit A/T 14/S 5 – Tree Trimming

Preamble:

Ref (a) states:
"…Hydro One has by far the longest cycle time between consecutive trimming of each tree. It would be worth investigating to see whether that has led to greater difficulty in performing the trimming when the time comes for each tree or circuit. It is also conceivable that this long cycle leads to more "hot-spot" trimming than usual, which is typically more expensive than routine cycle trimming. Previous studies executed by PA Consulting have indicated that the optimum tree trimming cycle length is nearer to 5-6 years than to the 11 currently in practice at Hydro One."

Questions:

(a) Please provide Hydro One's understanding of the above statement, specifically whether shortening the tree trimming cycle length from the current 11 years to 5-6 years would be less expensive and/ or improve reliability.
(b) Does Hydro One plan to shorten its current tree trimming cycle length? Please explain.

Response

a. Hydro One's understanding of the statement referenced is that once a shorter cycle is fully implemented, the unit cost for tree trimming will be less than the current cost. This reduction is driven by the fact that a shorter cycle would result in crews dealing with less vegetation growth.

For details on the Vegetation Management Program's impact on reliability, please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 49.

b. Yes, Hydro One Distribution is planning for an 8 year clearing cycle in 2008 as discussed in the interrogatory response in Exhibit H, Tab 1, Schedule 50.

Power Workers' Union (PWU) INTERROGATORY #4 List 1

Interrogatory

Issue 4.3

Issue: Are the 2008 sustaining capital expenditures proposed for Asset Replacement appropriate?

Ref (a): Exhibit D1 Tab 2 Schedule 1 page 7
Ref (b): Exhibit D1 Tab 3 Schedule 2 – Wood Structure Replacement

Preamble:

In Ref (a), "Very Poor" and "Poor" condition assets are defined as high risk and requiring replacement, refurbishment or other remedial action within the next 5 years to correct significant deterioration.

In Ref (b), On Page 19, it is indicated that about 4% of Hydro One's 1.65m **poles** have been found to be sub-standard, i.e., in "poor" or "very Poor" state. This amounts to 66,000 poles.

On Page 20, it is stated that Hydro One replaced 5,200 poles in 2006 and 6,852 poles in 2007 and plans to replace 7, 000 poles in 2008.

Questions:

(a) What proportion of the 4% (66,000) of the poles require replacement in the next 5 years and what proportion is planned for refurbishment or other remedial action?

(b) If the 66,000 poles cited above require replacement over the next 5 years, and given the historic data for 2006 and 2007 cited above, please explain how Hydro One plans to achieve the target of replacing 66,000 poles in "poor" and "very Poor" condition in the next 5 years at the current rate of pole replacement?

(c) Please explain the slight decrease from $ 40.1m in the 2007 to $39.8m in the 2008 Test year in the spending level for pole replacement given Hydro One's plan of increasing the number of poles replaced from 6,852 in 2007 to 7,000 in 2008?

Response

a. Those poles that are found to be in very poor condition will be replaced under Trouble Call and the poles found to be in poor condition as part of the pole assessment program will be replaced within 5 years.

b. Please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 18.

c. The slight reduction in planned 2008 expenditures from 2007 is driven by lower unit costs in 2008. Through the Wood Structure Replacement Program, Hydro One replaces a wide variety of poles in terms of pole class, height, footing type (e.g. in earth, in rock) and location. In any given year, the mixture of replacements can swing from lower cost poles to higher cost depending on the quantities and types of poles that have been identified for replacement. For example, a smaller pole supporting a rural feeder is less costly to replace than a larger pole supporting a sub-transmission feeder. In 2007, the approximate ratio of rural poles to sub-transmission poles was 2:1 where in 2008 the number of rural poles compared to subtransmisssion poles is expected to increase. The greater proportion of rural pole replacements in 2008 drive the lower overall unit cost for the program and thus the slight reduction in overall spending.

Energy Probe Research Foundation (EP) INTERROGATORY #1 List 1

Interrogatory

Ref: Exh. D1/T 2/S 1, p. 16 of 20
Issue 3.2: Is the 2008 vegetation management budget appropriate?

Page 16 of 20 of the schedule discusses vegetation management and concludes that an increased percentage of rights of way are in the *poor* or *very poor* categories. The increase is attributed to underachievement of 2005 and 2006 target workloads. The 2006 underachievement is attributed to the need to redeploy staff to deal with storm damage.

Please provide details of the unusually high number of storms in 2006 and the amount of damage caused by these storms compared with a normal year.

Response

The table below contains details on the amount of damage for storm-related force majeure events in 2006 as compared to 2004 and 2005. The table quantifies the damage both in terms of reliability (i.e. SAIDI and SAIFI) and expenditures related to storm restoration.

Year	2004	2005	2006
Number of Force Majeure Storms	1	4	8
SAIFI Contribution (# of interruptions)	0.1	1.0	2.2
SAIDI Contribution (# of hours)	0.4	6.4	21.2
Storm Damage Capital Expenditure ($M)	$14.0	$26.3	$62.0
Storm Damage O&M Expenditure ($M)	$0.9	$8.1	$21.0

Based on its experience, Hydro One considers 1 to 2 force majeure storms to be a below average storm year, 3 to 5 storms to be an average year, and more than 5 storms to be an above average storm year. For a detailed list of all force majeure events see Exhibit A, Tab 15, Schedule 1, starting on page 8.

Energy Probe Research Foundation (EP) INTERROGATORY #2 List 1

Interrogatory

Ref: Exh. D1/T 2/S 1, p. 16 of 20
Issue 3.2: Is the 2008 vegetation management budget appropriate?

The underachievement of 2005 target workload is attributed to a labour disruption. Energy Probe is under the impression that the 2005 labour disruption involved management and professional staff not the trades staff that carry out vegetation management programs.

If this is so, please explain how this labour disruption adversely affected achievement of right of way vegetation management.

Response

Please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 63.

Energy Probe Research Foundation (EP) INTERROGATORY #3 List 1

Interrogatory

Ref: Exh. C2/T 3/S 1, p. 1 of 3
Issue 3.6: Are the 2008 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate?

The table on Page 1 of 3 shows representative earnings for a Regional Maintainer Lines (PWU represented). Overtime is approximately 47% of annual base salary. Please explain the following:

a) What are the base working hours included in base salary?

b) How many overtime hours are represented by the overtime pay?

c) What percentage of employees in this group work more overtime hours than those represented by the overtime pay in this table?

d) Does Hydro One have any policies and/or practices in place to monitor how much overtime individual employees work in a year? If so, please describe them.

e) Does Hydro One have any policies and/or practices in place to define what it would consider to be excessive overtime and to identify individual employees working excessive overtime? If so please describe them.

Response

a) The base hours of work for the Regional Maintainer Lines classification are 8 hours per day, 40 hours per week.

b) The number of overtime hours were as follows:

2004 – 416
2005 – 449
2006 – 500
2007 – 500
2008 - 500

c) For each of the years 2004, 2005 and 2006, 50% of the staff worked more overtime than the average. This trend is expected to continue for 2007 and 2008.

d) Hydro One's employees in the Regional Maintainer Lines classification are governed by a number of items with respect to overtime hours. The Ontario Employment Standards Act (ESA) restricts hours of work to 8 in a day and 48 in a week except where exempted by permit. Hydro One has an 'Excess Weekly Hours of Work Permit' that allows employees to work up to 60 hours in a week. In addition there are provisions in the Hydro One - Power Workers' Union collective agreement that provide for rest periods for employees after they have worked extended overtime. The Hydro One – Power Workers' Union collective agreement also includes provisions to equitably distribute overtime.

e) As indicated in the above answer, there are provisions in the Hydro One – Power Workers' collective agreement to provide for rest periods and equitably distribute overtime.

Energy Probe Research Foundation (EP) INTERROGATORY #4 List 1

Interrogatory

Ref: Exh. D2/T 2/S 3 (Ref#: S3)
Issue 4.2: Are the amounts proposed for 2008 Capital Expenditures appropriate?

a) This schedule discusses Distribution Station Refurbishment, listing those stations scheduled of refurbishment in the test year. Were any of these stations previously owned by municipal utilities acquired by Hydro One since 1998? If so, please state which ones.

b) Were any of the stations refurbished by Hydro One over the past 10 years previously owned by municipal utilities acquired by Hydro One since 1998? If so, please provide details.

Response

a) The following stations listed in the schedule for Distribution Station Refurbishment were previously owned by municipal utilities and acquired by Hydro One: Brockville Parkdale DS, Durham Elgin DS, Lindsay Eglington DS.

b) The follow stations were previously owned by municipal utilities acquired by Hydro One and were refurbished over the last 10 years.

Number	Station Name	Year Refurbished
1	Alexandria Margaret	2003
2	Thorold Cleveland	2002
3	Marmora Reginald	2002
4	Dryden Government	2003
5	Feneon Falls Elliott	2003
6	Thessalon Peachy	2003
7	Thessalon Government	2003
8	Arnprior Reid	2002
9	Arnprior Elgin	2002
10	Lindsay Eglington	2004
11	Stirling Baker	2002
12	West Lorne	2004
13	Deep River	2004
14	Alexandria East Boundary	2004
15	Bobcaygen Boyd	2006
16	Bolton King	2005
17	Owen Sound 2nd Ave.	2007
18	Brockville Schofield	2006
19	Brockville Cedar	2007
22	Trenton McCauley	2007
23	Trenton Dundas	2007
24	Elliot Lake Mississaugi	2003
25	Port Robinson	2005
26	Bobcaygen Duke	2005
27	Napanee Mills	2006
28	New Liskard Haliburton	2003
29	Lindsay Durham	2007
30	Perth Sunset	2006
31	Campbellford Alma	2007
32	Milverton	2006
33	Winchester Dufferin	2006
34	Madoc Madawaska	2006
35	Alexander West Boundary	2005

1

Energy Probe Research Foundation (EP) INTERROGATORY #5 List 1

Interrogatory

Ref: Exh. D2/T 2/S 3 (Ref#: S16)
Issue 4.2: Are the amounts proposed for 2008 Capital Expenditures appropriate?

This schedule discusses the need to rebuild a 2.4 kV feeder in the Town of Thessalon acquired in the purchase of the local municipal utility.

a) How much was spent on Phase 1 of this project?

b) Please provide details of the acquisition of the municipal utility specifically:

i) The cost of the acquisition

ii) Any studies that Hydro One conducted on the value of the utility

iii) Any reports that Hydro One had on the condition of the utility's assets

Response

a) About $0.7 million has been spent on phase 1 of this project.

b)

i. the cost of the acquisition was approximately $560,000 in 2001
ii. please see attached a copy of the Thessalon Summary Due Diligence Report (Attachment A)
iii. please see attached a copy of the Thessalon Asset Condition Assessment (Attachment B)

Thessalon HEC
Due Diligence Summary Report

DISTRIBUTION:

J. Boyer
G. Carleton
C. Cartwright
E. Davison
M. Della Rosa
W. Manley
G. O'Neill
A. Pantusa
S. Struthers
W. Taggert
Y. Tsimberg

_____
Date

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1.0 Background & Observations

- This report summarizes key issues and comments as a result of M&A due diligence efforts on **Thessalon HEC.**
- **Thessalon** is a utility with **no full time staff** and **729** customers.
- Due diligence issues in this report have been organized based on a checklist of priorities developed and updated by M&A.
- The customers of this utility would be easy to integrate into the Hydro One system.
- The due diligence efforts did not discover any issues that would materially impact the deal, assuming the purchase prices is adjusted in accordance with recommendations and accept for potential liabilities in section 6.0.

2.0 Executive Summary

Section	Observation	Impact	Suggested Course of Action	Comments
Operations *Walter Kloostra*	The Utility has been requested to terminate agreements with Harris for customer system maintenance and with Northern Meter Services for meter testing.		The customer information will be incorporated into H1's CCS system. Meter testing will be done by H1 inhouse.	
	46 of the inventory transformers have no value to H1.		Exclude from the purchase.	
	The utility has a joint use agreement with Regional Cable Systems		Joint use agreements will not be assigned to H1. H1 has master agreements in place with the cable and telephone companies.	
	The HEC is currently a member of Enerconnect.		Request the HEC to terminate this membership prior to closing.	
Environmental *Walter Kloostra*	Thessalon does not have an in-service transformer PCB test program.		The transformers will be incorporated into H1's PCB testing program.	Integration Issue
	The two transformer station sites have not yet been tested.		The test showed no sites contamination.	
Customer Service/Metering *Steve Vance*	The Utility does not have customer telephone numbers in their system.	If Utility does not complete this action, it may cost H1 about $3000 to complete.	The Utility has been requested to incorporate this information prior to closing.	
	The meter re-verification program for 2000 is complete. About 80 meters still need to be verified for the 2001 program.		The HEC has been requested to complete this program prior to closing. All meters will be incorporated into H1's meter re-verification program thereafter	Integration Issue
	One metering installation uses voltage stepped down from primary and CT's at secondary – this is non compliant and must be changed.	If the Utility does not complete this action, the approximate cost to H1 is $3,000.	The Utility has been requested to correct this metering setup.	
Financial *Doug LaFramboise*	Purchase price is currently based upon Dec 1999 book value. Book value appears to have declined since then.	$29K ($39K-$9K)	The purchase price should be adjusted to account for any reduction in book value since Dec 1999	
	Qualifying transition cost has no value to H1	$32.4K	Decrease purchase price accordingly	
	Water and electricity assets are currently combined.		Water and electricity assets must be separated prior to closing.	

3.0 Operations/Electricity System & Logistics

The following are key area comments resulting from the Thessalon due diligence exercise. Although much was accomplished, only general summary comments are made except where opportunities/risks are noteworthy.

TRANSPORT & WORK EQUIPMENT:

No transport and work equipment is involved in this purchase.

INVENTORY

Hydro One will purchase the majority of the inventory owned by Thessalon. However, **46 transformers, which are perceived to be of no value to Hydro One, will be excluded from this purchase.**

OPERATING

Operating Voltage 14400/2400 V
HEC does not have distribution maps.
HEC has two MS's.

STREET LIGHTS

The Town of Thessalon will own and maintains streetlights.

SERVICE CONTRACTS (in or out)

Thessalon HEC has a maintenance agreement with Harris for customer system.

Meter testing is done by Northern Meter Services yearly for an annual fee.

DAMAGE CLAIMS

No outstanding damage claims.

TROUBLE CALLS
Average of 1 / month. Response Time: per OEB rural commitment within 99 minutes

JOINT USE AGREEMENTS

No need for Joint Use Agreement with Bell Canada.
Thessalon HEC has 70 attachment on Bell poles. Bell has 110 attachments on Hydro poles.
Regional Cable Systems have 318 attachments on Hydro poles (per an audit
Joint Use Agreements will not be assigned to Hydro One. Hydro One has master agreements in place with both parties.

LICENCE/PERMITS

No licences or permits

RIGHTS OF WAY

The HEC has no registered/unregistered easements.

REAL PROPERTY (Owned/Leased)

Hydro One will be acquiring no buildings. It will be acquiring two MS properties.

4.0 Environmental

Thessalon HEC has not tested their distribution transformers for PCBs. These will be consolidated with HONI assets and tested.

HONI will be acquiring two substation properties. These properties will be scrutinized for environmental concerns. ES&A has been awarded the work to investigate and provide a report.

HONI is not acquiring any PCB storage or waste generator liabilities.

ENVIRONMENTAL TEST RESULTS

Both MS sites have been tested and no contamination was found.

5.0 Customer Service

- Number of Customers ..... 729 total, 116 general service, 602 residential and 11 demand
- Four customers own transformers.
- No water heater rentals, 5 sentinel light rentals.
- Meter reverification program for 2000 is complete. Approximately 80 reverifications are still to be done for 2001.
- Customers have no telephone numbers in system.
- One metering installation uses voltage stepped down from primary and CT's at secondary – this is a non compliant installation and must be changed.
- Meter reading is done by internal staff.
- Meter reading is done on a bi-monthly basis for residential and monthly for commercial.

Conclusion: The customers of this Utility should easily integrate to Hydro One.

6.0 Financial

A financial due diligence, desktop review, has been completed. The desktop review includes a review of the financial statements included in the original submission, and current financial information available. The scope of work did not include either visiting the MEU or discussing any matters or issues with the Utility's accountant.

The utility was incorporated on October 25, 2000

SUMMARY FINDINGS

At the time of preparation of this document, October 27th, negotiations with Thessalon were continuing in respect to what Hydro One would be acquiring from Thessalon. Therefore, the financial due diligence commentary deals with working capital issues as well as fixed assets, as items included in both categories could potentially be in scope. This review is based on the December 2000 audited financial statements as prepared by Dennis R. Thompson, a local chartered accountant.

The current expectation is that the transaction would see Hydro One acquire only the net fixed assets. Current working capital would be retained by the municipality and would not be part of the transaction. Hydro One would act as predecessor company's agent in the collection of accounts receivable.

The suggested purchase price is $595,000 a multiple of 1.2 times the NBV of the 1999 fixed assets of $491,431. It is recommended that the price adjustment clause within the agreement be based on the multiple of the net book value being acquired. Most disputes have occurred as a result of a decline in book value between the purchase date and the closing date. A mechanism based on book value encourages the utility to continue to maintain the purchased asset book value through until closing.

The purchase price for Thessalon is based on its December 31, 1999 balance sheet. Through a lack of investment the value of this utility has deteriorated since that date.

The adjustment in NBV should be based on net decrease in book value after adjustment for excluded assets with a reduction in value of 1.2 times (multiple that we paid in excess of 1999 book value 595/491 = 1.2 times i.e. we assessed a value of $1.20 for every $1.00 of assets). In this manner Hydro One would not be subject to argument about depreciation/average depreciation or appropriate spending. The working assumption is that spending would be in the normal course and would be sufficient to maintain book value otherwise they are getting a benefit by stripping out depreciation in cash and by us paying more for less.

In the case of Thessalon the book value may have declined by as much as $65,000 from the 1999 net asset value of $491,000, assuming that there has been no reinvestment in that time period and that the transaction is completed by December 31, 2001. **The potential decline and the need for a mechanism to address the reduction in the fixed asset book value should be addressed in the agreement. It appears as if this utility has failed to make any significant additional investment in its infrastructure since December 31, 1999. At December 31, 2000 the fixed asset book value had deteriorated by $38,000 or roughly the annual depreciation amount. Investment in the system amounted to $9,000.**

If Hydro One acquires the Working Capital along with the fixed assets, then the purchase price would increase by about **$ 203,690**. This figure is derived using the December 2000 financial statements and assumes that the utility

would be responsible for amount owed to the Muncipality. Current assets totaled $386,000. Current liabilities other than amounts owed to the municipality totaled $182,044. The calculation does not include current liabilities owed to the Municaplity as follows:

- Accounts payable to the town of Thessalon of $ 56,110; and
- Note payable to Thessalon of $ 321,148.

If these amounts were included the working capital deficit would be $173,568.

Neither of these amounts was listed on the October 2000 closing balance sheet of the former Thessalon Hydro Electric Commission.

It would not be recommended that Hydro One assume the promissory note to the Municipality in the amount of $ 321,148. While this may appear to assist Thessalon in its attempts to minimize transfer tax it is possible that the structure might be considered by the Ministry of Finance as an attempt to avoid trasfer tax. If Hydro One intends to acquire the note payable as part of the transaction i.e. fixed assets less note payable) then tax advice should be sought prior to entering into the transaction.

It is not recommended that Hydro One acquire the working capital of this utility

The bank account has a blend of both water and electricity monies, as does the receivables listing. Separation of water assets from electricity assets is typically difficult to accomplish. If there is no split of the assets transfer tax will have to be paid on the water portion also.

The balance sheet includes an asset named "Qualifying Transition costs" in the amount of $32,392. The asset is a capitalized legal fee and is along term asset, It is not included in the working capital calculation above. The asset has no value to Hydro One as it relates to the incorporation of the utility in October 2000.

It is recommended that Thessalon be responsible for all the payables and the return of customer deposits. These costs can be netted against the amount of receivables that are collected and the company can ultimately be wound up and the net proceeds distributed after applicable tax.

DETAIL FINDINGS

All amounts unless indicated otherwise are as at December 31, 2000.

Current assets

Cash: The statement shows an amount of $ 111,324 of cash. If the working capital is acquired then the bank account would have to be transferred over to Hydro One at close. There are water funds in this account.

Accounts receivable: The amount shown on the December 2000 statements is $ 171,800. The receivable listing at October 1, 2001 shows an amount of $ 86,342.05. Of this amount $22,019.79 or 25% pertains to water accounts. An aged listing was not provided so a determination of the aging of the receivables is not possible. If we do acquire the current assets, then it is recommended that we assume only the current receivables and nothing over 90 days. If we

acquire only the fixed assets, then the receivables will go back to the municipality for collection and we will transfer over all customer accounts with a zero balance.

Inventory: The amount shown at December 31, 2000 is $ 57,889. There should be a physical count performed prior to close and an assessment of what is good, and what is of value to Hydro One. Often times the value of what we are purchasing can be minimized or better yet optimized by having the municipality sell any obsolete items prior to close. This would require a Hydro One Supply person to perform due diligence prior to close. Inventory should be purchased separately and not included in the fixed asset balance. To ensure consistency inventory included in fixed asset in 2000 should also be excluded to ensure that the measurement of change in the fixed asset balance since 1999 is consistent.

Unbilled Revenue: The amount as stated is $ 44,923. If we acquire the working capital then the final bill that Thessalon sends out should be as close to the closing date as possible to minimize the estimating error of Unbilled Revenue. If Hydro One decides to purchase only the fixed assets, then Thessalon should fix the closing date to the date of the final bill. By doing this Hydro One will get full and actual benefit for the power that we sell after the close of the sale.

Prepaid expenses: There is an amount of $ 798 on the statements. This is of no value to Hydro One.

Current Liabilities: At December 31, 2000 this amount was $ 208,728.

Customer deposits – Current: The amount is $ 18,571. These should be applied to the customer accounts so that their balance is zero, and if there is an amount in excess of what the customer owes, then they should receive a cheque from the municipality in that amount. If Hydro One is acquiring the working capital, then the municipality would be reimbursed for the overpayment amounts paid back to the customers.

Fixed assets

Using the December 2000 fixed asset value of $ 453,630, the following is detail of the assets and exclusions:

Plant:	$ 400,379
General office	$ 18,397
Rolling Stock	$ 20,581
Miscellaneous stock	$ 14,273
	$ 453,630

At December 31, 1999 fixed assets were $491,431. The recorded book value before adjustment for excluded assets at December 31, 2000 was $453,630 or a decline of $38,000 or 8% of the purchase price. This is approximately equal to the annual depreciation expense. Assuming no reinvestment the book value will continue to decline at the rate $35,000 per year.

The valuation model assumed excluded assets of $20,000 and a book value at December 31, 1999 for the fixed assets of $471,000

Excluded assets are:

Buildings and fixtures	$ 33,336
Street lighting and signal systems	$ nil
Office equipment	$ 2,909
Computer hardware	$ 15,488
Transportation equipment	$ 20,581
Tools shop and garage equipment	$ 13,912
Plant materials and operating supplies	$ 19,271
	$ 105,497

Using the December 2000 audited fixed asset values with the associated exclusions, and a net book value of fixed assets excluded of $105,497, the acquired asset value would be $348,134. Adding back $20,000 to address the estimated excluded asset the adjusted net book value as at December 31, 2000 would be $368,134. On a 1.2 times multiple the value paid for the utility should be $441,760.

The financial projection model has assumed that fixed assets at December 31,2000 would have been $527,000

Reviewed By:	**Yury Tsimberg** Manager – Integration Planning & Due Diligence Coordination Network Management	**Date**
Approved By:	**Don McInnes** Integration Leader Mergers and Acquisitions Network Management	**Date**

MEU Name:	Thessalon							
Existing Condition							Specific Work required to Bring Assets up to acceptable operational standards (safety, reliability)	
Equipment Category	Poor (% of Total)	Fair (% of Total)	Good (% of Total)	Excellent(% of Total)	Estimate of Units		**Make Safe Work Required** *(immediate attention required)*	**Operation Standards Work Required** *(5 Year Plan for Sustainment)*
PUC Owned Poles Non JU Poles -3 Ph.			20%	80%	60			
PUC Owned Poles Non JU Poles -2 Ph.			10%	90%	6			
PUC Owned Poles Non JU Poles 1 Ph.			10%	90%	2			
PUC Owned Poles JU Poles - 3 Ph.	10%		20%	70%	243			11 DDL poles to increase height, 25 pole to increase height
PUC Owned Poles JU Poles - 2 Ph.	25%			75%	109			25 % to change to higher poles
Just poles	25%		35%	75%	95			
OHSC Owned JU Poles								
Bell Owned Joint use Poles - 3Ph.				100%	3			
Bell Owned Joint use Poles -2 Ph.	10%		10%	80%	10			1 red band
Primary Conductor - 3 Ph.	50%			50%	13.8 Km			50 to 75 % copper to change to alum.
Primary Conductor - 2 Ph	75%			25%	6.1 Km			
Primary Conductor - 1 Ph.	100%				19 Km			
Secondary Conductor	10%		30%	60%	13.5 Km			23 spans open buss to change to spun buss
Primary underground conductor - 3 Ph.	20%			80%	19 Km			450m oil filled potheads to be replaced
Overhead Transformers	100%				125		To be PCB tested	
Padmount Transformers	100%				5		No stickers	
Safety and Environmental Concerns							Specific Work required to Bring Assets up to acceptable operational standards *(safety, reliability)*	
	Possible PCB Contamination in %	Penta Poles as % of Total	Restricted Equipment - Specific Description plus percent of total	Other! Please specify			**Make Safe Work Required** *(immediate attention required)*	**Operation Standards Work Required** *(5 Year Plan for Sustainment)*
Poles								
Conductor								
Underground Cable	100%			450 m			PCB contaminated Pot heads	
Transformers	100%			125			PCB testing required	

MEU Name:	Thessalon							
Distribution Stations							**Specific Work required to Bring Assets up to acceptable operational standards** *(safety, reliability)*	
Name/Reference	Primary Voltage	Secondary Voltage	Equipment be used elsewhere on OHSC	Possibility of PCB Contamination	General Condition	Leaks/Soil Contamination	**Make Safe Work Required** *(immediate attention required)*	**Operation Standards Work Required** *(5 Year Plan for Sustainment)*
MS # 1	14,400	2,400	Yes	OK	Fair	NO	Heaving fence	
MS # 2	14,400	2,400	Yes	OK	Fair	Yes - seal	Replace seal, gravel required to grade up to fence to decrease opening between ground line & fence	
Forestry							**Specific Work required to Bring Assets up to acceptable operational standards** *(safety, reliability)*	
Average Tree Density per kilometer	% of trees within 1 meter of Primary Conductors						**Make Safe Work Required** *(immediate attention required)*	**Operation Standards Work Required** *(5 Year Plan for Sustainment)*
Minimal	20%						2 men 80 hours	

MEU Name:	Thessalon

Other Safety Concerns and Comments

	Lines	Forestry	Techs	Customer Service	
OHSC Service Location that could guarantee 60 minute response time by Lines, Customer Service and Forestry :	Algoma	Algoma	Algoma	Algoma	
Minimum Response time in minutes	60 min	60 min	60 min	60 min	
Number of OHSC Field Staff That Currently Live in The Municipality:	Unknown	Unknown	Unknown	Unknown	

MEU Name:	Thessalon			
Estimate of Urgent Make Safe Work				
Equipment requiring replacement	Units	Unit Price *(estimate by Analyst)*	Subtotal *(estimate by Analyst)*	Comment
# Poles Requiring Replacement		4000	$	
Spans of 3 phase conductor requiring replacement		1000	$	
Spans of 1 phase conductor requiring replacement		600	$	
Station insulators requiring replacement			$	
Pole top insulators requiring replacement		650	$	
Reframing due to substandard clearance *(hazardous)*		700	$	
Pole mount transformers		1500	$	
Padmount transformers		5000	$	PCB Testing
Soil remediation - base of pole			$	
Soil remediation - Station			$	
Soil Remediation - Work Centre			$	
Forestry	80	190	$	15,200.00
Other	1	5000	$	5,000.00 Station fence repairs/gravel, etc.(public safety)
Contingency	25%		$	5,050.00
Total Makesafe Estimate			$	25,250.00

Rights of Way		
Category		**Comments/Specifics**
Colour of Poles		No Bleaching
Ground at base of pole	Good	
Evidence of site being used for other activities (waste storage, spare equipment storage, pesticide storage	No	
Proximity to Sensitive locations	No	
Adjacent land uses that could lead to contamination of the work site	No	
Ground	OK	
Evidence of stressed vegetation	No	
Excavations/berms	No	
Electrical equipment (transformers, regulators, capacitors, etc.)		PCB Testing
Lines and hardware	Good	

Stations Condition Assessment

Stations				
Category	Station 1 - Equipment and Property	Station 2 - Equipment and Property	Station 3 - Equipment and Property	Station 4 - Equipment and Property
Vintage	Faded but old	faded		
Storage Tanks of Gasoline, Diesel, Furnace Oil etc.	No	No		
Evidence of site being used for other activities (waste storage, spare equipment storage, pesticide storage	Yes	No		
Proximity to Sensitive locations	Residental	No		
Adjacent land uses that could lead to contamination of the work site	No	No		
Ground	Good	Good		
Evidence of stressed vegetation	Good	Good		
Excavations/berms	Good	Good		
Comments	Heaved fence	Kids could crawl in between fence and ground line		

Rights of Way		
Category		**Comments/Specifics**
Colour of Poles		No Bleaching
Ground at base of pole	Good	
Evidence of site being used for other activities (waste storage, spare equipment storage, pesticide storage	No	
Proximity to Sensitive locations	No	
Adjacent land uses that could lead to contamination of the work site	No	
Ground	OK	
Evidence of stressed vegetation	No	
Excavations/berms	No	
Electrical equipment (transformers, regulators, capacitors, etc.)		PCB Testing
Lines and hardware	Good	

Work Site
Condition Assessment

Work Centres			
	Category	**Yes/No**	**Comments/Specifics**
	# of Work Centres	Yes	
If Work Centre is PUC only	Are Work Centres Jointly occupied by PUC and Public Works	Yes	Same yard different building
	Storage Tanks of Gasoline, Diesel, Furnace Oil etc.	No	
	Evidence of site being used for other activities (waste storage, spare equipment storage, pesticide storage	No	
	Proximity to Sensitive locations	No	
	Adjacent land uses that could lead to contamination of the work site	No	
	Ground	No	
	Evidence of stressed vegetation	No	
	Excavations/berms	No	

Energy Probe Research Foundation (EP) INTERROGATORY #6 List 1

Interrogatory

Ref: Exh. D2/T 2/S 3 (Ref#: D8)
Issue 4.2: Are the amounts proposed for 2008 Capital Expenditures appropriate?

a) This schedule discusses the need to upgrade the 44 kV supply and distribution system in the Brockville area. How much of the system to be refurbished was originally owned by the municipal utility acquired by Hydro One?

b) Please provide details of the acquisition of the municipal utility specifically:

i) The cost of the acquisition

ii) Any studies that Hydro One conducted on the value of the utility

iii) Any reports that Hydro One had on the condition of the utility's assets

Response

a. All of distribution system under this project was originally owned by the municipal utility.

b.

i) The cost of the acquisition was approximately $13.8 million
ii) Please see attached copy of the Brockville Due Diligence Report prepared prior to completing the acquisition (Attachment A).
iii) Please see attached copy of the Brockville Asset Condition Assessment that was prepared prior to completing the acquisition (Attachment B).

hydro one

Brockville HEC
Due Diligence Summary Report

DISTRIBUTION:

J. Boyer
G. Carleton
C. Cartwright
E. Davison
M. Della Rosa
W. Kloostra
W. Manley
G. O'Neill
A. Pantusa
L. Poirier
R. Seethapathy
S. Struthers

Jan 24/01
Date

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1.0 Background & Observations

- This report summarizes key issues and comments as a result of M&A due diligence efforts on **Brockville HEC**.
- **Brockville** is a utility with **24 full time employees** and **9630** customers.
- Brockville is a share purchase agreement.
- Due diligence issues in this report have been organized based on a checklist of priorities developed and updated by M&A.
- The customers of this utility would be easy to integrate into the Hydro One system.
- **The due diligence efforts discovered a number of contaminated sites that should be re-mediated by the utility prior to closing. Otherwise, the associated re-mediation costs would have a material impact on the deal. There are no more issues that would materially impact the deal assuming the purchase prices is adjusted in accordance with recommendations and accept for potential liabilities in section 6.0.**

2.0 Executive Summary

Section	Observation	Impact	Suggested Course of Action	Comments
Operations Walter Kloostra	Distribution facilities are located on 15 municipal properties		Request the Municipality to grant registered easements to H1 at each of these 15 locations.	
	The utility has a joint use agreement with the Cogeco TV (former Brockville Cable).		The HEC should notify the cable company of their sale to H1 and advise that H1 will contact the cable co. to consolidate their agreement into an existing H1 agreement.	Integration Issue
	The HEC is a member of Enerconnect.		Request the HEC terminate their membership prior to closing.	
Environmental Walter Kloostra	TPH contamination has been found at MS #1, 4, 5 and the PUC main yard.		Brockville HEC is to proceed with re-mediation to be completed prior to closing, and provide H1 with the required documentation.	
	Borehole #4 at MS #2 provided conflicting lab results for PCB validation testing.		Brockville HEC is to resolve conflict and proceed with re-mediation prior to closing if required and provide H1 with the required documentation.	
	H1 will maintain the existing waste generator and C of A for PCB storage.		Request the HEC dispose of all existing waste, PCB and other, prior to closing and provide H1 with the required documentation.	
Customer Service/Metering Steve Vance	All year 2000 meter re-verifications will be completed by closing. The HEC will then embark on year 2001 re-verification.		H1 will lend the HEC meters, thus reducing labour costs for changing meters and allowing these meters to remain with the H1 large sample groups thus reducing meter testing within the utility.	
Financial Doug LaFramboise	Net assets may be overvalued due to pre-paid expenses, general office and computer equipment, and computer software deferred charges.	NBV $140,361	Adjust purchase price accordingly.	
	During 1999 the HEC did water and sewer billing for the Municipality.		On closing, H1 to verify they have not received any water or sewage receivables.	
	There is a $36,168 cash deposit with the City of Brockville, which relates to deferred development charges.		Request the HEC to settle this issue with the City prior to closing so that H1 does not inherit this liability.	
	There is $231,760 due to the Water Department and $3,312 due to the City of Brockville.		Request the HEC settle these debts prior to closing.	
	The Utility provided water and sewer billing service to the municipality.		Verify receivables to ensure that only hydro related liabilities are assumed by H1	Integration Issue
Human Resources Rossana Broderick	The HEC has 24 full time employees.	Annual payroll is $1,229,241.	The 24 full time employees will be transferring to H1.	Integration Issue

	The HEC has 7 pensioners with retirement benefits and 24 employees with post-retirement benefits.	$600K NPV for post-retirement benefits for 24 employees and $175K for the 7 pensioners.	Adjust purchase price accordingly.	
	Some of the employees are former Ontario Hydro pensioners and, thus, can not become regular employees of H1.		Provide employment arrangement other then regular full time employment with H1, e.g. contract.	Integration Issue
	There are no liabilities associated with human rights cases, grievances or arbitration.	None		Integration Issue
	There are no vacation cash out provisions.	None		Integration Issue
	There is a "retirement medical benefit".		Have the Utility provide the details and terminate before closing.	Integration Issue
	The HEC has one outstanding WSIB case.		Request the HEC to finalize this case prior to closing. If this is not possible, adjust the purchase price accordingly.	
	The HEC has one outstanding severance agreement.		Request the HEC to provide details regarding this agreement and adjust the purchase price accordingly.	
	The HEC has $21,473 outstanding on a "computer loan" program with employees.		H1 will arrange for payroll deductions to complete repayment of these loans.	Integration Issue

3.0 Operations/Electricity System & Logistics

All assets, contracts, insurance policies, service agreements and joint use agreements are adequately described in the by-law transfer document (schedules have detailed listing of the above) which was used to facilitate the formation of Brockville Utilities Inc. by the municipality and are an integral part of the 'share purchase' agreement.
Additionally, a 110 page document listing all easements was provided (registered and unregistered). A copy will be forwarded to Legal for inclusion of closing activity (conveying registered easements & forwarding remaining list to Real Estate for inclusion in R I S).

Joint use with Brockville Cable does not need assignment as Cogeco Cable has recently purchased them. Hydro One has agreements with Cogeco Cable. No assignment of Bell joint use required.

Building operating costs are reported at $189K for 1999(taxes inclusive).

A listing of 15 municipal property locations, dated 8 Nov '2000 from John Nause to Gord Eamer, where distribution facilities are present, was provided to Walter Kloostra. The municipality will need to grant registered easement to Hydro One in these locations to ensure operational capability of the assets we are acquiring.

Brockville Utilities Inc have 8 documents containing due diligence information that they made available for viewing and copy. This was prepared for a previous transaction that failed. No additional information requirements appear to be necessary. This information was available for review to all undertaking due diligence on behalf of Hydro One.

4.0 Environmental

The environmental due diligence is a collaborative effort between the City of Brockville and Hydro One. Bowie Environmental Edge was contracted to do the assessment, with Hydro One ES&A acquiring split sample to validate the analytical testing. Hydro One's screening protocol was used for the initial screening. Bowie's report would report results, reliance letter provided to Hydro One and copies of the Phase I and preliminary Phase II work was received.

The attached exerpt:

> **Further to our teleconference Wednesday and follow-up Thursday, the following are the areas requiring further work respecting 'fee simple' land which Hydro One will be purchasing, free of contamination:**
> **MS #1 requires TPH re-mediation**
> **MS #2 requires PCB validation testing @ borehole #4 due to conflicting lab results**
> **MS #4 requires TPH re-mediation**
> **MS #5 requires TPH re-mediation**
> **PUC Main Yard requires TPH re-mediation in the vicinity of Borehole #171 trust this reflects agreement we had after Thursday's conversation and satisfies the needs of the legal agreement respecting environmental due diligence.**

reflects the status to date. This satisfied the legal agreement clause to have this due diligence activity largely completed prior to 31 Dec'00. Brockville will proceed with re-mediation based on the above.

1151 pre-1980 transformers exist in Brockville that will require PCB testing. A transformer listing was provided and is available.

The waste generator and C of A for PCB storage should be maintained as Hydro One will be re-locating to the Brockville Hydro site.

The PCB storage site should be void of existing waste upon closing.

5.0 Customer Service

Customer

- Brockville is located approximately 3.5 hours east of Toronto on Hwy 401
- Brockville Hydro has a customer base of 9,630 customers made up of 304 demand, 913 general service, 6,345 residential non-electric and 2068 residential electric heat customers.
- Most (70%) of the customer pay there bills at the bank, which will make it easy for Hydro One to eliminate a cashiering service at the HEC
- They also have 2000 customer set up as preauthorized with the bank which again is a favoured way to pay Hydro One
- All residential meters are read quarterly and even some commercial are read quarterly. Demand type customers are read on a monthly basis
- Customers are actually billed monthly on an estimate for 2 bills and an actual on the 3rd.
- They also have 1 TOU customer
- The customer System is a Harris system and all customer information can be downloaded
- The utility can even download the information electronically. – If the integration comes sometime after March chances are we can take their electronic file and transfer customer information into CSS electronically saving the labour intensive cost of inputting customer information manually.
- The utility also owns a billing and stuffing machine which could prove beneficial to Hydro One either as an addition to one we have or to put into a utility i.e. Brampton to have bills issued until integration occurs – issues 1000 bills per hour
- Brockville uses the radix system and handhelds for reading meters – the capital cost of these units is quite expensive ($3,500). These are the same as Hydro One uses and would be able to be utilized upon integration with the change of a download file and new initialization.
- The utility has no water heater rentals, however it has substantial sentinel lights (approx. 600). This program is not being offered any more and would be transferred to Hydro One.
- The municipality owns the streetlights and will have a 3rd party do maintenance in the future after transition.
- Meter reading is done using in-house staff, these staff could probably be utilized as meter readers in the future.

Customer Integration will be smooth as all data is available and maybe available for input electronically which reduce integration costs
Moving customers to bimonthly billing will add 2 more meter reads per year but will reduce actual bills to customers to 6 which reduces required stock and mailing costs and also bills issued will be actual reducing the call handing that would be required on estimated bills as is done now.

Metering

- Meters are tested in groups which for economies of scale will reduce testing costs in future – These groups maybe able to be moved in to existing Hydro One meter testing groups which would further reduce the costs.
- All meter reverifications are just about completed for 2000 and utility will embark upon doing 2001 in the near future. Hydro One will lend them the meters thus reducing our labour costs for changing meters and also allowing these meters to remain within the Hydro One large sample groups thus reducing meter testing within the utility.
- All meter information is available electronically which will reduce analysis and input time
- All metering components are available and staff is willing to input these on a spreadsheet thus reducing integration costs by having our staff do this work.

Metering is in good shape and integration costs and post O&M costs should be reduced by using the programs to the fullest mentioned above.

6.0 Financial

A financial due diligence review has been completed, which included a review of the financial statements included in the original submission, current financial information available and visit to the Utility to review their prior year end working papers.

SUMMARY FINDINGS

This is a very well managed (financially) Utility. There are 9,427 customers and 24 full-time employees, all of which will be coming to Hydro One.

Based upon the review of the audited year-end 1999 financial statements, net assets may be overvalued by $ 140,361 ($ 37,148 prepaid expenses, $ 46,652 NBV general office equipment, $ 44,757 NBV computer equipment, $ 11,804 computer software [deferred charges]). Further, the fixed assets total includes construction in progress with a total of $ 329,003.

There is $ 64,398 of land and $ 3,522 of fully depreciated land rights (NBV = 0) associated with this utility. There is $ 888,308 NBV buildings as at year-end 1999.

Potential exposures that have been mentioned before and will not go into detail are (1) The contingent liability (2) The pooled MEARIE insurance plan.

This Utility has non-regulated assets, meters, included and maybe a separate agreement is needed.

During 1999 the Utility provided water and sewer billing service for the Municipality. On closing, a verification/audit of receivables should be performed to ensure that Hydro One is not assuming any water associated receivables.

The utility rents out office space to the Water Department, which was $ 50,004 in miscellaneous revenue for 1999.

There is $ 36,168 cash on deposit with the City of Brockville, which relates to deferred development charges of the same amount. This should be settled prior to close so that Hydro One does not assume any of this liability. Both these amounts should be included in the working capital calculation.

A closing date audit is recommended. This is recommended more to facilitate the integration process.

DETAIL FINDINGS

Findings and comments follow:

1. Bennett Lewis McMahon Stillar is a small Brockville firm that completed the audit.

2. The allowance for bad debts as recorded at the end of 1999 is $ 211,000, which seems to be reasonable given the utility's history of bad debts. It has been recommended to the utility to write these off prior to closing.

   There is $ 133,562 in receivables from the City of Brockville at year-end 1999.

3. Unbilled Revenue at year-end 1999 is $ 1,947,701. It is to be adjusted to actual billings on closing and therefore any potential gain or loss will be crystallized. Upon closing the power receivables will be required to be detailed, and an appropriate allowance for bad debts calculated.

4. Inventories on hand at year-end 1999 are approximately $ 550,239, which consists of transformers and meters. The closing date amount will be audited however the auditors may not be able to do an adequate job determining the amount of slow moving inventory/assets. Given that the amount is significant I would suggest we rely on the

auditors work and also have one of the Hydro One operation personal review the inventory. This decision is to be made by the Transaction and Transition Manager.

5. Fixed assets are reconciled and include distribution lines, feeders and transformers. The Utility has rolling stock, with a NBV of $ 109,654 at year-end 1999.

   Net book value of meters distribution assets is $ 635,187 at year-end 1999.

   The Transaction and Transition Manager will be reviewing the fixed assets and advise if all are useable by Hydro One.

   Depreciation expense is determined in accordance with standard practices. However Hydro One rates result in longer useful lives and less annual depreciation. This should be factored into the equation. Depreciation expense approximates $ 674,000 per year.

6. The single largest payable is the energy bill with OPGI.

   There is $ 231,760 due to the Water Department and $ 3,312 due to the City of Brockville at year-end 1999. These should be settled prior to close.

   There is a large amount of customer credit balances, $ 389,161 at year-end 1999.

7. GST/HST is filed and paid quarterly. It is also subject to audit. There have been no GST assessments. The agreement will have the standard clause that the Utility is current with all taxes including any reassessments.

8. Human resource considerations – The utility has 24 full time employees (all of which will be coming to Hydro One). Filings of WSI, EHT, EI or employee withholdings appear to be up to date with the annual filings. There is a standard clause that should be included in the agreement that indicates the Utility is current with all filings including any reassessments, if any.

9. No information was provided as to the number of retired employees are carried by the Utility. We will need to determine what benefits plans there are and how many employees are using them, how many are eligible, and a cost estimate if possible.

   The Commission does make contributions to OMERS on behalf of staff members. The amount contributed in 1999 was $ NIL, and was $ 27,685 in 1998. As at year-end 1999 the Electric Department had no unfunded liability under the past service provisions of the OMERS agreement.

10. There are legal agreements - joint service agreements and Legal should request along with any others. There are no legal claims against the company. Legal may want to get the details and handle appropriately in the agreement.

11. This Utility is still a member of Enerconnect.

12. If the transaction is to proceed we require insurance claims history.

13. The margin decreased from 7.2 % in 1998 to 6.0 % in 1999.

14. The Brockville MEU has incorporated.

15. It is assumed that M&A will perform standard environment assessment procedures on this utility.

7.0 Human Resources

Questions	Brockville
Total # of employees	24
Total Payroll Costs	Total payroll dollars provided by Vendor: $1,229,241.40 Based on the individual dollars provided, total payroll costs amount to: $1,232,216. Brockville Revised.xls
Number of former OH employees or pensioners.	2 – [redacted] (scheduled to join Hydro One), [redacted] (apparently not joining Hydro One). – both pensioners. ***Note: [redacted] will not be a "regular" employee as he is not eligible to re-enrol in the Hydro One pension.***
Are any of these former OH employees receiving an OH pension?	Yes.
Total number of Pensioners	7
Details of post-retirement benefits	Life insurance for life and health & extended benefits till the age of 65. Premium costs for these post-retirement benefits **will not** be provided by the MEU. In absence of this information, approximate premium cost for these employees are as follows: Pensioners (7): $175K NPV Employees (24): $600K NPV **Total cost: $775K NPV**
Any outstanding Severance Agreements?	MEU is not willing to provide this information.
Name & Local of any Collective Agreement	CUPE Local 1309. Copy not provided.
Any outstanding grievances, arbitrations?	No
Any staff on LTD?	No
Outstanding WSIB cases?	Yes. 1. [redacted].
Outstanding human rights cases, or other legal actions due to employment issues.	No

Questions	Brockville
Outstanding loan programs. Details.	Details of the loan program have not been provided other than it's a "Computer Loan" program. Breakdown as follows: [redacted] - $1103.15 [redacted] - $2657.28 [redacted] - $1102.03 [redacted] - $269.94 [redacted] - $2720.00 [redacted] - $1924.46 [redacted] - $2981.83 [redacted] - $2422.80 [redacted] - $807.08 [redacted] - $2330.00 [redacted] - $115.50 [redacted] - $384.72 [redacted] - $791.78 [redacted] - $1953.83 **Outstanding balances amount to: $21,473.40.**
Any sick leave cash out provisions?	They have "retirement medical benefits". Details not provided.
Any vacation cash out provisions?	No.

Reviewed By: **Yury Tsimberg** Date: Jan. 19/01
Manager – Integration Planning &
Due Diligence Coordination
Network Management

Approved By: **Don McInnes** Date: Jan 24/01
Integration Leader
Mergers and Acquisitions
Network Management

Attachment B

Brockville Asset Condition Assessment

MEU Condition Assessment
Brockville

Existing Condition						Comments
Equipment Category	Poor (% of Total)	Fair (% of Total)	Good (% of Total)	Excellent(% of Total)	Estimate of Units	Specific Work required to Bring Assets up to acceptable operational standards (safety, reliaility)
Poles	0	10	80	10	2233 (334 are 44kv) of these approx 30 are cement line poles	Minimal pole replacement, minor betterment
Primary Conductor	0	0	80	20	27.2 km of 44kv & 2 km of 44kv underground & 55.2km of 3ph 8kv & 19.3 km of 1ph & 23.3 km of 3ph underground & 7.0km of 1ph underground 11-ABS switch 44kv & 35.4 km of 3ph 4.8 kv & 12 km of 1ph & 1.0 km of 3 ph 4.8kv underground & 3.5 km of 2.4 underground	good shape some # 6 copper mostly in the 2400 volt section -- minor betterment
Secondary Conductor	2	10	68	20	79.9 km of sec. 6 km of the total is open wire minal minor betterment required otherwise good shape	good shape some # 6 copper open wire - minor betterment
Transformers	0	10	70	20	300 pole mount 8kv & 418 pole mount 2.4 kv & 46-3ph pad mount 2.4 kv & 89-3ph pad mt.8 kv & 42-1ph pad mt 8kv & 45 -1 ph pad mount 2.4 kv & 9- 3ph sw vaults 8 kv & 2-3ph sw. vaults 4.8 kv & 4-1ph sw vault & 269- comb transformers & st lite 8kv	good shape some framing encroaches on the Lof A minor betterment
Street Lights			100		2173 of that (58 on steel poles- 366 on cement poles- 1547 on poles - 186 decortive type downtown & along the water) the rest are included in the transformer section as they are combination light & transformer	Arch type HPS and combination transformer are mercury vapour
Safety and Environmental Concerns						Comments

MEU Condition Assessment
Brockville

	Possible PCB Contamination in %	Penta Poles as % of Total	Restricted Equipment - Specific Description plus percent of total		Other/ Please specifiy	Specific Work required to Bring Assets up to acceptable operational standards (safety, reliaility)
Poles	0	0	0			about 119 spans of poles and conductor are built back lot construction , the plant is in good shape it is just the innaccessibility
Conductor	0		5%			-- betterment work 242 spans of single phase at various locations are # 6 copper 43 spans of 3 phase is # 6 copper -- minor betterment work
Transformers	100		10%			about 10% of the framing is sub-standard for OHSC standard for PUC to change a transformer it would encroch on Lof A--- betterment work
Distribution Stations						**Ball Park Estimate of Work Required to Bring Facility up to OHSC Standards**
Name/Reference	Primary Voltage	Secondary Voltage	Can Equipment be used elsewhere on OHSC Facilities	Possibility of PCB Contamination	General Condition	Specific Work required to Bring Assets up to acceptable operational standards (safety, reliaility)
Centennial Rd MS metal clad type 5 MVA est 11) the 44kv dips at pole in front of the MS to ed it 30m in length The three feeders are underground from the station to the riser poles average 45m each	44kv	8320	Yes	None	very good	No work required, Assets are present day standards
Parkdale Ave MS 5MVA est (M1) a lattice type station 44kv fed overhead The 3-8kv feeders are underground to riser poles in front of station approx 45m in length each	44kkv	8320	yes	yes	good	No work required, Assets are present day standards, a high wooden fence all around parmeter
Distribution Stations						**Ball Park Estimate of Work Required to Bring Facility up to OHSC Standards**

MEU Condition Assessment
Brockville

Name/Reference	Primary Voltage	Secondary Voltage	Can Equipment be used elsewhere on OHSC Facilities	Possibility of PCB Contamination	General Condition	Specific Work required to Bring Assets up to acceptable operational standards (safety, reliaility)
North Augusta Rd MS metal clad type 5MVA est (M4) 44kv fed overhead The three 8kv feeders are underground to riser poles approx 45m in length	44kv	8320	yes	yes	very good	metal clad type good shape
Legion Park MS 4MVA (2-2MVA) est The 44kv fed overhead The 4 feeders 4.8 kv are underground to risers poles in front of MS approx. 45m in length each	44kv	4800	only if you have other 4.8 kv stations	yes	fair	one transformer seems to have a minor leak--- PCB check needed and seals
Schofield Ave MS Lattice type 5MVA (M1) the 44kv feeds overhead & the 3-4.8kv feeders are uderground to risers poles approx 60 m in length	44kv	4800	only if you have other 4.8 kv stations	yes	good	none
Chruch St MS Tubing type 3MVA (M1) 44kv & the 3 feeders are overhead	44kv	4800	only if you have other 4.8 kv stations	yes	good	insulator changes -- the feeders are fused switches -- install reclosers
George St MS metal clad 5MVA (M1) the 44kv dips at pole in front of the MS to feed it 60m in length The four feeders are underground from the station to the riser poles average 60m each	44kv	4800	only if you have other 4.8 kv stations	yes	good	none - the station has a board fence all around difficult to see in
Water St MS Metal Clad 5MVA (M4) 44kv fed underground approx .7 km The four feeders are underground from the station to the riser poles average 60m each	44kv	4800	only if you have other 4.8 kv stations	yes	good	The 44kv circuit M4 comes in from Pine St and dips to feed the Water St MS (downtown) this is approx .7 km in length, the cable is lead type .

Metering Points	
Location Identification	**Comments**
At the A TS	The City of Brockville has 3 decated feeters out of the TS-- M4,M3,& M1

MEU Condition Assessment
Brockville

	Lines	Forestry	Customer Service
OHSC Service Location that could guarantee 60 minute response time by Lines, Customer Service and Forestry :	Brockville	Brockville	Brockville
Number of OHSC Field Staff That Currently Live in The Municipality:	3 of 15	2 of 6	2 of 5

All the secondary is triplex & open wire & in good shape - some open wire is # 6 copper require minor betterment
Trees not a concern at this time minimal triming required
betterment work 242 spans of single phase at various locations are # 6 copper 43 spans of 3 phase is # 6 copper -- minor betterment work

You will need to replace the # 6 copper conductor and most of it is in the 4.8kv section of the City then you could harvest this system for some years before you carry out any major betterment work
One of the 3 sections of 44kv that dips to underground, feeds the Water St MS is lead cable (.7 km). This looks in good shape,connections are all good. There will be a need to develop a planned program to replace the cable.
The 44kv dips at several locations - #401 hwy, Park St. to feed Hospital, Pine St. to feed Water St MS and then at the various entrances to the MS

Talking to the FLM in Brockville work Centre the PUC can back-feed all of their stations so a MUS is not required and the PUC do their own Maintenance work.

All the PUC poles are numbered so they have an account of their plant . I could not determine the system so I did my own count

Jct use with Bell throughout the town. Bell also have a lot of poles with the service secondaries on them
This would be a excellent investment, there is a lot of industry in this City and from what I have seen a large industrical park that is developed just waiting for more industry.

Energy Probe Research Foundation (EP) INTERROGATORY #7 List 1

Interrogatory

Ref: Exh. D1/T 2/S 1, p. 15 of 20
Issue 4.3: Are the 2008 sustaining capital expenditures for Asset Replacement appropriate?

Page 15 of 20 of the schedule presents wood pole age demographics and predicts replacements of wood poles might increase to 50,000 per year.

Does Hydro One analyze its wood pole data to determine if early replacement of poles is correlated with species and/or treatment type? If so please provide the data.

Response

Page 15 of 20 in Exhibit D1, Tab 2, Schedule 1 does not predict that wood pole replacements might increase to 50,000 poles per year. It predicts that 50,000 poles per year will enter a demographic region (i.e. age bracket) that places them at a higher risk of requiring replacement, where in the past about 35,000 poles have passed into this region. The actual number of planned replacements is expected to increase in future years due to the shifting age profile.

Hydro One has in the past analyzed wood pole data in relation to species or treatment type but it has not conducted an in-depth analysis since embarking on the current data collection initiative that commenced in 2005 as highlighted in Exhibit C1, Tab 2, Schedule 2, page 16.

Hydro One believes that the best means of managing the wood pole plant is to assess poles on an individual basis to determine their condition, while at the same time confirming the location of each pole, the species of pole, the preservative applied and other characteristics such as areas of high ant infestations or rodent damage, and swamp conditions. This approach has been adopted at Hydro One and has been integrated with the aforementioned data collection initiative. The initiative is to be completed in 2010, prior to this Hydro One will conduct further analyses relating pole characteristics to replacement needs so that areas at highest risk of failure can be targeted.

Energy Probe Research Foundation (EP) INTERROGATORY #8 List 1

Interrogatory

Ref: Exh. D1/T 2/S 1, p. 20
Issue 4.3: Are the 2008 sustaining capital expenditures for Asset Replacement appropriate?

Page 20 of the schedule discusses underground and submarine cables. Does Hydro One conduct any in situ diagnostic testing of these cables? If yes, please provide details of the testing and results. If not, please explain why Hydro One does not think that diagnostic testing is a useful technique to evaluate the condition and remaining service life of cables.

Response

Hydro One does not conduct any in situ diagnostic testing of underground and submarine cables.

The use of partial discharge mapping or discharge monitoring to determine condition or predict cable failures is costly. Some urban utilities with high voltage cables that supply commercial centres undertake these programs. Many utilities with lower voltage cables and with lower customer impacts base their end-of-life and replacement decisions almost exclusively on failure frequencies. As Hydro One is predominately a rural utility, these costly diagnostics tools have not been considered cost effective. As well, Hydro One has a relatively new and predominantly XLPE (Extruded Cross-Linked Polyethylene) plant. These cables are not approaching any near-term, widespread, end-of-life issues that will result in increasing failure rates and the need to introduce additional cable testing procedures.

Hydro One is more concerned with ageing submarine cables and the risk of neutral corrosion at the shoreline of water bodies. This risk is being managed using cable inspections and replacement programs.

Given the fact that diagnostic testing is costly and that Hydro One's cable plant is relatively new, Hydro One bases its asset management practices for cables on inspections that are consistent with OEB regulations (i.e. 3-year inspection for urban circuits and a 6-year inspection for rural circuits) and on reliability performance. Inspections are used to examine cable components such as cable terminations, potheads, elbows, switching kiosks and cable riser poles. Cable replacement decisions are generally triggered when a section of cable has multiple failures in a year or when significant neutral corrosion is found in the case of submarine cables.

Energy Probe Research Foundation (EP) INTERROGATORY #9 List 1

Interrogatory

Ref: Exh. D1/T 3/S 3, p. 10 of 18
Issue 4.4: Are the 2008 amounts proposed for Development capital appropriate?

Page 10 of 18 of the schedule describes Hydro One Distribution's plans to install real time data acquisition equipment at strategic locations in its system. Does Hydro One Distribution currently have staff in the OGCC that can be devoted to monitor this data stream or will additional staff be required for this function? If so, how much will this additional monitoring effort cost?

Response

At this time we do not believe that this initiative will require added staffing at the OGCC.

Energy Probe Research Foundation (EP) INTERROGATORY #10 List 1

Interrogatory

Ref: Exh. D1/T 3/S 3, p. 12 of 18
Exh. D2/T 2/S 3, p. 7 of 46
Issue 4.4: Are the 2008 amounts proposed for Development capital appropriate?

Page 12 of D1/T3/S3 discusses the costs associated with connecting generators to the distribution system. Starting at line 19 the following statement appears:

> "Upgrades to Hydro One's distribution lines (poles in particular) may also be required in cases where the customer chooses to make use of Hydro One facilities rather than build their own. Based on Hydro One's experience with joint use, it is anticipated that in these situations, Hydro One will be accountable for 83% of the upgrade costs and the customer will contribute 17%."

Page 7 of D2/T2/S3 (Ref: S6) discusses Joint Use and Line Relocations. Under the Joint Use subheading the following statement appears:

> "The cost sharing provisions in joint use agreements allow Hydro One Distribution to recover its costs resulting from requests to add new attachments to poles. Costs recovered include those to increase pole class to accommodate changes in pole loading, increased height to obtain appropriate ground clearances for public safety, as well as costs associated with premature retirement of in-service assets."

Please explain how these two statements should be reconciled.

Response

As explained in the interrogatory response in Exhibit H, Tab 1, Schedule 23 and Schedule 26, Hydro One charges generators for incremental and advancement costs related to modifications to Hydro One facilities to enable the attachment of generator facilities. These are the costs referred to in the excerpt from page 7 of Exhibit D2, Tab 2, Schedule 3, referenced in the question. As noted in the second reference above to page 12, Exhibit D1, Tab 3, Schedule 3, it is these costs that based on Hydro One's experience will amount to about 17% of the upgrade costs.

Energy Probe Research Foundation (EP) INTERROGATORY #11 List 1

Interrogatory

Ref: Exh. D1/T 3/S 3, p. 13 of 18
Issue 4.4: Are the 2008 amounts proposed for Development capital appropriate?

Page 13 of 18 of this schedule discusses the need for power quality monitoring equipment in the vicinity of wind generation connected to Hydro One's distribution system. Please explain why the cost of this equipment should not borne by the wind generator.

Response

See response to interrogatory in Exhibit H, Tab 1, Schedule 24, part c.

Energy Probe Research Foundation (EP) INTERROGATORY #12 List 1

Interrogatory

Ref: Exh. D1/T 3/S 5, p. 33 of 40
Issue 4.6: Is the proposed level of 2008 Shared Services and Other Capital expenditures appropriate?

This part of the schedule discusses the increased costs associated with replacing aging transport and work equipment. Table 8 on page 33 shows $39.2 M planned for Dx expenditures on TW&E for 2008.

a) Does Hydro One have a policy requiring new vehicles to be flex fuel capable? If so, please provide it. If not, please explain why such a policy would not be prudent in light of fuel price and availability uncertainty.

b) Please describe the process for disposing of vehicles once they have reached the end of their service life.

Response

(a) Hydro One presently has 236 flex fuel capable vehicles.
Although we do not have a policy in place, we have purchased these vehicles in the event that flex fuel becomes more readily available in Ontario.
A policy at this time would not be prudent based on the limited supply of flex fuel plus the limited availability of models which meet our requirements as an electrical utility.

b) All our vehicles are disposed of after a mechanical assessment is completed and a final review and assessment of the total life cycle costs and work program requirements are completed by Hydro One Fleet.

Once the decision is made by Hydro One to surplus a vehicle, it is sent to Inergi LP for disposal via public auction. Inergi LP then sends a report after each sale stating the sale price to the Fleet Asset Manager (Hydro One) and the Fixed Assets Department (Inergi) in order to complete the system accounting processes.

Energy Probe Research Foundation (EP) INTERROGATORY #13 List 1

Interrogatory

Ref: Exh. D2/T 3/S 3, Ref#: IT1
Issue 4.6: Is the proposed level of 2008 Shared Services and Other Capital expenditures appropriate?

This schedule discusses the need to implement new IT infrastructure and contains the statement:

> "We will not customize the product to accommodate current business processes; rather, we will replace current business processes with industry standard practices"

a) Please explain why this decision was made.

b) What is the impact on IT staffing levels of this decision?

Response

(Note the interrogatory references Exhibit D2 Tab 3 Section 3 which is Continuity of Construction Work In Progress. From the question it appears that the intent was to reference Tab 2. This is reflected in the response below.)

a) This decision was made as software customization can complicate vendor upgrading and potentially lead to the vendor being unable to support its product as customized by Hydro One.

The Cornerstone project philosophy is to make changes to corporate processes and to utilize the built in functionality of the application tool to support those processes. This enables the application to be upgraded and business processes to be continually improved through enhancements provided by the application vendor.

b) Without this decision, IT staffing levels would otherwise be higher as it would have been necessary to engage staff to enable customizing the SAP product and to then support the customized SAP product.

As a result of this decision, there is only one SAP IT architect being hired to support Cornerstone.

Energy Probe Research Foundation (EP) INTERROGATORY #14 List 1

Interrogatory

Ref: Exh. C1/T 2/S 6, p. 3 of 84
Issue 4.6: Is the proposed level of 2008 Shared Services and Other Capital expenditures appropriate?

Table 1 on page 3 of 84 shows allocated distribution, shared services and other costs. The line entitled "Other Shared Services" contains credit entries for which the 2007 entry is significantly lower than historic or test year entries.

Please explain what this category includes, why they are credit entries and why the number for 2007 is significantly different than the other years shown.

Response

As noted in Table 29 and described in Section 6.0 of Exhibit C1-2-6 of EB-2007-0681, the "Other Shared Services" category includes capitalized corporate overhead credits, adjustments related to the environmental provision and indirect depreciation, deferred pension costs, and other material unexpected or non-recurring expenses such as insurance rebates, adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments.

The credit entries are required to remove costs from OM&A so that they can be classified in the appropriate category for accounting purposes. For example:

- the Corporate Overhead credit removes costs from OM&A that have been charged to capital projects through the capital overhead rate,
- the Environmental Provision credit removes environmental remediation costs from OM&A so they can be appropriately recorded as amortization expense,
- the Indirect Depreciation credit removes from OM&A the portion of Transportation and Work Equipment depreciation that was charged to OM&A work programs through standard T&WE equipment charge rates, in order to appropriately classify these costs as depreciation expense.

The primary factors contributing to lower 2007 "Other Shared Services" costs are:

- lower overheads capitalized in 2007,
- lower spending on environmental remediation,
- the impact of the OEB decision on pension costs in EB-2005-0368, under which pension costs were deferred until May 1, 2006, and
- costs in 2007 related to the Inergi Pension true-up and Distribution rate hearing preparation costs and other miscellaneous adjustments.

For further details, please see Exhibit C1/Tab 2/Schedule 6, Section 6.

Energy Probe Research Foundation (EP) INTERROGATORY #15 List 1

Interrogatory

Ref: Exh. D1/T 3/S 2, p. 27 of 31
Issue 8.2: Is the proposed 2008 capital spending for the Smart Meter program appropriate?

Page 27 of 31 of the schedule, starting at line 18, describes the "incremental functionality" of Hydro One's smart meter installations. Please confirm that this term means "greater than minimum functionality". If so, has the Board previously approved the cost of this increased functionality or is Hydro One seeking approval for it in this application? If not, please explain why Hydro One has addressed "incremental functionality" as a distinct subject in the smart meter part of the application.

Response

Yes, this term means functionality that is greater than the minimum functionality described in the Minister of Energy AMI functional specification. The Board has only previously approved the costs associated with minimum functionality up to May 31, 2007.

As part of this Application, Hydro One is seeking approval for all smart meter related costs not previously approved by the Board. This includes both minimum and incremental functionality components.

Energy Probe Research Foundation (EP) INTERROGATORY #16 List 1

Interrogatory

Ref: Exh. D1/T 3/S 3, p. 6 of 18
Issue 8.2: Is the proposed 2008 capital spending for the Smart Meter program appropriate?

Page 6 of 18 of the schedule discusses non smart meter planned expenditures. Please explain why any new or upgraded service could not be metered with a smart meter thus avoiding the cost of replacing a conventional meter later

Response

Not every new retail service, or upgraded service, is in the program to receive a Smart Meter. About 1.2 million meters used for residential and other customers whose average monthly demand is 50 kW or less will receive a smart meter. New or upgraded services for customers under this category will receive a smart meter during the initial site visit.

Non smart meter planned expenditures cover metering for about 7,300 electronic demand meters for smaller business customers with an average monthly demand of greater than 50 kW and about 1,300 interval meters for existing business customers whose demand exceeds 1,000 kW and in some cases 200 kW depending on the particular circumstances.

Energy Probe Research Foundation (EP) INTERROGATORY #17 List 2

Interrogatory

Ref: Exh. A/T 3/S 1, pp. 1-2, Table 1
Issue 1.4: Are Hydro One's Economic and Business Planning Assumptions for 2008 appropriate?

a) Please explain why the Applicant uses "business values" to represent "strategic goals" when these two business concepts are normally highly differentiated.

b) Why aren't there quantitative figures attached to the Applicant's 2010 performance targets for Reliability and Employees in Table 1?

Response

a) Hydro One maintains a strong association between its business values and strategic goals and has advanced such an association for years.

Strategic Goals change with changes in the Business environment. Business Values (e.g. Public & Employee Safety, Customer satisfaction, etc), however, are relatively stable for our Business, while, our Risk Tolerances (related to the Business Values) can change based on our Strategic Goals. The changes in the Risk Tolerances ensure our annual risk assessments; the mitigating risk management options and work priorities adjust to achieve our goals.

b) Please see the response to interrogatory in Exhibit H, Tab 11, Schedule 11 with respect to reliability.

With respect to Employees, our aim is to complete 95% of the skill and safety training per employee on an annual basis by 2010. This is a stretch from our 2008 target of 90% completion.

Energy Probe Research Foundation (EP) INTERROGATORY #18 List 2

Interrogatory

Ref: Exh. A/T 14/S 1, p. 3
Issue 1.4: Are Hydro One's Economic and Business Planning Assumptions for 2008 appropriate?

a) Please explain why there are no evident consumer inputs in the formation of the Applicant's "strategic direction." Successful strategic planning normally requires a very heavy influence from the organization's environment, and yet none appears to be evident in this submission. Why?

b) Has the Applicant undertaken a broad encompassing visioning process or charrette since it emerged from Ontario Hydro?

Response

a. Hydro One's key stakeholders have been consulted regarding our level of performance, and this input has been used to help define our mission statement and business values discussed in Exhibit A, Tab 3, Schedule 1. Stakeholder input has come from various sources including:

- Our shareholder
- Customer Advisory Boards (CABs)
- Stakeholder meetings and consultations (including stakeholder sessions that occurred as part of Hydro One's Transmission and Distribution applications)
- Presentation to the OEB and intervenors in previous revenue requirement filings
- Direct customer contact
- Customer surveys focusing on the importance of such attributes as reliability and the importance of price.

Hydro One Distribution is driven by the Corporate Mission and business values and together, they provide the basis to deliver on targeted performance objectives.

b. Each year, the Hydro One planning cycle involves a review and update of the company's over-all strategy and vision. Both the Hydro One Board of Directors and Hydro One senior management, on an annual basis, discuss and revise where appropriate the corporate vision and strategy.

Energy Probe Research Foundation (EP) INTERROGATORY #19 List 2

Interrogatory

Ref: Exh. A/T 14/S 5, p. 3
Issue 1.4: Are Hydro One's Economic and Business Planning Assumptions for 2008 appropriate?

Please report the results of the "customer satisfaction survey" identified in Table 1.

Response

Overall customer satisfaction results, for Hydro One customer segments, are included in table below.

	2007
Overall Customer Satisfaction	
Large Transmission and LDC	95%
Large Distribution Accounts	90%
Residential/Small .Business	82%
Distribution Generators	71%
Transmission Generators	83%

Energy Probe Research Foundation (EP) INTERROGATORY #20 List 2

Interrogatory

Ref: Exh. A/T 14/S 3, p. 20, Table 4
Issue 1.5: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Does the "(total) load forecast, after deducting the impact of CDM," indicate rising electricity demand in 2008 compared to 2007 and 2006 in Table 4? If so, is this rising electricity demand consistent with the Ministerial Directive of June 13, 2006 and consistent with apparently anticipated flat electricity demand identified in the Applicant's Bruce to Milton Transmission application to the OEB (EB-2007-0050, Exh. B, Tab 4, Sch. 3, page 2, lines 2-3)?

Response

Yes, Hydro One Distribution's total load is forecast to increase by 0.43% in 2008 after deduction of CDM impacts provided by the OPA in the IPSP filed with the Board on August 29, 2007. However, this is consistent with the Minister's directive of June 13, 2006 and the Bruce to Milton Transmission Application because the CDM impacts in the IPSP are expected to ramp up rapidly starting in 2009 and as a result, Hydro One Distribution's load forecast beyond 2008 is forecast to decline. For details of the long-term CDM impacts planned by the OPA, please refer to the proposed CDM savings in EB-2007-0707, Exhibit D, Tab 4, Schedule 1, Attachment 4, Table 4.

Energy Probe Research Foundation (EP) INTERROGATORY #21 List 2

Interrogatory

Ref: Exh. A/T 15/S 1, p. 6, Table 1
Issue 1.6: Is the service quality on the OEB specified performance indicators acceptable?

Please report the 2007 "telephone accessibility" results relevant to the entries in Table 1.

Response

The 2007 "telephone accessibility" result is 78.3% of calls answered within 30 seconds.

Energy Probe Research Foundation (EP) INTERROGATORY #22 List 2

Interrogatory

Ref: Exh. A/T 15/S 2, pp. 1-2
Exh. C1/T 2/S 6, pp. 52-53
Exh. C1/T 3/S 2

Issue 1.6: Is the service quality on the OEB specified performance indicators acceptable?

Has the Applicant carried out labour productivity studies with a focus on individual, team or department performance outputs, within the last three years? If so, please report the results. If not, why not?

Response

Hydro One has not "carried out labour productivity studies with a focus on individual, team or department performance outputs, within the last three years".

However, Hydro One has successfully undertaken numerous initiatives to improve labour productivity as discussed in our prefiled evidence (Exhibit C1, Tab 4, Schedule 2, Cost Efficiency) including;

- Developing a more multi-skilled workforce;
- Using new tools and technologies, such as the full implementation of information technology for new connections;
- Using temporary headquarters for work crews, thus reducing travel time and increasing "wrench" time on the job;
- Increasing staffing flexibility (e.g. use of hiring hall) to execute peak seasonal and project work;
- Implementing focused trades training programs; and
- Implementing new processes and tools in the field to enable improved planning, scheduling and reporting of work; and

Also, as discussed in our evidence, Hydro One uses benchmarking and best practice information to find better ways to run its business, thus gaining cost efficiencies and improving work program effectiveness, as well as to provide some indication of progress across the key elements of Hydro One's 2010 strategic goals and performance targets (see Exhibit A, Tab 3, Schedule 1 pages 1 and 2). Hydro One's benchmarking efforts consist of both internal and external studies. Examples include;

- Lowering costs through use of Hiring Hall resources for lower skill manual brush cutting work.
- Reviewing forestry practices to ensure that the most effective methods of forestry management are being used. (e.g. using mechanical brush cutting)

Energy Probe Research Foundation (EP) INTERROGATORY #23 List 2

Interrogatory

Ref: Exh. C1/T 2/S 5, pp. 5-7, 11
Issue 1.6: Is the service quality on the OEB specified performance indicators acceptable?

Does the Applicant regularly carry out professional market research as an evaluation tool for its Customer Care Management system? If so, please report the results for the last three years. If not, why not?

Response

Yes, regular customer research is carried out to monitor the customer care program. Customer satisfaction with the billing program and call handling program is tracked. Information from this research is used to develop improvement programs, then results are monitored in subsequent research studies. The table below provides a sample of some of the results.

Residential/Small Business	**2005**	**2006**	**2007**
Satisfaction with bill handling	76%	82%	76%
Satisfaction with amount of information on bill	86%	89%	90%
Satisfaction with call handling	76%	79%	80%
Satisfaction with ability to access	75%	78%	82%
Satisfaction with Interactive Voice Response (IVR)	67%	67%	71%
Representative able to give Estimated Time of Outage Restoration (ETR)	39%	57%	71%

Energy Probe Research Foundation (EP) INTERROGATORY #24 List 2

Interrogatory

Ref: Exh. C1/T 2/S 2, p. 22
Exh. C1/T 2/S 3, pp. 1, 4-5

Issue 3.1: Are the overall levels of the 2008 Operation, Maintenance and Administration budgets appropriate?

a) Has the Applicant developed or plan to develop a Farm Stray Voltage program featuring protocols on testing and measuring in 2008? If so, what are the details of the program? If not, why not?

b) Is the Applicant preparing for the expected OEB decision on Farm Stray Voltage in 2008, in terms of hiring personnel and re-considering protocols related to the Transmission Code?

Response

a) Hydro One has had standard protocols on testing, measuring, and mitigation since the mid-80's. These protocols have been continually updated to capture the latest measurement equipment and practices, as well as corrective equipment. Hydro One will continue to maintain these standard protocols in 2008. Training for Hydro One Field staff on updates to these protocols, which was initiated in 2007, will continue in 2008. In parallel with this, Hydro One will launch an internal Farm Stray Voltage tracking process, to ensure that relevant calls are tracked and dealt with by appropriately trained staff.

b) Hydro One actively participates in the OEB's Farm Stray Voltage Consultative Group work and is prepared to implement the recommendations to be produced by the Group, as they relate to the Distribution System Code.

Energy Probe Research Foundation (EP) INTERROGATORY #25 List 2

Interrogatory

Ref: Exh. C1/T 2/S 6, Attachment A
Issue 3.1: Are the overall levels of the 2008 Operation, Maintenance and Administration budgets appropriate?

How many Inergi or Vertex employees serving Hydro One are outsourced, i.e. how many "warm bodies" does Inergi and Vertex employ outside Canada and Ontario to serve the current Hydro One contract? What categories of Inergi and Vertex employees are outsourced outside of Canada and Ontario, if they have been outsourced? How long have these categories of employees been outsourced by Inergi and Vertex, if they have been outsourced?

Response

Inergi LP and Vertex Canada both report they do not currently have staff located outside of Ontario that are used in the delivery of Base Services to Hydro One Networks. The number and location of resources used by Inergi LP or Vertex Canada to deliver services to Hydro One is not relevant to the overall level of 2008 OM&A budgets given the terms of our outsourcing agreement for a fixed and declining price structure.

Energy Probe Research Foundation (EP) INTERROGATORY #26 List 2

Interrogatory

Ref: Exh. C1/T 2/S 6, Attachment A
Issue 3.1: Are the overall levels of the 2008 Operation, Maintenance and Administration budgets appropriate?

a) What kind of performance bond(s) does the Applicant sustain in its contract with Inergi? What are the details of this performance bond(s), if they exist?

b) Is Inergi and Vertex Canada currently ISO certified?

Response

a) There are no performance bond(s) in the contract with Inergi.

b) Inergi LP and Vertex Canada have indicated the following areas have been ISO certified:
   a. Vertex – Billing (CSO)
   b. Inergi – F&A
   c. Inergi – HR Payroll
   d. Inergi - Settlements

Energy Probe Research Foundation (EP) INTERROGATORY #27 List 2

Interrogatory

Ref: Exh. C1/T 3/S 1
Issue 3.6: Are the 2008 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate?

What succession planning initiatives is the Applicant undertaking to replace retiring top managers/executives over the next five years?

Response

In order to address pending retirements in senior positions, Hydro One has initiated a few programs. Succession planning for senior management staff (Direct reports to the CEO and their Direct Reports) involves identifying at least two successor candidates for each position and ensuring a developmental plan for each candidate is implemented. The Management Steering Committee has also developed an accelerated developmental pool comprised of individuals identified as high potential employees. These employees are assessed using an external developmental tool which is used to develop appropriate opportunities for more senior positions. Finally, a pilot project was initiated this year to identify talent at an earlier stage in an employee's career in order to target employees for accelerated opportunities in mid management and potentially more senior positions.

Energy Probe Research Foundation (EP) INTERROGATORY #28 List 2

Interrogatory

Ref: Exh. G1/T 2/S 3, p. 4, Table 4
Issue 7.1: Are Hydro One's proposed new Customer Rate Classes appropriate?

Please define in detail *existing* customer classes R3 and R4, i.e. provide precise descriptors for these two current classes.

Response

The two existing seasonal residential customer classes are defined in Exhibit G2, Tab 5, Schedule 2, page 3. The Density definitions are provided in the same Exhibit on page 2.

R3 is Seasonal occupancy in a high density zone and R4 is Seasonal occupancy in a Normal Density Zone. High Density Zones are areas containing 100 or more customers with a line density of at least 15 customers per kilometre. Normal Density zone is defined as areas other than Urban or High Density.

Energy Probe Research Foundation (EP) INTERROGATORY #29 List 2

Interrogatory

Ref: Exh. G1/T 2/S 5, p. 2
Exh. G1/T2/S 5, p.9
Issue 7.8: Are the customer bill impacts resulting from the proposed rate impact mitigation plan reasonable?

Please explain why the Applicant chooses a *four-year* phase-in approach for harmonization; why specifically four years?

Response

A four year phase-in approach will result in the target distribution rates being fully implemented in May 2011. The May 2011 time frame for harmonization was selected for the following reasons:

- Limits acquired customers' bill impacts to less than 10% of total bill per year based on average consumption;
- Is the expected end date for the Board's 3rd Generation IRM and would coincide with the establishment of rates based upon a new cost of service application; and
- Would coincide with the implementation of our new billing system and the anticipated date for full implementation of time-of-use rates.

Energy Probe Research Foundation (EP) INTERROGATORY #30 List 2

Interrogatory

Ref: Exh. G1/T 2/S 5, p. 2
Issue 7.7: Is the proposal for harmonization of rates appropriate?
Issue 7.8: Are the customer bill impacts resulting from the proposed rate impact mitigation plan reasonable?

a) Why did the Applicant choose to have an "average total yearly bill impact of less than *10 percen*t in its harmonization plan;" i.e. why was the 10 percent level chosen or arrived at for Acquired LDCs?

b) Did the Applicant anticipate that the plan would produce on average +/- 8-9 percent bill impact for Acquired LDCs? What was the methodology for this outcome?

c) Assuming +/- 8-9 percent is the average bill impact, what are the ranges of bill impacts for all existing customer classes?

Response

a. The ten percent bill impact is the bill impact included in the 2006 EDR guidelines established by the OEB.

b. It is not clear to Hydro One where the reference to +/- 8% to 9% is found in Exhibit G1, Tab 2, Schedule 5, page 2. In any case Hydro One did not anticipate that the plan would produce a +/- 8% to 9% bill impacts for Acquired LDC customers.

c. A +/- 8% to 9% impacts instead of a 10% impact limit, does not change the total bill impact to Acquired customers over the four year phase-in approach. It would only mean that Acquired customer bills that are between 8% or 9% to 10% for 2008, would now be limited to 8% to 9%. Legacy customers in the Residential and General Service rate classes where Acquired customers are being mapped to would have slightly higher bill impacts in 2008 than proposed to compensate for the lower revenues collected from Acquired customers.

Energy Probe Research Foundation (EP) INTERROGATORY #31 List 2

Interrogatory

Ref: Exh. G1/T 3/S 1, p. 5, Table 3
Exh. G1/T 5/S 1, p. 5, Table 1
Exh. G1/T 7/S 1, p. 6, Table 4

Issue 7.8: Are the customer bill impacts resulting from the proposed rate impact mitigation plan reasonable?

a) Please explain why the Applicant is placing such a significant bill impact burden on seasonal class customers (154,000 Ontario residents) compared to other proposed classes. Moreover, why is the Applicant placing such an extraordinary burden on the existing R3 customer class with a total bill impact of 23.3% for 2008 -- notwithstanding mitigation efforts?

b) Why are new seasonal class customers subsidizing every other new customer class except "street lighting and "sentinel lighting"?

Response

a. The total bill impact for Seasonal customers is not 23.3% in 2008.

As shown in Exhibit G1, Tab 8, Schedule 1, page 4, Table 2, the impact to seasonal customers for 2008 ranges between 7% and 9.8% of total bill, based on average consumption. At the end of the 4 year phase-in approach, the total bill impact for R3 customers is 21.3% and for R4 customers is a bill reduction of 0.1%, as shown in Exhibit G1, Tab 7, Schedule 1, page 6, Table 4. The bill impact to R3 customers is less than the bill impact that some Acquired customers would see. The proposed Seasonal customer class is composed of 70,750 R3 customers, 84,477 R4 customers and 210 Caledon customers, as shown in Exhibit G1, Tab 2, Schedule 3, page 4, Table 4.

Hydro One is proposing to reduce the number of customer classes and combining the two existing seasonal customer classes into one class results in the impacts to R3 customers mentioned above.

b. The new Seasonal customer class is not subsidizing any other customer class. The proposed revenue to cost ratio for this class is 1, as shown in Exhibit G1, Tab 3, Schedule 1, page 4, Table 2.

Energy Probe Research Foundation (EP) INTERROGATORY #32 List 2

Interrogatory

Ref: Exh. C1/T 2/S 2, pp. 26-28
Exh. C1/T 2/S 5, p. 10
Issue 8.1: Is the smart meter O&M budget appropriate?

a) How many smart meters did the Applicant install in the period up to Dec. 31, 2007?

b) Has the applicant undertaken a cost-benefit analysis of its smart meter program since installations began? If so, please report the results of this cost-benefit analysis. If (a) cost-benefit analysis(es) has/have not been undertaken, why not?

c) What obstacles, if any, exist to prevent the undertaking of a cost-benefit analysis of the Applicant's smart meter program? Does the Applicant plan to undertake a cost-benefit analysis if none has been undertaken?

Response

a) Hydro One installed 222,831 smart meters in 2007 for a cumulative total to the end of 2007 of 250,431.

b) A high level cost benefit analysis was undertaken at the beginning of the smart meter program (2005) and was used as the basis of determining system (IT) and communications architecture. The analysis concluded that given Hydro One's demographics, geography and business needs, it should procure and install a system capable of being migrated to a more ubiquitous communications network supporting applications beyond just smart meters (such as two-way communications for CDM devices in the home, distribution SCADA and real-time outage management, and potentially new initiatives like distributed generation).

Once the architectural decisions were made Hydro One focused on designing and installing a smart meter system capable of migrating or evolving to higher levels of functionality but at the same time allowed the team to focus on the near term goal of meeting the specification per the regulations. Benefits within Hydro One's

business have also been identified as directly related to smart meters. These are described in Exhibit C1 Tab 2 Schedule 2.

c) There are no specific obstacles however the focus now is on meeting the government directive. Future applications will be developed on a more stand alone case by case basis supported by individual business cases.

Rogers Cable INTERROGATORY #1 List 1

Interrogatory

[Reference: Exhibit Gl, Tab 2, Schedule 3, page 6, Table 7] Of the 4,917 Unmetered Scattered Load connections, please provide a table showing how many connections are in *each* acquired LDC, in the Legacy G1 class, the Legacy G3 class and the Legacy UG class. In a column of this table, please provide the total kWh of estimated consumption for USL in each of these LDCs and rate classifications, as forecast for the test year and as billed for 2007.

Response

Table 1 below is a listing of 4917 Unmetered Accounts by rate class and 2006 billed consumption. Table 2 below lists the further delineation by Acquired Distributor.

Billing data for 2007 is not yet available.

Forecast factors of 0.5% and 0.6% can be applied to the 2006 customer number and billed kWhs respectively to get forecast 2008 levels.

Table 1: USL Class Decomposition

Class	Number	2006 kWhs
G1	3624	18,012,264
G3	14	233,151
UG	392	2,637,231
Acquireds	887	5,748,227
	4917	26,630,872

Table 2

Acquired LDC	Number	2006 kWhs
Ailsa Craig	2	15,662
Arkona	2	12,141
Arnprior	23	174,938
Artemesia	8	35,508
Avonmore	2	14,988
Bancroft	5	37,318
Bath	2	9,147
Blandford-Blenheim	11	51,980
Bobcaygeon	18	90,009
Brechin	2	6,077
Brighton Town	3	27,506

Acquired LDC	Number	2006 kWhs
Brockville	39	741,071
Caledon	85	499,890
Campbellford	12	61,468
Carleton Place	31	365,097
Chalk River	2	12,690
Champlain Twp	10	34,199
Chatsworth	1	866
Chesley	5	15,177
Cobden	8	17,850
Coldwater	8	45,457
Deep River	2	5,453
Delaware Village	3	18,942
Deseronto	3	9,741
Dorchester Town	1	6,466
Dryden	4	16,860
Dundalk	2	10,514
Durham	6	27,761
Eganville	4	10,707
Elmvale	5	41,771
Erin	21	131,699
Exeter	19	80,525
Fenelon Falls	10	49,793
Finch	6	31,526
Forest	7	52,853
Glencoe	1	4,539
Grand Bend	1	6,458
Granton	1	754
Hastings	10	40,434
Havelock	3	10,776
Kemptville	8	26,073
Lanark	3	16,241
Larder Lake	1	602
Lindsay	71	378,550
Listowel	11	55,947
Lucan	4	7,508
Madoc Village	2	1,299
Marmora	10	46,498
Meaford	23	154,641
Millbrook	3	20,933
Milverton	3	15,582
Napanee	13	54,697
Nipigon Town	3	11,733
North Dundas	12	50,623
North Glengarry	6	31,542
Omemee	5	21,873
Owen Sound	47	253,490
Paisley	2	1,347

Acquired LDC	Number	2006 kWhs
Perth	26	83,970
Prince Edward County	20	90,442
Quinte West	32	162,294
Red Rock	3	26,168
Rockland Town	18	102,309
Russell	7	23,408
Schreiber	5	31,043
Shelburne	8	39,749
Smiths Falls	15	134,542
South Glengarry	1	4,574
South River	1	361
Springfield	1	4,543
Stirling Village	3	13,734
Stouffville	21	108,578
Sutton	9	62,058
Tara	1	5,257
Thedford	3	19,205
Thorndale	3	25,827
Thorold	71	601,207
Tweed	8	51,888
Virginiatown	2	5,787
Wardsville	2	6,598
West Elgin	4	15,053
Wiarton	4	11,962
Woodville	1	662
Wyoming	3	141,221
Total	887	5,748,227

Rogers Cable INTERROGATORY #2 List 1

Interrogatory

[Reference: Exhibit Gl, Tab 2, Schedule 3, page 6, Table 7]

(a) Please explain the rationale for grouping all Unmetered Scattered Load (USL) customers with the low density General Service Energy Billed customers, regardless oftheir location (i.e. in high or low density areas).

(b) Please indicate how many of the 4,917 USL customers proposed to be included in the General Service Energy Billed class are actually located in areas in which customers meet the Urban Density Criteria. For the identified USL customers, please provide estimated aggregate consumption for the test year and as billed consumption for 2007.

(c) Please provide a table that compares the rate that would be payable by a USL customer were they to be included in the Urban General Service Energy Billed class (i.e. classified with customers meeting the Urban Density Criteria) with the rate proposed for USL customers under the proposed General Service Energy Billed class.

Response

Ref: G1-2-3 pg 6 Table 7

a. Currently three-quarters of the Unmetered Scattered Load [USL] customers are located within the G1 rate class and another 10% from the non-urban mapped Acquireds for a total of 85% being non-urban general service.

   Since about 85% of the USL customers are currently located within the non-urban General Service, the new USL class was composed by grouping all USL customers to the non-urban General Service rate class.

b. 392 of the 4,917 USL are in Urban Density class. Based on 2006 billing data, the billed amount was 2.64 GWh

c. A full model re-run with new rate classes based on these remapped customers would need to be done and cannot be accomplished within the Interrogatory response timelines. Please see Exhibit H, Tab 4, Schedule 10 for the effort required to create a new customer class and run the cost allocation model. The USL load is minimal compared to the load in the Urban General Service energy class, so the results are not expected to be different for the Urban General Service

energy class including or excluding the USL load that might be classified as Urban.

The USL Meter Credit from the Cost Model Output sheet O3.5 USL Metering Credit for Urban General Service energy billed class is $6.65 and is comparable to the GSe USL Metering credit of $6.86.

The Table below shows the rates for USL in the General Service energy bill class and in the Urban General Service energy bill class.

	O3.5 USL Credit	Service Charge	Net Service Chg	Base ¢/kWh
GSe	$6.86	$30.97	$24.11	3.39
UGe	$6.65	$12.33	$5.68	2.09

Rogers Cable INTERROGATORY #3 List 1

Interrogatory

[Reference: Exhibit Gl, Tab 2, Schedule 3, page 6, Table 7] For the proposed General Service Energy Billed customers as a class, and for each of the subclasses listed in Table 7, please provide the annual load factor.

Response

Table 7 of Exhibit G1, Tab 2, Schedule 3, page 6, shows the number of customers that are being mapped to the new General Service energy billed class broken down by current customer class. These are not sub classes of the new General Service energy billed class. The number of customers shown are a sub-set of the customers in the current customer classes. Load Factors as requested are shown in the Table below.

Current Customer Class	Load Factor
General Service single-phase energy billed	0.502
General Service three-phase energy billed	0.617
T-Class customers energy billed	0.551
Farm single phase energy billed and no RRRP	0.424
Farm three phase energy billed and no RRRP	0.652
Acquired LDCs General Service customers energy billed	0.660
Unmetered Scattered Load	0.654
Total Proposed General Service Energy Billed	**0.548**

Rogers Cable INTERROGATORY #4 List 1

Interrogatory

[Reference: Exhibit Gl, Tab 2, Schedule 3]

(a) Please explain the rationale for maintaining a separate rate class for each of Street Lighting and Sentinel Lighting, while continuing to group Unmetered Scattered Load facilities within a more diverse general service class. In the response please include comment regarding any applicable technical difference between these 3 types of load and the relevance of these differences to the determination of when a separate rate class is and is not appropriate.

(b) Please provide a table that compares the rate that would be payable by a USL customer were they to be included in the Street Lighting class or the Sentinel Lighting class (i.e. one column for each of these classes) with the rate proposed for USL customers under the proposed General Service Energy Billed class. Please include any additional explanation relevant to the probative value of this table.

Response

a. Street Lights and Sentinel Lights have always been separate Rate Classes while the Unmetered Scattered Load has been a sub-class of General Service.

Hydro One Distribution's proposal is to maintain this delineation.

The main technical difference between the Lighting accounts and USL accounts is the more accurate kWh estimate possible for lighting compared to USL. That is, lamp wattage plus ballast and hours of usage. While, there are more diverse technical considerations for the varied USL type of loads like amplifier heating blankets.

b. A full cost allocation model re-run with new rate classes based on these remapped customers would need to be done and cannot be accomplished within the Interrogatory response timelines. Please see Exhibit H, Tab 4, Schedule 10, for an explanation of the effort required to create a new customer class and run the cost allocation model.

Rogers Cable INTERROGATORY #5 List 1

Interrogatory

[Reference: Exhibit Gl, Tab 3, Schedule 1, page 2, Table 1]

(a) Has Hydro One conducted a "Run 2" of the cost allocation study in order to separate Unmetered Scattered Load from the General Service Energy Billed class and compute a separate revenue/cost ratio for USL customers? If so, please provide:
   (i) A table showing the revenue/cost ratios for Unmetered Scattered Load for the legacy customers and each acquired LDC.
   (ii) A printed copy of table 01 from each study.
   (iii) The electronic version of each study.

(b) If no "Run 2" was made using test year data, please provide any studies prepared based on the test year for 2006 rates.

(c) If no "Run 2" has been done for the current or 2006 test year, please perform the analysis on the same year of data used to produce the referenced Table 1, and provide the results in electronic form.

(d) Please explain the nature of any fees charged to, or costs recovered from, Unmetered Scattered Load customers which are not part of the approved rate schedules. Please provide the amounts of each such fee or cost and the total amount of revenue or cost involved. Please explain whether or not any such fees or costs recovered are taken into account in computing the revenue/cost ratio for Unmetered Scattered Load in the Run 2 cost allocation studies, and if not, why not.

Response

a. No, Hydro One Distribution has not done a “Run 2” with a separate Unmetered Scattered Load Class.

b. Please see attached information. This information is from “Run 2” of the Cost Allocation Information Filing using 2006 approved Revenue Requirement data and filed as part of Proceeding RP-2005-0317/EB-2007-0001.

c. A full model re-run with new rate classes based on these remapped customers would need to be done. See Exhibit H, Tab 4, Schedule 10, concerning effort needed to re-run the Cost Allocation Model using different customer classes.

d. There are no other fees or charges above those of the Approved Rate Schedules.

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2006 Cost Allocation Information Filing
Input Sheet for Selection of Classes, Demand Allocators and Specific Allocators

Run 2: Hydro One Distribution with Customer Class Density Weights

Instructions
Step 1 - Please input your existing classes
Step 2 - If this is your first run, select "First Run" in the drop down menu below
Step 3 - After all classes have been entered, Click the "Update" in cell E41.

If this is your first run, select "**First Run**" and click on the "**Update**" button.
Note: You must always do a first run with current selected.

Second Run

		Utility's Class Definition	Current
1	Residential	UR	YES
2	GS <50	R1	YES
3	GS>50-Regular	R2	YES
4	GS> 50-TOU	R3	YES
5	GS >50-Intermediate	R4	YES
6	Large Use >5MW	F1	YES
7	Street Light	F3	YES
8	Sentinel	UG	YES
9	Unmetered Scattered Load	G1	YES
10	Embedded Distributor	G3	YES
11	Back-up/Standby Power	T	YES
12	Rate Class 1	St Lgts	YES
13	Rate class 2	Sentinel Lgts	YES
14	Rate class 3	AcqRes	YES
15	Rate class 4	AcqGS<50	YES
16	Rate class 5	AcqGS>50	YES
17	Rate class 6	AcqLU	YES
18	Rate class 7	LV-Dir+LDC	YES
19	Rate class 8	USL	YES
20	Rate class 9	Standby	YES

After you have set all rate classes

Update

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Input Sheet for the Break Out Of Distribution Assets, Contributed Capital and Amortization and Amortization Expenses

Run 2: Hydro One Distribution with Customer Class Density Weights

See Handbook for Detail Instructions

Enter Net Fixed Assets from RP-2005-0020/EB-2005-0378 Exhibit D2, Tab 1, Sch 1	$ 3,423,300,000

BALANCE SHEET ITEMS

RATE BASE AND DISTRIBUTION ASSETS

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995
1565	Conservation and Demand Management	$0		-	-	$0
1805	Land	$84,913,408		($84,913,408)	-	($443,644)
1805-1	Land Station >50 kV		10.00%	$8,491,341	8,491,341	($44,364)
1805-2	Land Station <50 kV		90.00%	$76,422,068	76,422,068	($399,280)
1806	Land Rights	$239,633,171		($239,633,171)	-	($8,619,349)
1806-1	Land Rights Station >50 kV		10.00%	$23,963,317	23,963,317	($861,935)
1806-2	Land Rights Station <50 kV		90.00%	$215,669,854	215,669,854	($7,757,414)
1808	Buildings and Fixtures	$5,131,269		($5,131,269)	-	($80,210)
1808-1	Buildings and Fixtures > 50 kV		50.00%	$2,565,634	2,565,634	($40,105)
1808-2	Buildings and Fixtures < 50 KV		50.00%	$2,565,634	2,565,634	($40,105)
1810	Leasehold Improvements	$0		$0	-	
1810-1	Leasehold Improvements >50 kV		50.00%	$0	-	$0
1810-2	Leasehold Improvements <50 kV		50.00%	$0	-	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	$93,816,160		($93,816,160)	-	($3,344,188)
1815-1	HVDS - Rural		87.3%	$81,908,019	81,908,019	($2,919,708)
1815-2	HVDS - lo LV Specific		0.6%	$582,467	582,467	($20,763)
1815-3	HVDS - hi LV Specific		2.1%	$1,944,058	1,944,058	($69,298)
1815-4	HVDS - lo LV Shared		5.0%	$4,690,808	4,690,808	($167,209)
1815-5	HVDS - hi LV Shared		5.0%	$4,690,808	4,690,808	($167,209)
1820	Distribution Station Equipment - Normally Primary below 50 kV	$248,721,283		($248,721,283)	-	($674,337)
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		0.00%	$0	-	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)		95.30%	$237,031,383	237,031,383	($674,337)
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		4.70%	$11,689,900	11,689,900	
1825	Storage Battery Equipment	$0		$0	-	
1825-1	Storage Battery Equipment > 50 kV		50.00%	$0	-	
1825-2	Storage Battery Equipment <50 kV		50.00%	$0	-	
1830	Poles, Towers and Fixtures	$1,743,551,306		($1,743,551,306)	-	($121,681,852)
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		15.00%	$261,532,696		($18,252,278)
1830-3A	Bulk-LV Fixtures		3.08%	$8,055,207	8,055,207	($562,170)
1830-3B	Bulk-Retail Fixtures		96.92%	$253,477,489	253,477,489	($17,690,108)
1830-4	Poles, Towers and Fixtures - Primary		70.00%	$1,220,485,914		($85,177,297)
1830-4A	Primary-LV Fixtures		0.81%	$9,885,936	9,885,936	($689,936)
1830-4B	Primary-Retail Fixtures		99.19%	$1,210,599,978	1,210,599,978	($84,487,361)
1830-5	Poles, Towers and Fixtures - Secondary		15.00%	$261,532,696	261,532,696	($18,252,278)
1835	Overhead Conductors and Devices	$1,149,104,830		($1,149,104,830)	-	($63,441,072)
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		15.00%	$172,365,725		($9,516,161)
1835-3A	Bulk-LV Conductors		3.08%	$5,308,864	5,308,864	($293,098)
1835-3B	Bulk-Retail Conductors		96.92%	$167,056,860	167,056,860	($9,223,063)
1835-4	Overhead Conductors and Devices - Primary		70.00%	$804,373,381		($44,408,751)
1835-4A	Primary-LV Conductors		0.81%	$6,515,424	6,515,424	($359,711)
1835-4B	Primary-Retail Conductors		99.19%	$797,857,957	797,857,957	($44,049,040)
1835-5	Overhead Conductors and Devices - Secondary		15.00%	$172,365,725	172,365,725	($9,516,161)
1840	Underground Conduit	$25,532,863		($25,532,863)	-	($1,089,200)
1840-3	Underground Conduit - Bulk Delivery			$0	-	$0
1840-4	Underground Conduit - Primary		20.00%	$5,106,573	5,106,573	($217,840)
1840-5	Underground Conduit - Secondary		80.00%	$20,426,290	20,426,290	($871,360)
1845	Underground Conductors and Devices	$207,660,508		($207,660,508)	-	($117,571,722)

Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Contributed Capital - 1995
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-	$0
1845-4	Underground Conductors and Devices - Primary		20.00%	$41,532,102	41,532,102	($23,514,344)
1845-5	Underground Conductors and Devices - Secondary		80.00%	$166,128,406	166,128,406	($94,057,377)
1850	Line Transformers	$1,501,163,815		($1,501,163,815)	-	($81,138,082)
1850-1	TRF-LV		0.3%	$4,503,491	4,503,491	($243,414)
1850-2	TRF-Rural		99.7%	$1,496,660,324	1,496,660,324	($80,894,668)
1855	Services	$0		$0	-	
1860	Meters	$86,581,415		($86,581,415)	-	($4,411,296)
1860-1	Mtr-Single		64%	$55,134,535	55,134,535	($2,809,088)
1860-2	Mtr-Poly		33%	$28,250,878	28,250,878	($1,439,374)
1860-3	Mtr-LV		4%	$3,196,002	3,196,002	($162,835)
1860-4	Mtr-Smart		0%	$0	-	$0
1875	St Lgts+Signal Systems				-	
modified	Total	$5,385,810,029	**$5,385,810,029**	**from O1**	5,385,810,029	- 402,494,952
	I3 sub total	$5,385,810,029	**$5,385,810,029**	**excl 1875**		

General Plant		Break out Functions				Contributed Capital - 1995
1905	Land	$3,471,906			3,471,906	($1)
1906	Land Rights	$0			-	
1908	Buildings and Fixtures	$94,310,045			94,310,045	($124,323)
1910	Leasehold Improvements	$7,004,105			7,004,105	($0)
1915	Office Furniture and Equipment	$5,249,271			5,249,271	$0
1920	Computer Equipment - Hardware	$45,642,883			45,642,883	($6,399)
1925	Computer Software	$139,379,309			139,379,309	($2,133)
1930	Transportation Equipment	$120,444,271			120,444,271	$0
1935	Stores Equipment	$15,897,272			15,897,272	$0
1940	Tools, Shop and Garage Equipment	$3,185,723			3,185,723	$0
1945	Measurement and Testing Equipment	$3,285,019			3,285,019	$0
1950	Power Operated Equipment	$68,159,581			68,159,581	$0
1955	Communication Equipment	$20,810,405			20,810,405	($83,530)
1960	Miscellaneous Equipment	$2,096,368			2,096,368	$0
1970	Load Management Controls - Customer Premises	$0			-	
1975	Load Management Controls - Utility Premises	$0			-	
1980	System Supervisory Equipment	$16,906,150			16,906,150	($475,363)
1985	Sentinel Lgts	$16,153,422			16,153,422	($301,371)
1990	Other Tangible Property	$5,682,312			5,682,312	$0
2005	Property Under Capital Leases	$0			-	
2010	Electric Plant Purchased or Sold	$0			-	
	Total	$567,678,044			$567,678,044	($993,121)
	I3 Sub total	$567,678,044		**$567,678,044**	**$567,678,044**	
	I3 Directly Allocated	$0		**from O1**	**check**	
	Grand Total	$5,953,488,073			$5,953,488,073	($403,488,073)

To be Prorated

1995	Contributed Capital - 1995	($403,488,073)		$403,488,073
2105	Accumulated Depreciation - 2105	($2,126,700,000)		
2120	Accumulated Depreciation - 2120	$0		
	Total	($2,530,188,073)		
	Net Assets	$3,423,300,000.0	**Net Fixed Assets Match EDR**	

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	$169,900,000
5710	Amortization of Limited Term Electric Plant	$0
5715	Amortization of Intangibles and Other Electric Plant	$0
5720	Amortization of Electric Plant Acquisition Adjustments	$0
	Total Amortization Expense	$169,900,000

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Input Sheet for the Break Out Of Distribution Assets, C

See Handbook for Detail Instructions

Enter Net Fixed Assets from RP-2005-0020/EB-2005-0378 Exhibit D2, Tab 1, Sch 1

						EXPENSE ITEMS
RATE BASE AND DISTRIBUTION ASSETS						5705
Account	Description	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Acc Dep and Cont Cap	Amortization Expense - Property, Plant, and Equipment
1565	Conservation and Demand Management	$0	$0		-	$0
1805	Land	($132,567)	($34,506,337)			$191
1805-1	Land Station >50 kV	($13,257)	($3,450,634)		4,983,086	$19
1805-2	Land Station <50 kV	($119,310)	($31,055,703)		44,847,775	$172
1806	Land Rights	($2,023,568)	($58,965,710)			$0
1806-1	Land Rights Station >50 kV	($202,357)	($5,896,571)		17,002,454	$0
1806-2	Land Rights Station <50 kV	($1,821,211)	($53,069,139)		153,022,089	$0
1808	Buildings and Fixtures	($31,474)	($3,351,121)			$3,673,053
1808-1	Buildings and Fixtures > 50 kV	($15,737)	($1,675,561)		834,232	$1,836,526
1808-2	Buildings and Fixtures < 50 KV	($15,737)	($1,675,561)		834,232	$1,836,526
1810	Leasehold Improvements					
1810-1	Leasehold Improvements >50 kV	$0	$0		-	$0
1810-2	Leasehold Improvements <50 kV	$0	$0		-	$0
1815	Transformer Station Equipment - Normally Primary above 50 kV	($1,185,975)	($28,373,691)		- 32,903,854	$1,995,613
1815-1	HVDS - Rural	($1,035,438)	($24,810,318)		53,142,554	$1,742,309
1815-2	HVDS - lo LV Specific	($7,363)	**($222,075)**		332,266	$12,390
1815-3	HVDS - hi LV Specific	($24,576)	**($503,929)**		1,346,255	$41,353
1815-4	HVDS - lo LV Shared	($59,299)	($1,418,685)		3,045,615	$99,781
1815-5	HVDS - hi LV Shared	($59,299)	($1,418,685)		3,045,615	$99,781
1820	Distribution Station Equipment - Normally Primary below 50 kV	($284,912)	($105,076,035)		- 106,035,284	$4,855,163
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	$0	$0		-	$0
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)	($284,912)	($104,076,035)		131,996,099	$4,855,163
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		$ (1,000,000)		10,689,900	$1,268,552
1825	Storage Battery Equipment					
1825-1	Storage Battery Equipment > 50 kV				-	
1825-2	Storage Battery Equipment <50 kV				-	
1830	Poles, Towers and Fixtures	($28,283,928)	($569,792,475)			$73,124,321
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	($4,242,589)	($85,468,871)		- 107,963,738	$10,968,648
1830-3A	Bulk-LV Fixtures	($130,672)	($2,632,441)		4,729,924	$337,834
1830-3B	Bulk-Retail Fixtures	($4,111,918)	($82,836,430)		148,839,034	$10,630,814
1830-4	Poles, Towers and Fixtures - Primary	($19,798,750)	($398,854,733)		- 503,830,779	$51,187,025
1830-4A	Primary-LV Fixtures	($160,370)	($3,230,723)		5,804,907	$414,615
1830-4B	Primary-Retail Fixtures	($19,638,380)	($395,624,009)		710,850,229	$50,772,410
1830-5	Poles, Towers and Fixtures - Secondary	($4,242,589)	($85,468,871)		153,568,958	$10,968,648
1835	Overhead Conductors and Devices	($13,337,829)	($376,385,360)		- 453,164,261	$6,499,301
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	($2,000,674)	($56,457,804)		- 67,974,639	$974,895
1835-3A	Bulk-LV Conductors	($61,621)	($1,738,900)		3,215,245	$30,027
1835-3B	Bulk-Retail Conductors	($1,939,054)	($54,718,904)		101,175,840	$944,868
1835-4	Overhead Conductors and Devices - Primary	($9,336,480)	($263,469,752)		- 317,214,982	$4,549,511
1835-4A	Primary-LV Conductors	($75,625)	($2,134,105)		3,945,983	$36,851
1835-4B	Primary-Retail Conductors	($9,260,855)	($261,335,647)		483,212,416	$4,512,660
1835-5	Overhead Conductors and Devices - Secondary	($2,000,674)	($56,457,804)		104,391,085	$974,895
1840	Underground Conduit	($457,248)	($8,022,561)		- 9,569,010	$28,724
1840-3	Underground Conduit - Bulk Delivery	$0	$0		-	$0
1840-4	Underground Conduit - Primary	($91,450)	($1,604,512)		3,192,771	$5,745
1840-5	Underground Conduit - Secondary	($365,799)	($6,418,049)		12,771,082	$22,979
1845	Underground Conductors and Devices	($43,539,416)	$4,604,546		- 156,506,591	$1,291,406

Account	Description	Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Asset net of Acc Dep and Cont Cap	Amortization Expense - Property, Plant, and Equipment
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0		-	$0
1845-4	Underground Conductors and Devices - Primary	($8,707,883)	$920,909		10,230,783	$258,281
1845-5	Underground Conductors and Devices - Secondary	($34,831,532)	$3,683,637		40,923,133	$1,033,125
1850	Line Transformers	($12,113,587)	($418,176,056)		- 511,427,725	$46,368,765
1850-1	TRF-LV	($36,341)	($1,254,528)		2,969,208	$139,106
1850-2	TRF-Rural	($12,077,246)	($416,921,528)		986,766,881	$46,229,659
1855	Services				-	
1860	Meters	($2,524,024)	($74,487,706)		- 81,423,027	$7,151,566
1860-1	Mtr-Single	($1,607,284)	($47,433,332)		3,284,832	$4,554,075
1860-2	Mtr-Poly	($823,571)	($24,304,790)		1,683,144	$2,333,503
1860-3	Mtr-LV	($93,170)	($2,749,584)		190,413	$263,988
1860-4	Mtr-Smart	$0	$0		-	$0
1875	St Lgts+Signal Systems					
modified	Total	- 103,914,529	- 1,672,532,507	$0	3,206,868,041	146,256,656
	I3 sub total					

General Plant		Accumulated Depreciation - 2105 Capital Contribution	Accumulated Depreciation - 2105 Fixed Assets Only	Accumulated Depreciation - 2120	Net Asset	5705 Amortization Expense - Property, Plant, and Equipment
1905	Land	$0	($22,951)		$ 3,448,954	$0
1906	Land Rights				$ -	
1908	Buildings and Fixtures	($18,916)	($40,072,277)		$ 54,094,529	$1,502,629
1910	Leasehold Improvements	($0)	($3,456,292)		$ 3,547,813	$141,482
1915	Office Furniture and Equipment	$0	($5,128,240)		$ 121,031	$472,516
1920	Computer Equipment - Hardware	($2,088)	($40,814,494)		$ 4,819,902	$6,104,713
1925	Computer Software	($747)	($100,295,023)		$ 39,081,406	$8,173,971
1930	Transportation Equipment	$0	($48,301,398)		$ 72,142,873	$3,051,908
1935	Stores Equipment	$0	($20,389,340)		-$ 4,492,068	$812,747
1940	Tools, Shop and Garage Equipment	$0	($3,536,750)		-$ 351,027	$130,848
1945	Measurement and Testing Equipment	$0	($1,795,119)		$ 1,489,900	$594,327
1950	Power Operated Equipment	$0	($52,104,026)		$ 16,055,555	$0
1955	Communication Equipment	($16,375)	($16,453,068)		$ 4,257,432	$933,029
1960	Miscellaneous Equipment	$0	($1,318,888)		$ 777,480	$693,630
1970	Load Management Controls - Customer Premises				$ -	
1975	Load Management Controls - Utility Premises				$ -	
1980	System Supervisory Equipment	($107,724)	($3,564,179)		$ 12,758,884	$926,557
1985	Sentinel Lgts	($151,782)	($9,744,193)			$104,987
1990	Other Tangible Property	$0	($2,959,095)		$ 2,723,217	$0
2005	Property Under Capital Leases				$ -	
2010	Electric Plant Purchased or Sold				$ -	
	Total	($297,631)	($349,955,334)	$0	$210,475,883	$23,643,344
	I3 Sub total					
	I3 Directly Allocated					
	Grand Total	($104,212,160)	($2,022,487,840)	$0	$3,417,343,924	$169,900,000.00

To be Prorated

1995	Contributed Capital - 1995	**Balanced**			
2105	Accumulated Depreciation - 2105		$2,126,700,000	**Balanced**	
2120	Accumulated Depreciation - 2120			$0	**Balanced**
	Total				

Net Assets

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	($169,900,000)
5710	Amortization of Limited Term Electric Plant	
5715	Amortization of Intangibles and Other Electric Plant	
5720	Amortization of Electric Plant Acquisition Adjustments	

Total Amortization Expense

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Input Sheet for the Break Out Of Distribution Assets, C

See Handbook for Detail Instructions

Enter Net Fixed Assets from RP-2005-0020/EB-2005-0378 Exhibit D2, Tab 1, Sch 1

RATE BASE AND DISTRIBUTION ASSETS		5710	5715	5720
Account	Description	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1565	Conservation and Demand Management			
1805	Land			
1805-1	Land Station >50 kV			
1805-2	Land Station <50 kV			
1806	Land Rights			
1806-1	Land Rights Station >50 kV			
1806-2	Land Rights Station <50 kV			
1808	Buildings and Fixtures			
1808-1	Buildings and Fixtures > 50 kV			
1808-2	Buildings and Fixtures < 50 KV			
1810	Leasehold Improvements			
1810-1	Leasehold Improvements >50 kV			
1810-2	Leasehold Improvements <50 kV			
1815	Transformer Station Equipment - Normally Primary above 50 kV			
1815-1	HVDS - Rural			
1815-2	HVDS - lo LV Specific			
1815-3	HVDS - hi LV Specific			
1815-4	HVDS - lo LV Shared			
1815-5	HVDS - hi LV Shared			
1820	Distribution Station Equipment - Normally Primary below 50 kV			
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)			
1820-2	Distribution Station Equipment - Normally Primary below 50 kV Primary)			
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)			
1825	Storage Battery Equipment			
1825-1	Storage Battery Equipment > 50 kV			
1825-2	Storage Battery Equipment <50 kV			
1830	Poles, Towers and Fixtures			
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery			
1830-3A	Bulk-LV Fixtures			
1830-3B	Bulk-Retail Fixtures			
1830-4	Poles, Towers and Fixtures - Primary			
1830-4A	Primary-LV Fixtures			
1830-4B	Primary-Retail Fixtures			
1830-5	Poles, Towers and Fixtures - Secondary			
1835	Overhead Conductors and Devices			
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery			
1835-3A	Bulk-LV Conductors			
1835-3B	Bulk-Retail Conductors			
1835-4	Overhead Conductors and Devices - Primary			
1835-4A	Primary-LV Conductors			
1835-4B	Primary-Retail Conductors			
1835-5	Overhead Conductors and Devices - Secondary			
1840	Underground Conduit			
1840-3	Underground Conduit - Bulk Delivery			
1840-4	Underground Conduit - Primary			
1840-5	Underground Conduit - Secondary			
1845	Underground Conductors and Devices			

Account	Description	Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1845-3	Underground Conductors and Devices - Bulk Delivery			
1845-4	Underground Conductors and Devices - Primary			
1845-5	Underground Conductors and Devices - Secondary			
1850	Line Transformers			
1850-1	TRF-LV			
1850-2	TRF-Rural			
1855	Services			
1860	Meters			
1860-1	Mtr-Single			
1860-2	Mtr-Poly			
1860-3	Mtr-LV			
1860-4	Mtr-Smart			
1875	St Lgts+Signal Systems			
modified	Total	$0	$0	$0
	I3 sub total			

		5710	5715	5720
General Plant		Amortization of Limited Term Electric Plant	Amortization of Intangibles and Other Electric Plant	Amortization of Electric Plant Acquisition Adjustments
1905	Land			
1906	Land Rights			
1908	Buildings and Fixtures			
1910	Leasehold Improvements			
1915	Office Furniture and Equipment			
1920	Computer Equipment - Hardware			
1925	Computer Software			
1930	Transportation Equipment			
1935	Stores Equipment			
1940	Tools, Shop and Garage Equipment			
1945	Measurement and Testing Equipment			
1950	Power Operated Equipment			
1955	Communication Equipment			
1960	Miscellaneous Equipment			
1970	Load Management Controls - Customer Premises			
1975	Load Management Controls - Utility Premises			
1980	System Supervisory Equipment			
1985	Sentinel Lgts			
1990	Other Tangible Property			
2005	Property Under Capital Leases			
2010	Electric Plant Purchased or Sold			
	Total	$0	$0	$0
	I3 Sub total			
	I3 Directly Allocated			
	Grand Total	$0	$0	$0

To be Prorated

1995	Contributed Capital - 1995
2105	Accumulated Depreciation - 2105
2120	Accumulated Depreciation - 2120

Total

Net Assets

Amortization Expenses

5705	Amortization Expense - Property, Plant, and Equipment	**Balanced**			
5710	Amortization of Limited Term Electric Plant	$0	**Balanced**		
5715	Amortization of Intangibles and Other Electric Plant		$0	**Balanced**	
5720	Amortization of Electric Plant Acquisition Adjustments			$0	**Balanced**

Total Amortization Expense

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Output Sheet Showing Revenue to Cost Summary by Major Groupings by Class

Run 2: Hydro One Distribution with Customer Class Density Weights

Class Revenue and Cost Analysis and Return on Rate Base

Rate Base Assets		Total	1 UR	2 R1	3 R2	4 R3	5 R4	6 F1
crev	Distribution Revenue (sale)	$925,000,000	$27,100,000	$153,560,000	$259,790,000	$24,850,000	$42,070,000	$107,910,000
mi	Miscellaneous Revenue (mi) -- ***allocated by CWNB+LPHA***	$40,200,000	$2,444,565	$9,837,705	$9,524,275	$882,418	$1,102,654	$3,163,823
	Total Revenue	$965,200,000	$29,544,565	$163,397,705	$269,314,275	$25,732,418	$43,172,654	$111,073,823
	Expenses							
di	Distribution Costs (di)	$234,372,509	$3,389,164	$59,550,579	$99,645,128	$4,002,438	$7,190,257	$22,116,250
cu	Customer Related Costs (cu)	$109,295,585	$6,365,130	$26,344,583	$29,333,295	$2,938,332	$3,950,699	$9,674,039
ad	General and Administration (ad)	$103,626,754	$2,881,856	$26,034,929	$39,027,289	$2,065,411	$3,323,968	$9,558,898
dep	Depreciation and Amortization (dep)	$169,900,000	$2,918,423	$46,163,706	$67,670,026	$2,667,053	$4,544,219	$14,722,962
INPUT	PILs (INPUT)	$79,800,000	$1,402,331	$21,847,908	$31,911,303	$1,206,494	$2,069,719	$7,039,066
INT	Interest	$132,200,000	$2,323,160	$36,194,154	$52,865,592	$1,998,728	$3,428,782	$11,661,210
	Total Expenses	$829,194,849	$19,280,062	$216,135,859	$320,452,632	$14,878,457	$24,507,643	$74,772,426
	Direct Allocation	$7,605,151	$14,190	$124,959	$214,266	$10,097	$16,208	$60,426
NI	Allocated Net Income (NI)	$128,400,000	$2,256,382	$35,153,778	$51,346,006	$1,941,276	$3,330,224	$11,326,017
	Revenue Requirement (includes NI)	$965,200,000	$21,550,635	$251,414,596	$372,012,905	$16,829,830	$27,854,076	$86,158,868
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$5,385,810,029	$101,852,610	$1,459,803,883	$2,128,758,298	$87,849,558	$145,662,108	$465,029,279
gp	General Plant - Gross	$567,678,044	$10,465,932	$151,365,133	$219,417,066	$8,936,357	$14,885,331	$47,187,058
accum dep	Accumulated Depreciation	($2,126,700,000)	($39,818,760)	($562,629,923)	($828,225,779)	($34,881,832)	($57,433,526)	($185,341,358)
co	Capital Contribution	($403,488,073)	($12,151,205)	($112,787,332)	($153,816,712)	($10,009,190)	($14,258,913)	($25,993,044)
	Total Net Plant	$3,423,300,000	$60,348,577	$935,751,762	$1,366,132,874	$51,894,893	$88,855,001	$300,881,934
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$1,863,400,000	$59,976,896	$289,217,776	$300,885,645	$26,077,432	$29,262,472	$153,695,973
	OM&A Expenses	$447,294,849	$12,636,149	$111,930,091	$168,005,711	$9,006,181	$14,464,924	$41,349,187
	USoA 5645 Adjustment of $23.6M	($23,600,000)	($669,836)	($5,898,499)	($8,857,065)	($476,629)	($765,060)	($2,183,068)
	USoA 5112/5114 Adjustment of $8.2M	($8,200,000)	($226,386)	($1,265,810)	($1,361,804)	($93,125)	($97,927)	($781,316)
	Directly Allocated Expenses	$7,605,151	$14,190	$124,959	$214,266	$10,097	$16,208	$60,426
	Subtotal	$2,286,500,000	$71,731,014	$394,108,517	$458,886,753	$34,523,957	$42,880,617	$192,141,202
	Working Capital [11.6% not 15%]	$265,599,840	$8,332,275	$45,779,645	$53,304,285	$4,010,303	$4,981,012	$22,319,122
	USoA 1330: Supplies Inventory -- based on O&M	$22,900,000	$649,968	$5,723,543	$8,594,356	$462,492	$742,367	$2,118,316
	Total Rate Base [per Exhibit D2-1-1]	$3,711,799,840	$69,330,820	$987,254,951	$1,428,031,515	$56,367,688	$94,578,380	$325,319,372
			Rate Base Input equals Output					
	Equity Component of Rate Base	$1,484,719,936	$27,732,328	$394,901,980	$571,212,606	$22,547,075	$37,831,352	$130,127,749
	Net Income	$128,400,000	$10,250,312	($52,863,113)	($51,352,623)	$10,843,864	$18,648,803	$36,240,972
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	137.09%	64.99%	72.39%	152.90%	155.00%	128.92%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$0	$7,993,930	($88,016,891)	($102,698,630)	$8,902,587	$15,318,579	$24,914,955
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.65%	36.96%	-13.39%	-8.99%	48.09%	49.29%	27.85%
	Net Income	$128,400,000	$10,250,312	($52,863,113)	($51,352,623)	$10,843,864	$18,648,803	$36,240,972
	Common Equity Component	$120,250,000	$9,599,689	($49,507,705)	($48,093,091)	$10,155,565	$17,465,098	$33,940,629
	Preferred Component	$8,150,000	$650,623	($3,355,408)	($3,259,532)	$688,298	$1,183,705	$2,300,342
	Equity Component of Rate Base: Common @ 36%	$1,336,247,942	$24,959,095	$355,411,782	$514,091,345	$20,292,368	$34,048,217	$117,114,974
	Equity Component of Rate Base: Preferred @ 4%	$148,471,994	$2,773,233	$39,490,198	$57,121,261	$2,254,708	$3,783,135	$13,012,775
	RETURN ON Common EQUITY COMPONENT OF RATE BASE	9.0%	38.5%	-13.9%	-9.4%	50.0%	51.3%	29.0%
	RETURN ON Preferred EQUITY COMPONENT OF RATE BASE	5.5%	23.5%	-8.5%	-5.7%	30.5%	31.3%	17.7%
	RETURN ON Composite EQUITY COMPONENT OF RATE BAS	8.6%	37.0%	-13.4%	-9.0%	48.1%	49.3%	27.9%
	$40.2M External Revenues Unique Allocation	$40,200,000	$ 2,454,498	$ 10,212,262	$ 10,898,478	$ 657,579	$ 1,150,971	$ 2,338,403
Dir	Sentinel Lgts	$3,600,000						
LPHA	Late Payments	$13,500,000	577,627	2,939,984	3,298,934	344,952	475,840	1,117,365
Connects	Account Set Up	$4,200,000	637,304	1,685,565	1,122,372	19,531	104,880	-
Connects	Collections	$700,000	106,217	280,928	187,062	3,255	17,480	-
Connects	New Connects + Upgrades	$5,000,000	758,695	2,006,625	1,336,157	23,251	124,857	-
O&M	Other - Mainly Joint Use	$12,800,000	$ 363,301	$ 3,199,186	$ 4,803,832	$ 258,511	$ 414,948	$ 1,184,037
O&M	Internal Transfer with Telecom	$400,000	$ 11,353	$ 99,975	$ 150,120	$ 8,078	$ 12,967	$ 37,001
	Allocated Costs based on Alloc External Revenues	$965,200,000	$21,560,567	$251,789,152	$373,387,107	$16,604,991	$27,902,393	$85,333,448
	CREV + Uniquie Allocation of Misc External Revenues	$965,200,000	$29,554,498	$163,772,262	$270,688,478	$25,507,579	$43,220,971	$110,248,403
	Rev to Cost Ratio -- External Rev CWNB Allocation		1.371	0.650	0.724	1.529	1.550	1.289
	Rev to Cost Ratio -- External Rev Unique Allocation	1.00	1.371	0.650	0.725	1.536	1.549	1.292

Output Sheet Showing Revenue to Cost Summary by Major C

Run 2: Hydro One Distribution with Customer Class

Class Revenue and Cost Analysis and Return on Rate Base

	7	8	9	10	11	12	13	14
	F3	**UG**	**G1**	**G3**	**T**	**St Lgts**	**Sentinel Lgts**	**AcqRes**
Distribution Revenue (sale)	$7,799,000	$16,035,310	$64,681,428	$90,210,789	$26,808,573	$4,652,565	$917,435	$37,290,000
Miscellaneous Revenue (mi) -- ***allocated by CWNB+LPHA***	$270,809	$451,285	$3,588,959	$3,337,063	$369,289	$162,565	$75,575	$3,061,354
Total Revenue	**$8,069,808**	**$16,486,595**	**$68,270,387**	**$93,547,852**	**$27,177,862**	**$4,815,131**	**$993,009**	**$40,351,354**
Expenses								
Distribution Costs (di)	$232,689	$1,090,329	$8,318,968	$8,333,461	$353,371	$299,978	$548,622	$8,309,022
Customer Related Costs (cu)	$451,840	$947,467	$6,979,915	$5,120,863	$432,175	$212,565	$454,520	$12,505,555
General and Administration (ad)	$202,193	$612,171	$4,557,433	$4,083,485	$239,769	$153,278	$293,351	$6,204,340
Depreciation and Amortization (dep)	$236,419	$954,755	$5,694,077	$7,842,383	$842,393	$179,661	$323,252	$7,837,991
PILs (INPUT)	$100,309	$435,926	$2,746,770	$3,519,767	$224,598	$101,693	$103,793	$3,782,892
Interest	$166,177	$722,173	$4,550,413	$5,830,993	$372,078	$168,469	$171,948	$6,266,897
Total Expenses	**$1,389,626**	**$4,762,820**	**$32,847,576**	**$34,730,952**	**$2,464,384**	**$1,115,645**	**$1,895,485**	**$44,906,697**
Direct Allocation	**$79,554**	**$189,472**	**$50,095**	**$1,328,477**	**$1,083,718**	**$746**	**$1,258,908**	**$30,281**
Allocated Net Income (NI)	$161,400	$701,414	$4,419,614	$5,663,385	$361,383	$163,627	$167,005	$6,086,759
Revenue Requirement (includes NI)	$1,630,580	$5,653,706	$37,317,285	$41,722,813	$3,909,486	$1,280,017	$3,321,398	$51,023,736
Rate Base Calculation								
Net Assets								
Distribution Plant - Gross	$7,449,801	$33,270,636	$191,272,317	$242,326,596	$17,945,547	$6,716,067	$6,978,023	$262,417,472
General Plant - Gross	$650,198	$3,194,203	$19,592,272	$23,622,507	$1,513,207	$676,833	$16,857,489	$27,288,541
Accumulated Depreciation	($3,595,935)	($14,337,900)	($75,144,676)	($102,310,875)	($8,976,441)	($2,704,331)	($12,700,843)	($100,672,376)
Capital Contribution	($224,872)	($3,389,698)	($17,860,444)	($13,176,802)	($879,072)	($343,592)	($738,843)	($26,599,131)
Total Net Plant	**$4,279,192**	**$18,737,242**	**$117,859,469**	**$150,461,426**	**$9,603,242**	**$4,344,977**	**$10,395,826**	**$162,434,505**
Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	$17,854,312	$47,411,952	$97,541,825	$214,442,275	$97,192,686	$9,188,807	$1,811,931	$112,354,981
OM&A Expenses	$886,722	$2,649,966	$19,856,316	$17,537,809	$1,025,315	$665,821	$1,296,493	$27,018,917
USoA 5645 Adjustment of $23.6M	($47,007)	($139,937)	($1,050,588)	($923,921)	($53,944)	($35,197)	($68,887)	($1,429,356)
USoA 5112/5114 Adjustment of $8.2M	($63,902)	($172,063)	($398,812)	($770,713)	($30,235)	($57,918)	($421)	($466,841)
Directly Allocated Expenses	$79,554	$189,472	$50,095	$1,328,477	$1,083,718	$746	$1,258,908	$30,281
Subtotal	$18,709,679	$49,939,390	$115,998,836	$231,613,927	$99,217,540	$9,762,258	$4,298,023	$137,507,982
Working Capital [11.6% not 15%]	**$2,173,316**	**$5,800,960**	**$13,474,425**	**$26,904,274**	**$11,525,109**	**$1,133,984**	**$499,258**	**$15,972,927**
USoA 1330: Supplies Inventory -- based on O&M	$45,613	$135,787	$1,019,427	$896,516	$52,344	$34,153	$66,843	$1,386,960
Total Rate Base [per Exhibit D2-1-1]	**$6,498,122**	**$24,673,988**	**$132,353,320**	**$178,262,216**	**$21,180,696**	**$5,513,113**	**$10,961,928**	**$179,794,392**
Equity Component of Rate Base	**$2,599,249**	**$9,869,595**	**$52,941,328**	**$71,304,886**	**$8,472,278**	**$2,205,245**	**$4,384,771**	**$71,917,757**
Net Income	**$6,600,629**	**$11,534,303**	**$35,372,716**	**$57,488,423**	**$23,629,759**	**$3,698,741**	**($2,161,384)**	**($4,585,623)**
RATIOS ANALYSIS								
REVENUE TO EXPENSES %	494.90%	291.61%	182.95%	224.21%	695.18%	376.18%	29.90%	79.08%
EXISTING REVENUE MINUS ALLOCATED COSTS	$6,439,229	$10,832,889	$30,953,101	$51,825,039	$23,268,376	$3,535,114	($2,328,389)	($10,672,382)
RETURN ON EQUITY COMPONENT OF RATE BASE	253.94%	116.87%	66.81%	80.62%	278.91%	167.72%	-49.29%	-6.38%
Net Income	$6,600,629	$11,534,303	$35,372,716	$57,488,423	$23,629,759	$3,698,741	($2,161,384)	($4,585,623)
Common Equity Component	$6,181,663	$10,802,181	$33,127,485	$53,839,431	$22,129,895	$3,463,968	($2,024,193)	($4,294,558)
Preferred Component	$418,965	$732,123	$2,245,231	$3,648,993	$1,499,864	$234,772	($137,191)	($291,066)
Equity Component of Rate Base: Common @ 36%	$2,339,324	$8,882,636	$47,647,195	$64,174,398	$7,625,050	$1,984,721	$3,946,294	$64,725,981
Equity Component of Rate Base: Preferred @ 4%	$259,925	$986,960	$5,294,133	$7,130,489	$847,228	$220,525	$438,477	$7,191,776
RETURN ON Common EQUITY COMPONENT OF RATE BASE	**264.3%**	**121.6%**	**69.5%**	**83.9%**	**290.2%**	**174.5%**	**-51.3%**	**-6.6%**
RETURN ON Preferred EQUITY COMPONENT OF RATE BASE	**161.2%**	**74.2%**	**42.4%**	**51.2%**	**177.0%**	**106.5%**	**-31.3%**	**-4.0%**
RETURN ON Composite EQUITY COMPONENT OF RATE BAS	**253.9%**	**116.9%**	**66.8%**	**80.6%**	**278.9%**	**167.7%**	**-49.3%**	**-6.4%**
$40.2M External Revenues Unique Allocation	**$ 100,599**	**$ 260,817**	**$ 1,543,157**	**$ 1,707,828**	**$ 344,087**	**$ 55,421**	**$ 3,645,576**	**$ 3,340,782**
Sentinel Lgts							$3,600,000	
Late Payments	74,307	177,502	821,841	1,010,062	312,023	35,734	7,046	1,426,947
Account Set Up	-	2,140	56,721	76,787	803	-	-	472,761
Collections	-	357	9,453	12,798	134	-	-	78,793
New Connects + Upgrades	-	2,548	67,525	91,413	956	-	-	562,811
Other - Mainly Joint Use	$ 25,495	$ 75,898	$ 569,811	$ 501,109	$ 29,258	$ 19,090	$ 37,362	$ 775,244
Internal Transfer with Telecom	$ 797	$ 2,372	$ 17,807	$ 15,660	$ 914	$ 597	$ 1,168	$ 24,226
Allocated Costs based on Alloc External Revenues	**$1,460,370**	**$5,463,239**	**$35,271,484**	**$40,093,579**	**$3,884,284**	**$1,172,872**	**$6,891,400**	**$51,303,164**
CREV + Uniquie Allocation of Misc External Revenues	**$7,899,599**	**$16,296,128**	**$66,224,585**	**$91,918,618**	**$27,152,660**	**$4,707,986**	**$4,563,011**	**$40,630,782**
Rev to Cost Ratio -- External Rev CWNB Allocation	4.949	2.916	1.829	2.242	6.952	3.762	0.299	0.791
Rev to Cost Ratio -- External Rev Unique Allocation	**5.409**	**2.983**	**1.878**	**2.293**	**6.990**	**4.014**	**0.662**	**0.792**

Output Sheet Showing Revenue to Cost Summary by Major C

Run 2: Hydro One Distribution with Customer Class

Class Revenue and Cost Analysis and Return on Rate Base

	15	16	17	18	19	20
	AcqGS<50	**AcqGS>50**	**AcqLU**	**LV-Dir+LDC**	**USL**	**Standby**
Distribution Revenue (sale)	$8,406,302	$22,277,654	$2,460,000	$25,162,980	$1,936,870	$1,081,093
Miscellaneous Revenue (mi) -- ***allocated by CWNB+LPHA***	$782,521	$669,953	$22,912	$185,539	$255,600	$11,137
Total Revenue	**$9,188,823**	**$22,947,607**	**$2,482,912**	**$25,348,519**	**$2,192,470**	**$1,092,230**
Expenses						
Distribution Costs (di)	$1,582,461	$1,828,694	$39,342	$7,103,737	$155,305	$282,715
Customer Related Costs (cu)	$1,986,053	$964,445	$37,203	$238,436	$350,265	$8,208
General and Administration (ad)	$1,058,233	$859,859	$23,540	$2,211,428	$148,192	$87,132
Depreciation and Amortization (dep)	$1,074,722	$1,712,364	$108,465	$4,152,836	$114,668	$139,624
PILs (INPUT)	$567,869	$905,964	$24,435	$1,692,045	$57,047	$60,071
Interest	$940,755	$1,500,857	$40,480	$2,803,112	$94,507	$99,515
Total Expenses	**$7,210,092**	**$7,772,183**	**$273,463**	**$18,201,596**	**$919,984**	**$677,265**
Direct Allocation	**$5,191**	**$962,538**	**$32,215**	**$2,142,652**	**$735**	**$423**
Allocated Net Income (NI)	$913,713	$1,457,716	$39,316	$2,722,539	$91,791	$96,655
Revenue Requirement (includes NI)	$8,128,997	$10,192,437	$344,994	$23,066,786	$1,012,510	$774,343
Rate Base Calculation						
Net Assets						
Distribution Plant - Gross	$41,377,995	$62,036,567	$2,096,242	$115,147,415	$3,763,581	$4,056,031
General Plant - Gross	$4,244,307	$5,990,045	$163,160	$10,852,767	$394,650	$380,990
Accumulated Depreciation	($16,221,066)	($26,532,274)	($1,129,160)	($50,820,715)	($1,424,408)	($1,797,823)
Capital Contribution	($4,960,955)	($2,801,044)	($86,032)	($3,040,715)	($290,689)	($79,789)
Total Net Plant	**$24,440,282**	**$38,693,294**	**$1,044,209**	**$72,138,753**	**$2,443,134**	**$2,559,409**
Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Cost of Power (COP)	$45,593,602	$124,196,137	$14,263,050	$222,432,248	$0	$0
OM&A Expenses	$4,626,747	$3,652,998	$100,084	$9,553,602	$653,762	$378,055
USoA 5645 Adjustment of $23.6M	($245,053)	($191,807)	($5,256)	($504,194)	($34,718)	($19,978)
USoA 5112/5114 Adjustment of $8.2M	($196,778)	($435,905)	($7,034)	($1,690,732)	($5,372)	($76,909)
Directly Allocated Expenses	$5,191	$962,538	$32,215	$2,142,652	$735	$423
Subtotal	$49,783,709	$128,183,961	$14,383,058	$231,933,576	$614,408	$281,591
Working Capital [11.6% not 15%]	**$5,782,876**	**$14,889,849**	**$1,670,736**	**$26,941,404**	**$71,370**	**$32,710**
USoA 1330: Supplies Inventory -- based on O&M	$237,785	$186,118	$5,100	$489,239	$33,688	$19,385
Total Rate Base [per Exhibit D2-1-1]	**$30,460,942**	**$53,769,261**	**$2,720,046**	**$99,569,396**	**$2,548,192**	**$2,611,504**
Equity Component of Rate Base	**$12,184,377**	**$21,507,704**	**$1,088,018**	**$39,827,758**	**$1,019,277**	**$1,044,601**
Net Income	**$1,973,540**	**$14,212,886**	**$2,177,233**	**$5,004,272**	**$1,271,750**	**$414,541**
RATIOS ANALYSIS						
REVENUE TO EXPENSES %	113.04%	225.14%	719.70%	109.89%	216.54%	141.05%
EXISTING REVENUE MINUS ALLOCATED COSTS	$1,059,826	$12,755,170	$2,137,917	$2,281,733	$1,179,960	$317,887
RETURN ON EQUITY COMPONENT OF RATE BASE	16.20%	66.08%	200.11%	12.56%	124.77%	39.68%
Net Income	$1,973,540	$14,212,886	$2,177,233	$5,004,272	$1,271,750	$414,541
Common Equity Component	$1,848,272	$13,310,744	$2,039,037	$4,686,633	$1,191,028	$388,229
Preferred Component	$125,268	$902,142	$138,197	$317,639	$80,722	$26,312
Equity Component of Rate Base: Common @ 36%	$10,965,939	$19,356,934	$979,216	$35,844,982	$917,349	$940,141
Equity Component of Rate Base: Preferred @ 4%	$1,218,438	$2,150,770	$108,802	$3,982,776	$101,928	$104,460
RETURN ON Common EQUITY COMPONENT OF RATE BASE	**16.9%**	**68.8%**	**208.2%**	**13.1%**	**129.8%**	**41.3%**
RETURN ON Preferred EQUITY COMPONENT OF RATE BASE	**10.3%**	**41.9%**	**127.0%**	**8.0%**	**79.2%**	**25.2%**
RETURN ON Composite EQUITY COMPONENT OF RATE BAS	**16.2%**	**66.1%**	**200.1%**	**12.6%**	**124.8%**	**39.7%**
$40.2M External Revenues Unique Allocation	**$ 521,258**	**$ 449,215**	**$ 23,440**	**$ 431,623**	**$ 45,115**	**$ 18,890**
Sentinel Lgts						
Late Payments	344,337	331,969	20,500	149,617	25,697	7,716
Account Set Up	16,909	4,227	-	-	-	-
Collections	2,818	705	-	-	-	-
New Connects + Upgrades	20,130	5,032	-	-	-	-
Other - Mainly Joint Use	$ 132,910	$ 104,031	$ 2,851	$ 273,461	$ 18,830	$ 10,836
Internal Transfer with Telecom	$ 4,153	$ 3,251	$ 89	$ 8,546	$ 588	$ 339
Allocated Costs based on Alloc External Revenues	**$7,867,734**	**$9,971,699**	**$345,523**	**$23,312,871**	**$802,026**	**$782,096**
CREV + Uniquie Allocation of Misc External Revenues	**$8,927,561**	**$22,726,870**	**$2,483,440**	**$25,594,604**	**$1,981,985**	**$1,099,983**
Rev to Cost Ratio -- External Rev CWNB Allocation	1.130	2.251	7.197	1.099	2.165	1.411
Rev to Cost Ratio -- External Rev Unique Allocation	**1.135**	**2.279**	**7.187**	**1.098**	**2.471**	**1.406**

Rogers Cable INTERROGATORY #6 List 1

Interrogatory

[Reference: Exhibit Gl, Tab 4, Schedule 5]

(a) Please confirm that for the purposes of deriving the fixed charge credit proposed to be applied to USL rates, costs from all of the following accounts have been removed, and please provide the unit rate amounts removed for each account: 5310 (meter reading expenses); 1970 (load management controls - customer premises); 1860 (meters); 5070 and 5075 (customer premises); 5175 (maintenance of meters); 5065 (meter expenses). If any of these costs have not been removed, please explain why.

(b) Please provide the amount of billing credit applied to USL rates in light of Hydro One's practice of providing summary (vs. account specific) billing.

(c) If Hydro One were to aggregate all USL facilities commonly owned to one billing account, what would be the additional credit applicable to the USL fixed charge? Could Hydro One do this? If not, why not?

Response

a. The USL metering credit is taken from the Cost Allocation Model sheet O3.5 USL Metering Credit.

Please see Exhibit G2, Tab 1, Schedule 1, Appendix A, page 49, for a listing of the Accounts and their balances which the Cost Model has used to develop the metering credit.

b. There is no "billing credit". Summary billing is a payment option customers can sign up for to receive one consolidated bill and excel summary spreadsheet to assist with managing their accounts, the USL metering credit applies to each USL account in the consolidated bill.

c. There would be no additional credit. Hydro One policy stipulates each power supply unit will be set up as an individual account. Establishing a separate account also identifies from a geographic area where the location of the unit is, for power outage purposes.

Rogers Cable INTERROGATORY #7 List 1

Interrogatory

[Reference: Exhibit G1, Tab 4, Schedule 1, page 1, lines 13 to 23; Exhibit G1, Tab 4, Schedule 2, page 2, Table 1] Please explain the criteria used to determine where in the fixed charge range the proposed fixed charge would be set for each customer class (i.e. at the low end, at the high end, or somewhere in the middle). Please include a description of how the criteria were applied to each customer class to determine the proposed fixed charge for that customer class.

Response

As described in Exhibit G1, Tab 4, Schedule 1, page 1, lines 13 to page 2 line 4, the Service Charge was chosen as the minimum of the fixed charge from the Cost Allocation Model Service Charge based on Minimum System or PLCC Adjustment, or the predominant rate group in the new Rate Class. Exhibit G1, Tab 4, Schedule 2 page 2, Table 1 shows the ranges for the fixed charges and the proposed fixed charges by customer class.

Rogers Cable INTERROGATORY #8 List 1

Interrogatory

[Reference: Exhibit G1, Tab 8, Schedule 1, page 3, lines 13-18] Please elaborate on the sentence; *"The shortfall in revenues resulting from this mitigation measure for USL customers is being recovered from the current USL General Service single-phase energy billed customers."* Specifically, what customers are receiving the benefits of mitigation, and what customers are paying for these benefits? What amount is involved in each of2008, 2009 and 2010? For a USL connection with 436 kWh per month, what is the monthly bill impact of the mitigation in each year? Please show the computation.

Response

To mitigate the impact of harmonizing the approximately 900 USL accounts in the Acquired LDCs, higher variable rates were set for the approximately 4,000 Legacy USL accounts so the revenue requirement for all USL is recovered every year. Specifically, the 900 Acquired USL accounts are receiving the mitigation benefit at the expense of the 4,000 Legacy USL accounts.

For the Legacy USL accounts, the mitigation increases their costs in 2008 by $170,000 and in 2009 by $70,000. There is no mitigation required in 2010. The Table below shows the volumetric rate without mitigation (Phase-In), the mitigated rate (G1 USL), the difference (Delta) and the dollar impact based on 436 kWh consumption.

	Phase-In	G1 USL	Delta	436 kWh
	[¢/kWh]	[¢/kWh]	[¢/kWh]	Impact
2008	4.44	5.38	0.93	$ 4.08
2009	4.11	4.52	0.41	$ 1.79
2010	3.78	3.67	(0.11)	$ (0.50)
2011	3.39	3.39	-	$ -

Rogers Cable INTERROGATORY #9 List 1

Interrogatory

[Reference: Exhibit G1, Tab 8, Schedule 1, page 3, lines 13-18] The general rate mitigation plan proposed includes limiting 2008 total bill impacts to 10%. For USL customers, the principle is to set a volumetric charge that results in annual bill impacts near $10 per month. Does the USL mitigation proposal result in total bill impacts in 2008 for USL customers of no more than 10%? If not, what is the rationale for adopting a different mitigation proposal for USL customers relative to other customers? If the same mitigation proposal were adopted for all customers (i.e. if USL rate impacts were limited to 10% in 2008), what would the resulting USL rates be?

Response

The USL mitigation was to limit dollar impacts to near $10 per month based on 500 kWh. The $10 level does result in some USL customers having impacts exceeding the 10% level.

A different mitigation rationale for the USL was chosen to accommodate the fact that for the 900 Acquired accounts, their existing service charges were set in 2006 to be at 50% of the GS<50 kW rate. This lower rate makes mitigation impacts more difficult on a percentage basis so a dollar basis was deemed more appropriate.

If the impacts for the approximately 900 Acquired customers are to be limited to 10% on total bill in 2008, the Legacy G1 USL variable rate would need to increase to 5.45 ¢/kWh from 5.38 ¢/kWh - an extra $24,000 of expense to G1 for an additional impact of $0.31 based on 436 kWh. However, the G1 USL would now exceed 10% to achieve the USL Revenue Requirement.

Rogers Cable INTERROGATORY #10 List 1

Interrogatory

[Reference: Exhibit G1, Tab 8, Schedule 1, Page 4, Table 2] If USL is included in the General Service Energy class, and if the range of bill impacts for that class after mitigation, according to Table 2, is a reduction of 8.4% to an increase of 2.5%, should it be concluded that the impact of the proposed rate changes on USL connections would not exceed an increase of 2.5% on a total bill basis? If this is not a correct understanding of Table 2, please explain how to interpret this table.

Response

The General Service Energy impact range in Table 2 only shows the range of impacts for existing Legacy Rate classes moving to the new General Service Energy class and excludes the USL subclass.

Rogers Cable INTERROGATORY #11 List 1

Interrogatory

[Reference: Exhibit G2, Tab 5, Schedule 1, pages 10 and 11; Exhibit G2, Tab 5, Schedule 2, page 10; Exhibit G2, Tab 35, Schedule 1, page 4; Exhibit G2, Tab 35, Schedule 2, page 4]

(a) Please verify the correctness of the table below, computing the distribution and total bill impacts for a USL connection with estimated monthly consumption of 436 kWh per month. If any data or computations are not correct, please provide the correct data or computations with an explanation of the correction made.

(b) Please provide a table that lists proposed total bill and distribution only 2008 vs. 2007 impacts, as percentages, for USL customers in each of the acquired LDC service territories, assuming USL consumption at 436 KWh per month and both before and after application of any rate mitigation proposal.

Bill Comparison 2008 Proposed Rates and 2007 Approved Rates
Hydro One Networks
Unmetered Scattered Load Connection, 436 kWh per Month

	2008	Rates 2007	2008				2007
	Proposed	Approved	Billing **Determinant**	Computed Bill	Billing **Determinant**	Computed Bill	**Increase (%)**
FormerG1							
Service Charge	$ 22.8400	22.16 0.0312	1	22.8400	1	22.1600	
Distribution Volumetric	$ 0.0538		436	23.4568	436	13.6032	
Regulatory Asset Recovery Rider #1		0.0009	436		436	0.3924	
Regulatory Asset Recovery Rider #2	$ 0.0009 $	0.0009	436	0.3924	436	0.3924	
Regulatory Asset Recovery Rider #3	(00006)		436	(0.2616)	436	0.0000	
Retail Transmission Network Service	$ 0.0035	0.0052	476	1.6664	476	2.4758	
Retail Transmission Line and Transformer Connection	$ 0.0032	0.0034	476	1.5236	476	1.6188	
Wholesale Market Service Rate	$ 0.0052	0.0052	476	2.4758	476	2.4758	
Ruralor Remote RateProtection	$ 0.0010	0.001	476	0.4761	476	0.4761	
Standard Supply Administration	$ 0.2500 $	0.25	1	0.2500	1	0.2500	
Commodity Rate (assumed average)	0.0500	0.05	476	23.8056	476	23.8056	
Debt Recovery Charge	$ 0.0070	0.007	436	3.0520	436	3.0520	
Total Bill				$ 79.68		$ 70.70	12.7 %
Distribution Only				$ 46.30		$ 35.76	29,5 %
FormerG3							
Service Charge	$ 10.8100 $	6.29	1	10.8100	1	6.2900	
Distribution Volumetric	0.0360	0.0307	436	15.6960	436	13.3852	
		0.0002	436		436	0.0872	
Regulatory Asset Recovery Rider #1		0.0005	436		436	0.2180	
Regulatory Asset Recovery Rider #2	$ 0.0005 $		436	0.2180	436	0.0000	
Regulatory Asset Recovery Rider #3	(00006) $		476	(0.2616)	476	2.4758	
Retail Transmission Network Service	0.0035	0.0052		1.6664			
Retail Transmission Line and Transformer Connection	$ 0.0032	0.0033	476	1.5236	476	1.5712	
Wholesale Market Service Rate	$ 0.0052	0.0052	476	2.4758	476	2.4758	
Rural or Remote Rate Protection	$ 0.0010	0.001	476	0.4761	476	0.4761	
Standard Supply Administration	$ 0.2500 $	0.25	1	0.2500	1	0.2500	
Commodity Rate (assumed average)	0.0500 $	0.05	476	23.8056	476	23.8056	
Debt Recovery Charge	0.0070	0.007	436	3.0520	436	3.0520	
Total Bill				59.71		$ 54.09	10.4%
Distribution Only				26.51		$ 19.68	34.7%
FormerUG							
Service Charge	$ 6.1800 $	0.79	1	6.1800	1	0.7900	
Distribution Volumetric	0.0350	0.0274	436	15.2600	436	11.9464	
		0.0003	436		436	0.1308	
Regulatory Asset Recovery Rider #1	$ 0.0003 $	0.0003	436	0.1308	436	0.1308	
Regulatory Asset Recovery Rider #2	(0.0006) $		436	(0.2616)	436	0.0000	
Regulatory Asset Recovery Rider #3	0.0035	0.0052	476	1.6684	476	2.4758	
Retail Transmission Network Service							
Retail Transmission Line and Transformer Connection	$ 0.0032	0.0033	476	1.5236	476	1.5712	
Wholesale Market Service Rate	$ 0.0052	0.0052	476	2.4758	476	2.4758	
Rural or Remote Rate Protection	$ 0.0010	0.001	476	0.4761	476	0.4761	
Standard Supply Administration	$ 0.2500 $	0.25	1	0.2500	1	0.2500	
Commodity Rate (assumed average)	0.0500 $	0.05	476	23.8056	476	23.8056	
Debt Recovery Charge	0.0070	0.007	436	3.0520	436	3.0520	
Total Bill				$ 54.56		$ 47.10	15,8%
Distribution Only				$ 21.44		$ 12.74	68.3%
Loss Factor			1.0920		1.0920		
Fenelon Falls							
Service Charge	13.0200	9.43	1	13.0200	1	9.4300	
Distribution Volumetric	0.0200	0.0095	436	8.7200	436	4.1420	
		0.0015					
Regulatory Asset Recovery Rider #1	0.0008 -	0.0008	436		436	0.6540	
RegUlatory Asset Recovery Rider #2	0.0006		436	0.3488	436	0.3488	
Regulatory Asset Recovery Rider #3	0.0035	0.005	436	(02616)	436	0.0000	
Retail Transmission Network Service			476	1.6664	460	2.2988	
Retail Transmission Line and Transformer Connection	0.0032	0.0043	476	1.5236	460	1.9770	
Wholesale Market Service Rate	0.0052	0.0052	476	2.4758	460	2.3908	
Rural or Remote Rate Protection	0.001	0.001	476	0.4761	460	0.4598	
Standard Supply Administration	0.25	0.25	1	0.2500	1	0.2500	
Commodity Rate (assumed average)	0.05	0.05	476	23.8056	460	22.9881	
Debt Recovery Charge	0.007	0.007	436	3.0520	436	3.0520	
Total Bill				$ 55.08		47.99	14.8%
Distribution Only				$ 21.74		13.57	60.2%
Loss Factor			1.0920		1.0545		

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Response

a. For Distribution impacts, please refer to Exhibit G2, Tab 5, Schedule 1, pages 77 to 95 and for Total impacts please refer to Exhibit G2, Tab 5, Schedule 6, pages 77 to 95.

The calculation has been reviewed at 436 kWh and the only error noticed was that for the G3 USL scenario, the existing loss factor is 1.061 not 1.092 as assumed in the table. Overall, the impacts calculated are correct.

b. The mitigation being proposed is to limit the average Acquired USL account impact to approximately $10, a lower variable rate is selected for each Acquired Distributor. The reduced revenue from this variable rate is recovered from a higher variable rate for the Legacy USL accounts. For the no mitigation scenario, a common variable rate is used for all Acquireds and Legacy rate classes to achieve the class revenue requirement.

Attachment A list the Distribution Only and Total Bill impacts for the Acquired Distributor USL accounts at the requested 436 kWh level.

Acquired Distributor — Distribution Only @ 436 kWh

	Existing 2007	Mitigated 2008	Not-Mitigated 2008	Mitigated $ Incr	Not-Mitigated $ Incr	Mitigated % Incr	Not Mitigated % Incr
Ailsa Craig	$ 13.96	$ 21.05	$ 31.70	$ 7.09	17.75	51%	127%
Arkona	$ 4.89	$ 15.81	$ 26.47	$ 10.92	21.58	223%	441%
Arnprior	$ 15.33	$ 22.54	$ 33.20	$ 7.21	17.86	47%	117%
Arran-Elderslie	$ 8.44	$ 17.11	$ 27.77	$ 8.67	19.33	103%	229%
Artemesia	$ 16.93	$ 21.76	$ 32.42	$ 4.84	15.49	29%	92%
Bancroft	$ 16.87	$ 23.17	$ 33.82	$ 6.29	16.95	37%	100%
Bath	$ 11.27	$ 17.88	$ 28.54	$ 6.61	17.27	59%	153%
Blandford-Blenheim	$ 16.43	$ 23.23	$ 33.89	$ 6.80	17.46	41%	106%
Blyth	$ 14.93	$ 22.51	$ 33.17	$ 7.58	18.24	51%	122%
Bobcaygeon	$ 17.16	$ 23.31	$ 33.97	$ 6.16	16.81	36%	98%
Brighton	$ 16.88	$ 22.35	$ 33.01	$ 5.47	16.13	32%	96%
Brockville	$ 13.77	$ 22.51	$ 33.16	$ 8.73	19.39	63%	141%
Caledon	$ 19.48	$ 23.19	$ 33.85	$ 3.71	14.37	19%	74%
Campbellford-Seymour	$ 12.82	$ 20.19	$ 30.85	$ 7.37	18.03	58%	141%
Carleton Place	$ 18.68	$ 23.26	$ 33.91	$ 4.57	15.23	24%	82%
Cavan-Millbrook-North Monaghan	$ 17.22	$ 22.43	$ 33.08	$ 5.21	15.86	30%	92%
Centre Hastings	$ 12.96	$ 20.92	$ 31.57	$ 7.96	18.61	61%	144%
Chalk River	$ 18.00	$ 22.55	$ 33.20	$ 4.54	15.20	25%	84%
Champlain	$ 13.80	$ 21.64	$ 32.30	$ 7.84	18.50	57%	134%
Cobden	$ 19.79	$ 22.47	$ 33.13	$ 2.69	13.34	14%	67%
Deep River	$ 21.35	$ 23.22	$ 33.88	$ 1.87	12.52	9%	59%
Deseronto	$ 10.50	$ 17.95	$ 28.60	$ 7.45	18.11	71%	172%
Dryden	$ 13.58	$ 21.83	$ 32.48	$ 8.24	18.90	61%	139%
Dundalk	$ 18.47	$ 23.27	$ 33.92	$ 4.80	15.45	26%	84%
Durham	$ 17.56	$ 23.20	$ 33.86	$ 5.64	16.29	32%	93%
Eganville	$ 20.34	$ 22.54	$ 33.20	$ 2.21	12.86	11%	63%
Erin	$ 22.90	$ 29.17	$ 39.82	$ 6.26	16.92	27%	74%
Exeter	$ 10.88	$ 18.80	$ 29.45	$ 7.92	18.57	73%	171%
Fenelon Falls	$ 13.57	$ 21.74	$ 32.40	$ 8.17	18.82	60%	139%
Forest	$ 17.12	$ 23.10	$ 33.76	$ 5.98	16.63	35%	97%
GBE	$ 9.89	$ 17.87	$ 28.52	$ 7.98	18.63	81%	188%
Georgina	$ 15.30	$ 21.04	$ 31.69	$ 5.73	16.39	37%	107%
Glencoe	$ 8.74	$ 18.80	$ 29.45	$ 10.05	20.71	115%	237%
Grand Bend	$ 15.99	$ 22.44	$ 33.10	$ 6.45	17.10	40%	107%
Hastings	$ 18.35	$ 22.35	$ 33.01	$ 4.00	14.66	22%	80%
Havelock	$ 17.26	$ 22.44	$ 33.10	$ 5.18	15.84	30%	92%
Kirkfield	$ 15.38	$ 19.38	$ 30.03	$ 4.00	14.65	26%	95%
Lanark Highlands	$ 17.43	$ 20.91	$ 31.57	$ 3.48	14.14	20%	81%
Larder Lake	$ 16.51	$ 21.69	$ 32.35	$ 5.18	15.84	31%	96%
Latchford	$ 5.42	$ 14.86	$ 25.51	$ 9.44	20.09	174%	371%
Lindsay	$ 17.52	$ 23.22	$ 33.88	$ 5.71	16.36	33%	93%
Lucan Granton	$ 14.44	$ 21.09	$ 31.75	$ 6.65	17.31	46%	120%
Malahide	$ 16.08	$ 20.24	$ 30.89	$ 4.15	14.81	26%	92%
Mapleton	$ 17.78	$ 22.52	$ 33.17	$ 4.74	15.40	27%	87%
Markdale	$ 14.53	$ 23.34	$ 33.99	$ 8.81	19.47	61%	134%
Marmora	$ 9.12	$ 17.96	$ 28.62	$ 8.84	19.50	97%	214%
McGarry	$ 18.24	$ 21.72	$ 32.37	$ 3.48	14.13	19%	77%
Meaford	$ 16.91	$ 23.21	$ 33.87	$ 6.30	16.95	37%	100%
Middlesex Centre	$ 14.18	$ 21.05	$ 31.70	$ 6.86	17.52	48%	124%
Napanee	$ 16.20	$ 22.44	$ 33.10	$ 6.24	16.90	39%	104%
Nipigon	$ 15.77	$ 23.30	$ 33.96	$ 7.53	18.19	48%	115%
North Dorchester	$ 11.39	$ 20.23	$ 30.89	$ 8.84	19.49	78%	171%
North Dundas	$ 9.91	$ 19.53	$ 30.18	$ 9.62	20.27	97%	205%
North Glengarry	$ 12.32	$ 21.00	$ 31.65	$ 8.67	19.33	70%	157%
North Grenville	$ 17.20	$ 21.66	$ 32.32	$ 4.47	15.12	26%	88%
North Perth	$ 18.66	$ 25.52	$ 36.18	$ 6.86	17.52	37%	94%
North Stormont	$ 5.62	$ 16.54	$ 27.20	$ 10.92	21.58	194%	384%

Acquired Distributor — Distribution Only @ 436 kWh

	Existing 2007	Mitigated 2008	Not-Mitigated 2008	Mitigated $ Incr	Not-Mitigated $ Incr	Mitigated % Incr	Not Mitigated % Incr
Omemee	$ 16.59	$ 22.55	$ 33.21	$ 5.96	16.62	36%	100%
Perth	$ 13.50	$ 21.73	$ 32.38	$ 8.22	18.88	61%	140%
Perth East	$ 12.48	$ 19.38	$ 30.04	$ 6.90	17.55	55%	141%
Prince Edward	$ 17.15	$ 22.36	$ 33.01	$ 5.21	15.86	30%	92%
Quinte West	$ 5.99	$ 15.75	$ 26.40	$ 9.76	20.41	163%	341%
Rainy River	$ 16.85	$ 21.80	$ 32.46	$ 4.95	15.60	29%	93%
Ramara	$ 14.64	$ 22.59	$ 33.25	$ 7.95	18.61	54%	127%
Red Rock	$ 18.82	$ 22.51	$ 33.16	$ 3.69	14.35	20%	76%
Rockland	$ 7.52	$ 17.31	$ 27.96	$ 9.79	20.44	130%	272%
Russell	$ 18.94	$ 21.81	$ 32.46	$ 2.87	13.52	15%	71%
Schreiber	$ 20.82	$ 21.63	$ 32.28	$ 0.80	11.46	4%	55%
Severn	$ 15.24	$ 22.44	$ 33.10	$ 7.20	17.86	47%	117%
Shelburne	$ 13.32	$ 21.72	$ 32.37	$ 8.39	19.05	63%	143%
Smiths Falls	$ 9.04	$ 17.98	$ 28.64	$ 8.94	19.60	99%	217%
South Glengarry	$ 11.52	$ 21.04	$ 31.69	$ 9.52	20.17	83%	175%
South River	$ 17.48	$ 22.45	$ 33.11	$ 4.97	15.63	28%	89%
Springwater	$ 14.47	$ 21.65	$ 32.30	$ 7.18	17.84	50%	123%
Stirling-Rawdon	$ 17.26	$ 23.20	$ 33.86	$ 5.94	16.60	34%	96%
Thedford	$ 13.07	$ 20.99	$ 31.64	$ 7.91	18.57	61%	142%
Thessalon	$ 15.75	$ 20.85	$ 31.51	$ 5.10	15.76	32%	100%
Thorndale	$ 11.24	$ 19.40	$ 30.06	$ 8.16	18.82	73%	167%
Thorold	$ 17.39	$ 22.39	$ 33.04	$ 5.00	15.65	29%	90%
Tweed	$ 7.90	$ 17.18	$ 27.84	$ 9.28	19.94	117%	252%
Wardsville	$ 10.06	$ 18.67	$ 29.33	$ 8.61	19.27	86%	192%
Warkworth	$ 16.83	$ 22.55	$ 33.20	$ 5.72	16.38	34%	97%
West Elgin	$ 10.28	$ 20.29	$ 30.95	$ 10.01	20.66	97%	201%
Whitchurch Stouffville	$ 14.51	$ 22.48	$ 33.14	$ 7.97	18.62	55%	128%
Wiarton	$ 19.66	$ 23.24	$ 33.90	$ 3.58	14.24	18%	72%
Woodville	$ 14.83	$ 20.10	$ 30.76	$ 5.28	15.93	36%	107%
Wyoming	$ 14.54	$ 21.04	$ 31.70	$ 6.50	17.16	45%	118%
Terrace Bay	$ 26.15	$ 29.97	$ 40.62	$ 3.81	14.47	15%	55%

Acquired Distributor — Total Bill @ 436 kWh

	Existing 2007	Mitigated 2008	Not-Mitigated 2008	Mitigated $ Incr	Not-Mitigated $ Incr	Mitigated % Incr	Not Mitigated % Incr
Ailsa Craig	$ 48.26	$ 54.19	$ 64.85	$ 5.94	$ 16.59	12%	34%
Arkona	$ 41.85	$ 50.13	$ 60.79	$ 8.29	$ 18.94	20%	45%
Arnprior	$ 49.46	$ 55.55	$ 66.21	$ 6.10	$ 16.75	12%	34%
Arran-Elderslie	$ 42.74	$ 50.25	$ 60.91	$ 7.51	$ 18.17	18%	43%
Artemesia	$ 53.71	$ 56.00	$ 66.65	$ 2.29	$ 12.94	4%	24%
Bancroft	$ 51.13	$ 56.27	$ 66.92	$ 5.13	$ 15.79	10%	31%
Bath	$ 46.75	$ 51.68	$ 62.34	$ 4.93	$ 15.59	11%	33%
Blandford-Blenheim	$ 51.69	$ 56.86	$ 67.51	$ 5.17	$ 15.82	10%	31%
Blyth	$ 50.10	$ 56.13	$ 66.79	$ 6.03	$ 16.69	12%	33%
Bobcaygeon	$ 51.50	$ 56.46	$ 67.11	$ 4.96	$ 15.61	10%	30%
Brighton	$ 51.26	$ 55.45	$ 66.11	$ 4.19	$ 14.84	8%	29%
Brockville	$ 47.68	$ 55.43	$ 66.09	$ 7.75	$ 18.41	16%	39%
Caledon	$ 53.60	$ 56.29	$ 66.95	$ 2.69	$ 13.34	5%	25%
Campbellford-Seymour	$ 46.94	$ 53.16	$ 63.82	$ 6.22	$ 16.87	13%	36%
Carleton Place	$ 52.72	$ 56.31	$ 66.97	$ 3.59	$ 14.25	7%	27%
Cavan-Millbrook-North Monaghan	$ 52.96	$ 56.31	$ 66.97	$ 3.35	$ 14.01	6%	26%
Centre Hastings	$ 47.00	$ 53.93	$ 64.58	$ 6.93	$ 17.59	15%	37%
Chalk River	$ 54.35	$ 56.78	$ 67.44	$ 2.43	$ 13.08	4%	24%
Champlain	$ 48.75	$ 55.05	$ 65.70	$ 6.29	$ 16.95	13%	35%
Cobden	$ 55.83	$ 56.53	$ 67.19	$ 0.70	$ 11.36	1%	20%
Deep River	$ 55.78	$ 56.59	$ 67.24	$ 0.80	$ 11.46	1%	21%
Deseronto	$ 44.45	$ 50.92	$ 61.57	$ 6.47	$ 17.12	15%	39%
Dryden	$ 47.44	$ 54.75	$ 65.41	$ 7.31	$ 17.96	15%	38%
Dundalk	$ 53.03	$ 56.41	$ 67.07	$ 3.38	$ 14.04	6%	26%
Durham	$ 51.65	$ 56.21	$ 66.87	$ 4.57	$ 15.22	9%	29%
Eganville	$ 54.77	$ 55.82	$ 66.47	$ 1.05	$ 11.71	2%	21%
Erin	$ 57.25	$ 62.27	$ 72.92	$ 5.02	$ 15.68	9%	27%
Exeter	$ 44.96	$ 51.81	$ 62.46	$ 6.85	$ 17.50	15%	39%
Fenelon Falls	$ 47.74	$ 54.84	$ 65.50	$ 7.10	$ 17.76	15%	37%
Forest	$ 51.25	$ 56.12	$ 66.77	$ 4.87	$ 15.52	9%	30%
GBE	$ 44.02	$ 50.88	$ 61.54	$ 6.87	$ 17.52	16%	40%
Georgina	$ 49.52	$ 54.14	$ 64.79	$ 4.62	$ 15.28	9%	31%
Glencoe	$ 43.48	$ 52.16	$ 62.81	$ 8.68	$ 19.34	20%	44%
Grand Bend	$ 50.29	$ 55.50	$ 66.15	$ 5.20	$ 15.86	10%	32%
Hastings	$ 52.91	$ 55.50	$ 66.15	$ 2.59	$ 13.24	5%	25%
Havelock	$ 51.51	$ 55.58	$ 66.24	$ 4.07	$ 14.73	8%	29%
Kirkfield	$ 53.13	$ 54.05	$ 64.70	$ 0.92	$ 11.58	2%	22%
Lanark Highlands	$ 55.52	$ 55.84	$ 66.50	$ 0.32	$ 10.98	1%	20%
Larder Lake	$ 53.47	$ 56.01	$ 66.67	$ 2.55	$ 13.20	5%	25%
Latchford	$ 42.29	$ 48.48	$ 59.14	$ 6.19	$ 16.85	15%	40%
Lindsay	$ 51.60	$ 56.24	$ 66.89	$ 4.64	$ 15.29	9%	30%
Lucan Granton	$ 48.78	$ 54.28	$ 64.93	$ 5.50	$ 16.15	11%	33%
Malahide	$ 54.92	$ 55.12	$ 65.78	$ 0.21	$ 10.86	0%	20%
Mapleton	$ 53.95	$ 56.53	$ 67.19	$ 2.58	$ 13.24	5%	25%
Markdale	$ 48.52	$ 56.26	$ 66.92	$ 7.74	$ 18.40	16%	38%
Marmora	$ 43.16	$ 50.93	$ 61.59	$ 7.78	$ 18.43	18%	43%
McGarry	$ 56.07	$ 56.65	$ 67.31	$ 0.58	$ 11.23	1%	20%
Meaford	$ 51.08	$ 56.27	$ 66.92	$ 5.19	$ 15.84	10%	31%
Middlesex Centre	$ 50.79	$ 55.32	$ 65.98	$ 4.53	$ 15.19	9%	30%
Napanee	$ 50.33	$ 55.46	$ 66.11	$ 5.13	$ 15.79	10%	31%
Nipigon	$ 51.33	$ 56.97	$ 67.62	$ 5.64	$ 16.29	11%	32%
North Dorchester	$ 47.22	$ 54.12	$ 64.77	$ 6.90	$ 17.55	15%	37%
North Dundas	$ 43.95	$ 52.45	$ 63.11	$ 8.50	$ 19.16	19%	44%
North Glengarry	$ 46.93	$ 54.27	$ 64.93	$ 7.34	$ 18.00	16%	38%
North Grenville	$ 51.32	$ 54.76	$ 65.42	$ 3.44	$ 14.10	7%	27%
North Perth	$ 52.52	$ 58.45	$ 69.11	$ 5.93	$ 16.58	11%	32%
North Stormont	$ 41.53	$ 50.43	$ 61.08	$ 8.89	$ 19.55	21%	47%

Acquired Distributor — Total Bill @ 436 kWh

	Existing 2007	Mitigated 2008	Not-Mitigated 2008	Mitigated $ Incr	Not-Mitigated $ Incr	Mitigated % Incr	Not Mitigated % Incr
Omemee	$ 50.93	$ 55.70	$ 66.35	$ 4.76	$ 15.42	9%	30%
Perth	$ 47.41	$ 54.65	$ 65.31	$ 7.24	$ 17.90	15%	38%
Perth East	$ 46.74	$ 52.53	$ 63.18	$ 5.79	$ 16.44	12%	35%
Prince Edward	$ 51.45	$ 55.46	$ 66.11	$ 4.01	$ 14.66	8%	28%
Quinte West	$ 40.03	$ 48.76	$ 59.41	$ 8.73	$ 19.39	22%	48%
Rainy River	$ 53.55	$ 56.12	$ 66.78	$ 2.57	$ 13.23	5%	25%
Ramara	$ 51.38	$ 56.96	$ 67.61	$ 5.57	$ 16.23	11%	32%
Red Rock	$ 54.21	$ 56.31	$ 66.96	$ 2.10	$ 12.75	4%	24%
Rockland	$ 42.39	$ 51.02	$ 61.67	$ 8.63	$ 19.29	20%	46%
Russell	$ 53.37	$ 55.04	$ 65.69	$ 1.67	$ 12.33	3%	23%
Schreiber	$ 57.91	$ 56.12	$ 66.78	$ (1.79)	$ 8.87	-3%	15%
Severn	$ 50.72	$ 56.15	$ 66.81	$ 5.44	$ 16.09	11%	32%
Shelburne	$ 47.01	$ 54.55	$ 65.21	$ 7.54	$ 18.20	16%	39%
Smiths Falls	$ 42.90	$ 50.91	$ 61.57	$ 8.01	$ 18.66	19%	44%
South Glengarry	$ 47.61	$ 55.10	$ 65.75	$ 7.49	$ 18.14	16%	38%
South River	$ 53.65	$ 56.51	$ 67.17	$ 2.86	$ 13.51	5%	25%
Springwater	$ 49.55	$ 55.14	$ 65.80	$ 5.59	$ 16.25	11%	33%
Stirling-Rawdon	$ 51.73	$ 56.34	$ 67.00	$ 4.61	$ 15.27	9%	30%
Thedford	$ 49.16	$ 55.09	$ 65.74	$ 5.93	$ 16.59	12%	34%
Thessalon	$ 49.70	$ 53.95	$ 64.61	$ 4.25	$ 14.91	9%	30%
Thorndale	$ 48.07	$ 53.55	$ 64.20	$ 5.48	$ 16.14	11%	34%
Thorold	$ 51.47	$ 55.40	$ 66.05	$ 3.93	$ 14.58	8%	28%
Tweed	$ 44.29	$ 51.28	$ 61.94	$ 6.99	$ 17.65	16%	40%
Wardsville	$ 44.67	$ 51.77	$ 62.43	$ 7.11	$ 17.76	16%	40%
Warkworth	$ 53.53	$ 56.83	$ 67.48	$ 3.30	$ 13.96	6%	26%
West Elgin	$ 44.49	$ 53.35	$ 64.00	$ 8.85	$ 19.51	20%	44%
Whitchurch Stouffville	$ 48.34	$ 55.41	$ 66.07	$ 7.07	$ 17.73	15%	37%
Wiarton	$ 54.05	$ 56.39	$ 67.04	$ 2.34	$ 13.00	4%	24%
Woodville	$ 53.01	$ 54.95	$ 65.60	$ 1.94	$ 12.60	4%	24%
Wyoming	$ 48.71	$ 54.10	$ 64.76	$ 5.39	$ 16.04	11%	33%
Terrace Bay	$ 60.47	$ 62.72	$ 73.37	$ 2.25	$ 12.91	4%	21%

Rogers Cable INTERROGATORY #12 List 1

Interrogatory

[Reference: Exhibit G2, Tab 96, Schedule 1, page 85] Please confirm that there are no plans to require metering of any USL location not currently metered.

Response

At this time there are no plans to require metering of existing USL location, as long as the established USL continues to satisfy existing Hydro One policies.

Milton Hydro (MH) INTERROGATORY #1 List 1

Interrogatory

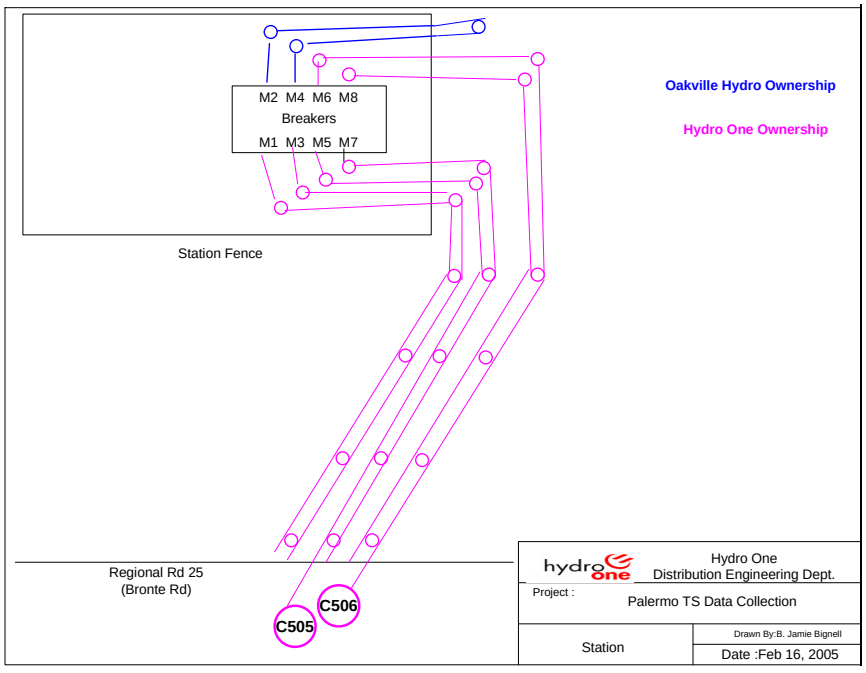
Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Attached to this document is a map prepared by Milton Hydro, which shows schematically the area surrounding the Hydro One Networks' Palermo Transformer Station ("Palermo TS") in Oakville abutting Halton Regional Road 25, the boundary with Milton, near the point at which Hydro One Networks' Corridor crosses Regional Road 25.

Can you please confirm that the schematic map reasonably portrays the position of the Palermo TS, the location of Hydro One Networks' property, the location of the M-1 and M-3 feeders which supply Milton Hydro, the M-5 and M-6 feeders that supply Burlington Hydro, and the M-8 , M-7, M-4 and M-2 feeders that supply the Town of Oakville.

Response

For greater clarity regarding the relative position of Palermo TS and the feeders that connect at this station, Hydro One also provides the attached diagram.



Milton Hydro (MH) INTERROGATORY #2 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Can you confirm that Hydro One owns that portion of the M-1 and M-3 feeders that are on Hydro One's property, and that this portion of the two feeder lines is about .24 km. in length.

Response

Yes.

Milton Hydro (MH) INTERROGATORY #3 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Can you confirm that the remainder of the M-1 and M-3 feeder lines, the part which lies along the road allowance of Regional Road 25, and into Milton Hydro's territory, is not owned by Hydro One but is owned by Milton Hydro and is approximately 2 km. long.

Response

This line portion is not owned by Hydro One and we cannot confirm the length.

Milton Hydro (MH) INTERROGATORY 4 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Can you confirm that there are currently five wooden poles supporting the M-1 and M-3 feeder lines on Hydro One's property.

Response

Yes.

Milton Hydro (MH) INTERROGATORY 5 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Can you confirm that Milton Hydro's payments for LV charges for service from feeders M-1 and M-3 over the period May 1, 2002 to January 1, 2008 are approximately $608,831.00, and that, had Milton Hydro been charged on the basis that the M-1 and M-3 feeders were specific LV lines, Milton Hydro's payments over the same period would have been approximately $14,916.00 (assuming the current Specific LV Line rate of $526 per km. was charged throughout that period).

Response

No, Hydro cannot confirm the value of $608,831 or the value of $14,916.

Using 1999 billing load for the load for M1 and M3 and assuming that the LV shared line rate of $0.56 would have been billed to Milton for the period May 2002 to April 2006, 48 months, the charges would have been $294,208. For the period May 2006 to December 2007, 20 months, the Shared LV line charges for M1 and M3 was $214,375. The total is $508,583, not $608,831.

If the charges would have been as Specific LV line for the distance of 0.48 km, the charges would have been $17,169, not $14,916, for 68 months at the rate suggested by Milton of $526 per km.

Milton Hydro (MH) INTERROGATORY 6 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Can you confirm that the replacement value of the 5 poles and 200 metres of line is approximately $30,000.00.

Response

A detailed estimate has not been prepared, but it is our opinion that the cost to replace 5 poles and 200 meters of line would be somewhat greater given there would be no economies of scale for a short section of line such as this.

Milton Hydro (MH) INTERROGATORY 7 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Please confirm that the voltage of the M-1 and M-3 feeders is 27.16 kV.

Response

The voltage of the M1 and M3 feeders is 27.6 kV.

Milton Hydro (MH) INTERROGATORY 8 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Please confirm that the Hydro One property on which Palermo TS sits is not part of Hydro One Distribution's service territory.

Response

The Palermo TS site is not part of Hydro One Distribution's service territory.

Milton Hydro (MH) INTERROGATORY 9 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Can you confirm that over the last two years there have been discussions between Milton Hydro and Hydro One with respect to the sale of the .24 km. of M-1 and M-3 feeder lines to Milton Hydro.

Response

Yes, Hydro One has been in discussions with Milton Hydro with respect to the sale of the M1 and M3 feeders.

Milton Hydro (MH) INTERROGATORY 10 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Please confirm that Hydro One bills Milton Hydro for the service provided through feeder lines M-1 and M-3 as Shared LV lines on the basis of Milton Hydro's monthly maximum demand at the delivery points, e.g. the Hydro One property boundary.

Response

Yes, Hydro One bills Milton Shared LV Line charges based on the maximum demand at the delivery points where the ownership of the feeders changed from Hydro One to Milton.

Milton Hydro (MH) INTERROGATORY 11 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Please confirm that the M-1 and M-3 feeders currently, and since they were constructed, serve only Milton Hydro, and that there are no taps off that part of the M-1 and M-3 feeder lines that are on Hydro One Distribution's property.

Response

Confirmed.

Milton Hydro (MH) INTERROGATORY 12 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Please confirm that under Hydro One's current cost allocation and rate design scheme, had the Palermo TS been constructed on a piece of Hydro One's property in Milton Hydro's territory rather than in Oakville Hydro's territory, the service provided to Milton Hydro by the M-1 and M-3 feeders would have been classified as Specific LV Lines and priced accordingly.

Response

If Palermo TS had been built within Milton, and if Hydro One owned feeders coming out of the TS which remained within Milton and supplied solely Milton, then the Hydro One-owned sections of line would have been billed as Specific Line charges.

Milton Hydro (MH) INTERROGATORY 13 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Please confirm that under Hydro One's cost allocation and rate design scheme, it is only the fact that a part of the M-1 and M-3 feeders lie in Oakville Hydro's service territory that leads it to classify the M-1 and M-3 feeders as shared LV lines, notwithstanding the fact that these two feeders are, and always have been, dedicated to Milton Hydro's load.

Response

A section of line is Specific if it is owned by Hydro One, supplies solely one LDC and is within that supplied LDC. Since feeders M1 and M3 don't fulfill those criteria, they don't classify as Specific Line. A line being dedicated does not make it "Specific" for rates purposes. Although Milton is the only customer connected at Palermo TS M1-M3, these feeders are not dedicated to Milton.

Milton Hydro (MH) INTERROGATORY 14 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

Please confirm that the renaming of the LV charges from LV to ST rates, and the establishment of the ST Rate Class to replace the LV rates class (Ex. G, tab 4, sch. 4, pp. 1 - 4) does not change Hydro One's classification of LV lines into Shared LV Lines, Specific LV Lines, and Specific Distribution Lines, and, more particularly, that the classification of the Hydro One owned portions of the M-1 and M-3 feeders referred to above remain Shared LV Lines.

Response

Confirmed. Specific Line would continue to have the criteria described in Exhibit H, Tab 9, Schedule 13, whether it was LV line or will be ST line. Similarly, line that presently is not Specific, therefore is Shared, will not be Specific and will be Common Line in ST.

Milton Hydro (MH) INTERROGATORY 15 List 1

Interrogatory

Issue 7.1 and Issue 7.2
Issue: Cost Allocation and Rate Design

The Board noted at p. 10, paragraph 2.04 of its Decision with Reasons in RP-2000-0023/EB-2001-0016, that Hydro One stated in its evidence that it would be filing a LV cost allocation study in its next rates application. Was such a study ever prepared? If so, can Hydro One please provide a copy.

Response

The Cost Allocation Study filed in this submission as Attachment A to Exhibit G2, Tab 1, Schedule 1, is Hydro One's response to the OEB's directive in RP-2000-0023/EB-2001-0016. The proposed ST class includes all the LV customers.

Consumers Council of Canada (CCC) INTERROGATORY #1 List 1

Interrogatory

Administration

1. A/T12/S1

HON's rates were reviewed and approved by the Board in its 2006 cost of service rate proceeding. 2007 rates were set using the Board's formula. Please provide a detailed list of any further policy changes, methodological changes, or other changes made by HON in developing rates for 2008 relative to 2006 and 2007 in addition to those set out in this exhibit.

Response

Hydro One is using the OEB recommended cost allocation model, modified as described in Exhibit G2, Tab 1, Schedule 1, to determine revenue requirement by customer class.

Hydro One is proposing 12 new customer classes, as described in Exhibit G1, Tab 2, Schedule 3.

Hydro One is proposing to harmonize the rates of the Acquired LDCs and Legacy customers, as described in Exhibit G1, Tab 2, Schedule 5.

The proposal with respect to Low Use Secondary customers is described in Exhibit G1, Tab 2, Schedule 6.

Hydro One is proposing revenue to cost ratios for the 12 new customer classes consistent with OEB guidelines, as described in Exhibit G1, Tab 3, Schedule 1.

Hydro One is proposing fixed charges consistent with the results of the OEB Cost Allocation methodology, as described in Exhibit G1, Tab 4, Schedule 2.

Hydro One's proposal with respect to rates for the new ST class is described in Exhibit G1, Tab 4, Schedule 4.

Hydro One's proposal with respect to Unmetered Scattered Load rate design is described in Exhibit G1, Tab 4, Schedule 5.

Hydro One's proposal with respect to Transformer Ownership Allowance is described in Exhibit G1, Tab 4, Schedule 6.

Hydro One is proposing Regulatory Rate rider # 3, as described in Exhibit G1, Tab 5, Schedules 1 to 3.

Hydro One is proposing Retail Transmission Service rates as described in Exhibit G1, Tab 6.

Hydro One is proposing to phase-in the target rates over a 4 year period and limit bill impacts as described in Exhibit G1, Tab 8.

Hydro One's proposal with respect to Interim time-of-use rates is described in Exhibit G1, Tab 9, Schedule 1.

Hydro One's proposal with respect to loss factors is described in Exhibit G1, Tab 10.

Consumers Council of Canada (CCC) INTERROGATORY #2 List 1

Interrogatory

Administration

2 A/T8/S3

With respect to HON's Affiliate Services Agreements please provide a list of all changes made since the 2006 distribution rates proceeding. Please indicate the reason for the change and the impact on the distribution OM&A costs and capital costs for 2008.

Response

There have been no changes in the nature of Hydro One Networks' Affiliate Services Agreements since the 2006 Distribution rates proceeding. There have been changes in costs transferred to the affiliates due to changes in budgets and service levels as shown in Exhibit A/Tab 8/Schedule 3. There is no impact on the Distribution OM&A and capital costs for 2008 as the Distribution costs shown in the evidence are net of the costs transferred to affiliates.

Consumers Council of Canada (CCC) INTERROGATORY #3 List 1

Interrogatory

Load Forecast

3 A/T14/S3

The evidence states that the load forecast methodology described is "similar" to the one used in the 2006 rates case. Please specifically identify what has changed and the rationale. Please explain how those changes may have impacted the results.

Response

Please see the response provided in Exhibit H, Tab 1, Schedule 102, part (b).

Consumers Council of Canada (CCC) INTERROGATORY #4 List 1

Interrogatory

Load Forecast

4 A/T14/S3/p. 8

Please provide all of the quantitative analysis used to derive the CDM impacts on HON's load. How, specifically, did HON forecast the CDM impacts for 2008 from the following?: improved building codes and more stringent efficiency standards; conservation programs to encourage more efficient use of lighting and appliances; demand response programs to reduce air conditioning and water heating; smart metering and time of use rates; and programs to increase load supply or reduce demand for large industrial customers.

Response

For a detailed analysis of CDM impacts, please see Attachment A in Exhibit H, Tab 1, Schedule 105. For 2008 CDM impacts, Hydro One used the CDM forecast provided by the OPA consistent with the IPSP that was filed with the Board on August 29, 2007. At the time when Hydro One Distribution forecasted the 2008 CDM impacts, detailed 2008 programs were not yet available. However, Hydro One Distribution assumed the OPA programs will cover all appropriate areas, including improved building codes and more stringent efficiency standards; conservation programs to encourage more efficient use of lighting and appliances; demand response programs to reduce air conditioning and water heating; smart metering and time of use rates; and programs to increase load supply or reduce demand for large industrial customers. For the latest information on 2008 CDM programs, please see the response provided in Exhibit H, Tab 2, Schedule 8.

Consumers Council of Canada (CCC) INTERROGATORY #5 List 1

Interrogatory

Load Forecast

5 A/T14/S3/p. 8

The evidence states that HON does not have the data required to do a bottom-up analysis of the CDM impact on HON's load forecast from the various CDM programs of the OPA, the Provincial Government and federal Government. What is HON doing to acquire the data? In the absence of any such data why should the Board have confidence in the adjustment?

Response

Hydro One Distribution has completed a detailed study examining the load impact of various CDM programs. Please see Attachment A provided in Exhibit H, Tab 1, Schedule 105.

Consumers Council of Canada (CCC) INTERROGATORY #6 List 1

Interrogatory

Load Forecast

6 A/T14/S3/p. 10

The evidence states that customer growth in 2007 and 2008 is expected be 9,400 and 9,500 respectively. This compares to 12,000 which represents the average for the period 2002-2006. Please provide the actual number of customer additions in 2007. Please provide a detailed explanation as to how the 9,400 and 9,500 were derived.

Response

Revised customer additions filed on December 18, 2008 are 11,000 and 9,400 respectively for 2007 and 2008 (2007 customer growth includes an addition of 1,100 customers from Terrace Bay). The actual number of customer additions in 2007 is estimated to be about 11,750 based on information currently available.

Hydro One customer additions forecast is derived using the Ontario housing starts forecast net of demolitions and then prorated by the historical provincial share of new customers for Hydro One Retail. The Ontario housing starts forecast is based on the consensus forecast using inputs from major forecasting firms and financial institutions.

Consumers Council of Canada (CCC) INTERROGATORY #7 List 1

Interrogatory

Distribution Loss Factors

7 A/T15/S3/p. 5

The total energy loss in HON's distribution system is estimate to be about 5.26% of energy sales. The evidence states that this is in line with typical losses incurred by other utilities. Please provide evidence to support this conclusion.

Response

The Kinectric's update report (ref. Exhibit A, Tab 15, Schedule 3 Attachment A) states that the best estimate of the annual energy technical loss in Hydro One distribution systems is 5.3% which is in line with typical losses incurred by other rural utilities.

As identified in Exhibit A, Tab 15, Schedule 3 pp 4, typical rural area losses are 7.3 percent, on average, of energy sold and can range from 4 percent to 10 percent. This is based on a 2005 Canadian Electrical Association (CEA) Technologies Inc. study on the energy efficiency of distribution utilities.

Consumers Council of Canada (CCC) INTERROGATORY #8 List 1

Interrogatory

8 A/T15/S3/p. 5

The evidences states that the Kinetrics study has identified loss reductions to be about $6.5 million. Has this been accounted for in the 2008 revenue requirement? If not, why not?

Response

It is Hydro One's understanding that the question refers to Exhibit A, Tab 15, Schedule 3 p.12.

We take this opportunity to restate and clarify the evidence on line 28 of Exhibit A, Tab 15, Schedule 3 p.12 as follows: "The updated Kinectrics' study identified economic loss reductions costing about $6.5 million."

Hydro One is in the process of completing a distribution network loss reduction program guided by the Kinectrics studies, as discussed in the interrogatory response at Exhibit H, Tab 1, Schedule 97. The cost of this program does not impact Hydro One's 2008 revenue requirement as the program is entirely funded by the Conservation and Demand Management program approved in a prior year.

Consumers Council of Canada (CCC) INTERROGATORY #9 List 1

Interrogatory

9 A/T14/S2/pp. 4-5

The 2007 and 2008 forecast debt rates and deemed debt rates differ. What rates are used for rate-setting purposes?

Response

Hydro One Distribution's capital structure for rate-setting purposes includes both third-party debt and deemed debt, as shown in Exhibit B1-1-1.

Forecast debt rates are used to cost third-party long-term debt (see Exhibit B2-1-2), while forecast deemed debt rates are used to cost deemed long and short-term debt.

Consumers Council of Canada (CCC) INTERROGATORY #10 List 1

Interrogatory

Cost of Service

OM&A

10 1/T2/S1/p. 2

OM&A expenditures have grown by $74 million from 2006 to 2008. Please provide a detailed breakdown of that amount, specifically identifying the major cost drivers.

Response

A detailed breakdown of OM&A expenditures is found in Exhibit C2, Tab 2, Schedule 1.

The drivers for the $74 million increase from 2006 to 2008 are:

1) $30.3 million increase in Vegetation Management as discussed in Exhibit C1, Tab 2, Schedule 2, beginning on page 29. This increase is driven by Hydro One's need to increase efforts to manage vegetation growth.

2) $45.7 million increase in Shared Services and Other Costs that are driven predominantly by:
   a. $5.4 million increase in Common Asset Management Costs for the reasons discussed on page 39 of Exhibit C1, Tab 2, Schedule 6.
   b. $7.3 million in Common Corporate Costs for the reasons discussed on page 6 of Exhibit C1, Tab 2, Schedule 6.
   c. $12.1 million in Overheads Recovered on Capex as discussed on page 81 of Exhibit C1, Tab 2, Schedule 6.
   d. $10.9 million in Other related to the Deferred Pension Cost as discussed on page 83 of Exhibit C1, Tab 2, Schedule 6.

Other Sustaining, Development, Operations, Customer Care, and Shared Services and Other Costs programs have varied between the years but are not as significant a driver as those stated above.

Consumers Council of Canada (CCC) INTERROGATORY #11 List 1

Interrogatory

Cost of Service

OM&A

11 1/T2/S2/p.30

Please provide a business case for the 2008 vegetation management program.

Response

Hydro One Distribution does not prepare business cases for ongoing routine maintenance programs such as vegetation management. Additional information concerning the justification for this program is provided in the interrogatory response at Exhibit H, Tab 1, Schedule 49.

Consumers Council of Canada (CCC) INTERROGATORY #12 List 1

Interrogatory

Cost of Service

OM&A

12 1/T2/S2/p. 23

Please provide a detailed budget for Miscellaneous Service. Please include 2006 historical and actual numbers.

Response

Miscellaneous Services can be broken out into two subsets. The details are below.

Cost Subset	2006	2007	2008 Test
Environmental Health & Safety	0.7	1.5	2.1
Miscellaneous Services (Other)	2.5	4.7	2.8
Total – Miscellaneous Services	**3.2**	**6.2***	**4.9**

* As discussed in the interrogatory response at Exhibit H, Tab 13, Schedule 4, part e, this figure is a correction to the evidence in Table 7 of Exhibit C1, Tab 2, Schedule 2 updated February 20, 2008.

Further details of activities contained in each subset in the table above can be found in Exhibit C1, Tab 2, Schedule 2, page 23.

Consumers Council of Canada (CCC) INTERROGATORY #13 List 1

Interrogatory

Cost of Service

OM&A

13 1/T2/S5/p. 4

Customer Care Base Services are increasing by $3.8 million in 2008 due to a decline in base fees offset by growth in annual volumes, annual COLA amounts and changes in the scope of services. Please specifically identify the changes in scope and the costs associated with those changes for 2008.

Response

The Customer Care Base Services cost increase of $3.8 million in 2008 over 2007 is only partially due to "a decline in base fees offset by growth in annual volumes, annual COLA amounts and changes in the scope of services". These factors apply to the Customer Service Operations portion of the Base Services Cost total which represents a $1.2M increase in 2008 over 2007.

The remainder of the $3.8M increase applies to increases in

- Other Field Support Costs ($1.1M) primarily due to increased collections activity in the field (disconnects/reconnects)
- Other Service Support Costs increase by $1.1M mainly due to increased collection agency fees, other collections related activity, and an increase in expected telephone costs. (see interrogatory Exhibit H, Tab 13, Schedule 16)
- Customer Care Management costs increase by $900K (see interrogatory Exhibit H, Tab 1, Schedule 66)

- These cost increases are offset by a $300K decline in the meter reading costs

Consumers Council of Canada (CCC) INTERROGATORY #14 List 1

Interrogatory

Cost of Service

OM&A

14 1/2/S5/p. 12

Please provide a schedule which sets out bad debt expenses for the period 2000 to 2007. Please include, for each year, budgeted and actual bad debt expense.

Response

Please find below a schedule for budgeted and actual bad debt expense from 2002 to 2007.

Year	2002		2003		2004		2005		2006		2007	
($M)	Budget	Act	Budget	Act	Budget	Act	Budget	Act	Budget	Act	Budget	Act
Net Bad Debt	5.3	9.7	10.0	13.6	7.9	11.8	10.0	9.7	10.4	17.3	13.6	13.5

Consumers Council of Canada (CCC) INTERROGATORY #15 List 1

Interrogatory

Cost of Service

OM&A

15 1/2/S5/p. 3

Regulatory compliance costs are increasing by $2.9 million in 2008 over 2007. Please provide a detailed breakdown of the $3.6 million budget for 2008.

Response

The table below provides the list of Regulatory Compliance initiatives for 2008.

Regulatory Compliance Projects	2008
2008 Dx Rate Cost Allocation & Rate Design	2.4
Semi-annual RPP Commodity Price & Seasonal Threshold Changes	0.5
Miscellaneous Regulatory Compliance Projects	0.7
TOTAL - Regulatory Compliance Projects	**3.6**

Consumers Council of Canada (CCC) INTERROGATORY #16 List 1

Interrogatory

Cost of Service

OM&A

16 2/T2/S1/pp. 1-2

Please provide a schedule in the same format as "Comparison of OM&A Expense by Major Category" which includes 2006 and 2007 Board approved numbers.

Response

The OEB approved the 2006 OM&A expense total of $423.1 million that was filed in Exhibit C2, Tab 2, Schedule 1 of EB-2005-0378. The 2006 OM&A amounts from that Exhibit have been included below. 2007 amounts have not been included since the OEB did not approve any specific program costs as rates were adjusted using the 2nd Generation Incentive Regulation adjustment mechanism.

	2006
Distribution OM&A ($ millions)	
Sustaining	
Distribution Lines Maintenance	
Trouble Call, Cable Locates and Connect/Re-connect	68.2
Line Maintenance	26.3
PCB Testing & Waste Management	2.8
Other Services	8.8
Total Lines OM&A	106.1
Stations OM&A	
Planned Maintenance	10.9
Demand and Corrective	5.4
Land Assessment & Remediation	5.2
Total Stations OM&A	21.5

	2006
Metering OM&A	
Customer Retail Meters	7.2
Wholesale Meters	1.6
Total Metering OM&A	8.8
Forestry OM&A	
Customer Notification	7.3
Line Clearing	60.1
Brush Control	20.5
Demand Work	5.5
Asset Condition Assessment	0.5
Total Forestry OM&A	93.9
Total "Sustaining"	230.3
Development	4.9
Operations	
Operating Support	3.8
Operators	10.5
Total "Operations"	14.3
Customer Care	
Base Services	81.2
Bad Debt	10.4
Regulatory Compliance	4.5
Service Enhancements	5.0
Total Customer Care	101.1

	2006
Shared Services and Other Costs	
Common Asset Management Costs	39.3
Common Corporate Costs	35.5
Information Management Services	38.0
Business Telecom	7.4
Cost of Sales	7.0
Overheads Recovered on Capex	(48.4)
Environmental Provision Credits	(8.1)
Indirect Depreciation Embedded in Rates	(11.6)
Deferred Pension Costs	0.0
Other	8.8
Total Shared Services and Other Costs	67.9
Property Taxes & Rights Payments	4.6
Total Distribution OM&A	**423.1**

1

Consumers Council of Canada (CCC) INTERROGATORY #17 List 1

Interrogatory

Cost of Service

OM&A

17 2/T2/S1

Has HON done an OM&A forecast for the period 2009 and 2010? If so, please provide that detailed budget in the same format.

Response

The 2009 and 2010 forecast levels are beyond the scope of this proceeding; in addition, work plans for beyond 2008 are currently under development.

Consumers Council of Canada (CCC) INTERROGATORY #18 List 1

Interrogatory

Cost of Service

Human Resource Costs

18 2/T3/S1

For each of the three Tables provided in this Exhibit please provide the forecast numbers for 2006 and 2007.

Response

The tables originally submitted contain 2007 forecast numbers whereas the 2004 to 2006 numbers are actuals. No 2006 forecast numbers are available as the EB-2005-0378 values were prepared on a different basis.

Table 1
Regional Maintainer Lines (PWU-Represented)

Year	Total Wages	Base	Overtime	Incentive	Other*
2004	$98,822	$67,987	$26,377	$2,483	$1,975
2005	$102,325	$70,208	$29,186	$760	$2,170
2006	$111,439	$74,117	$34,639	$0	$2,683
2007	$114,782	$76,340	$35,679	$0	$2,764
2008	$118,226	$78,630	$36,749	$0	$2,847

NOTE: all of the above are average dollars.

* Other includes: travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination, depending on the nature of the position.

Table 2
Society Represented MP4 (Example: Engineer – Journeyperson Level)
Annual Salary

Year	Total Wages	Base	Overtime	Incentive	Other*
2004	$96,423	$85,578	$8,028	$0	$2,817
2005	$69,200	$62,420	$3,125	$0	$3,656
2006	$95,524	$92,564	$1,207	$0	$1,753
2007	$98,390	$95,341	$1,243	$0	$1,806
2008	$101,342	$98,202	$1,281	$0	$1,860

NOTE: 2005 results are lower due to the impact of the labour strike.
NOTE: all of the above are average dollars.
* Other includes: travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination, depending on the nature of the position.

Table 3
Manager – Band 7 (Management Compensation Plan)
Annual Salary

Year	Total Wages	Base	Overtime	Incentive	Other*
2004	$107,813	$90,068	$423	$11,620	$5,702
2005	$107,938	$89,136	$1,187	$7,806	$9,808
2006	$114,332	$96,066	$222	$3,139	$14,905
2007	$117,762	$98,948	$0	$11,200	$7,615
2008	$121,295	$101,916	$0	$11,600	$7,779

NOTE: all of the above are average dollars.
* Other includes: travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination, depending on the nature of the position.

Consumers Council of Canada (CCC) INTERROGATORY #19 List 1

Interrogatory

Cost of Service

Human Resource Costs

19 /T14/S1/p. 3

For all MCP employees HON has assumed an annual increase of 4% per year in base pay for the "entire period". How was the 4% level derived? (Exhibit A/T14/S2 states that the escalation factors were provided by HON senior management) What is the "entire period"? What is the range of increases assumed for the MCP group for 2008? What has been used to develop the forecast of labour expenses?

Response

The MCP increase of 4% was used for the business planning period of 2008-2012. The actual amount of base pay allotted for MCP staff is approved annually by the H1 Board of Directors and is never applied as an "across the board" economic increase but rather as a reflection of an employee's increased competency in a job. MCP jobs are broad banded which allow for and recognize a range of competency levels and pay levels within a band. Annual base pay adjustments can range from 0% to any percent which does not take an individual above the top end of his/her pay band. The amount used by the corporation in total cannot exceed the amount approved by the Hydro One Board for that year's annual base pay allocation.

Consumers Council of Canada (CCC) INTERROGATORY #20 List 1

Interrogatory

Cost of Service

CDM

20 /T13/S1/p. 8

Please confirm that beyond April 30, 2008, HON will only be undertaking CDM programs through the OPA funded framework. Are there any costs included in the 2008 revenue requirement related to CDM? If so, please identify where those costs are accounted for.

Response

It is HONI's intent to seek funding for CDM funding primarily via the OPA funded framework. HONI has included $1M in the 2008 revenue requirement within the Other Shared Services – Other category to sustain existing CDM programs and maintain a minimum capability. HONI also requires an additional $800,000 to close off the programs initiated under MARR funding.

Consumers Council of Canada (CCC) INTERROGATORY #21 List 1

Interrogatory

Cost of Service

Rate Base

21 /T3/S1/p. 12

The evidence states that, "Substantial new generation appears likely to connect to Hydro One's distribution system over the next few years." HON has indicated that this will lead to an expanded scope for distribution system planning going forward. Please expand on the challenges HON is facing regarding new generation connections. What are the potential cost impacts going forward? Specifically, how is HON expanding the scope for distribution system planning? How does this impact the 2008 revenue requirement?

Response

HON is facing a number of challenges with respect to new generation connections to its distribution system (and the flow through impact on Hydro One's transmission and/or distribution systems from new generators connecting to other LDC systems). The most significant challenges stem from the volume of potential new projects, and the uncertainty with respect to which projects will actually move forward to actually connect to the system.

From the start of 2006 to February, 2008, Hydro One received more than 1800 applications for either Initial Feasibility Assessments or full Connection Impact Assessments (CIA) of potential new generation connections. Of these, we received applications for CIAs on 818 projects connecting to Hydro One's system, plus 84 projects connecting to LDC's which might impact Hydro One's system. Of these, 394 projects connecting to Hydro One (plus 54 connecting to LDC's) are within the thresholds Hydro One established to determine those projects that might technically be able to connect and thus should be assessed. For those projects within threshold, to the end of February, 2008, Hydro One had done 367 CIAs for 271 projects connecting to Hydro One (the higher number of assessments is related to situations where projects changed their parameters and required a revised assessment to be done), plus 34 CIAs for 34 projects connecting to LDCs.

Of the projects connecting to Hydro One's distribution system that have been assessed, 62 have signed Connection and Cost Recovery Agreements indicating an intent to proceed to connection. However, of these, several projects have not yet established

expected connection dates and/or are not working with Hydro One on the details of their connection. As well, it is uncertain how many other projects will move to sign CCRAs and will expect to be connected, and if they do, when they might wish to be connected. As such, the number of generators that will actually connect is difficult to forecast.

As noted in Exhibit A, Tab 3, Schedule 1 (page 12), under the current Distribution System Code, generators are connected on a user pay basis and Hydro One is not proactively developing the distribution system to accommodate potential new generation. As such, the cost impacts included in this rate filing for 2008 are quite limited and are set out in the submission. Net OM&A costs are expended to carry out IFAs, to do studies of feeders in preparation for the potential need to connect substantial new generation, to do some limited technical studies as noted below, and to address the multitude of general policy questions that have been raised by the extensive number of projects investigating connection. Net Capital costs are as outlined in the responses to OEB Staff Interrogatories Exhibit H, Tab 1, Schedule 24 and Exhibit H, Tab 1, Schedule 26. The upcoming Distribution Cost Connection Responsibility Review initiated by the Board may result in some changes to this.

However, even under the user pay paradigm, there are a multitude of issues that need to be addressed to provide the maximum access for new generators consistent with maintaining ongoing reliable supply to all customers. The general challenges faced by HON are outlined in the referenced section. More particularly, HONI has launched a number of relatively limited studies on such topics as:

- Reverse flow impact
- Impact of generation relative to load
- Impacts of location of generators
- Low cost protection systems
- Anti-islanding studies to determine need for protections
- Technical parameters for planning to ensure reliability is maintained

As indicated by the nature of the studies noted above, the scope for distribution planning is increasing due to the potential for new generation connections resulting in a need for more complex and detailed planning studies to ensure customer service quality is not compromised. The planning studies must also include more detailed analysis of operational and safety issues associated with the connection of dispersed generation.

While there is increased scope of distribution planning incorporated in this submission, the associated costs in the submission are limited. This is based on an understanding that the Standard Offer Program is based on an expectation that any investment in the system needed to incorporate the new generators will be paid for by the new generators. This puts an economic limit on the need for major new distribution system investments. There is a possibility that investment in distribution may need to be substantially increased to

provide for higher levels of new connected generation, but this is not currently the basis for Hydro One planning.

Consumers Council of Canada (CCC) INTERROGATORY #22 List 1

Interrogatory

Cost of Service

Rate Base

22 2/T2/S1

With respect to the "Comparison of Capital Expenditures" please provide Board approved amounts for 2006.

Response

Please see Interrogatory response Exhibit H, Tab 1, Schedule 40.

Consumers Council of Canada (CCC) INTERROGATORY #23 List 1

Interrogatory

Cost of Service

Rate Base

23 1/T3/S5/pp. 16-21

The Cornerstone Project was presented for approval in HON's most recent transmission case. Please identify any changes in cost or scope associated with Phase I of the project. The evidence states that, "Included in 2008 are project start up and initiation costs for subsequent phases." Please identify the cost components included in the 2008 capital budget that are related to the subsequent Phases.

Response

a) There are no material changes in cost or scope associated with Phase 1 of Cornerstone between Hydro One's most recent Transmission rate case and this application.

b) Capital cost components in 2008 for the subsequent phases of Cornerstone are:

Cornerstone Phase 2	$3.6 M
Cornerstone Phase 3	$9.0 M
Cornerstone Phase 4	$0.0 M

Consumers Council of Canada (CCC) INTERROGATORY #24 List 1

Interrogatory

Cost of Service

Rate Base

24 1/T3/S5/p. 19

The evidence states that HON commenced with Phase I of the Cornerstone Project after obtaining HON Board approval in February 2007. Please provide copies of all materials/presentations etc. that were provided to the HON Board as part of the Cornerstone Project approval process.

Response

Hydro One declines the request to provide the material and/or presentations made to the Hydro One Board as part of the approval process on the Cornerstone project. Material and/or presentations to the Hydro One Board are confidential in nature and not otherwise disclosable. Information contained in such material is commercially sensitive, involves third parties and would refer to third party information provided in confidence to Hydro One. Such material would not be provided under Freedom of Information and Protection of Privacy legislation as it would be exempt from disclosure.

Consumers Council of Canada (CCC) INTERROGATORY #25 List 1

Interrogatory

Cost of Service

Rate Base

25 /T10/S2

In the Management's Discussion and Analysis provided in the quarterly reports for 2007 it states that Distribution Revenues increased by $109 million, or 3% in 2007. Please provide a schedule which sets out the components of HON's revenue for the years 2006-2010 (forecast where appropriate). Please provide a variance account for each of those years and any assumptions used in the forecast numbers.

Response

The components of HON's revenues for the years 2006 to 2008 are as follows (2009 and 2010 excluded as they are out of scope):

	Actual 2006 M$	Actual 2007 M$	Forecast 2008 M$
Dx Tariff	786	872	901
COP Flow Through	1,954	1,964	1,959
RRRP	125	125	125
External	41	44	42
Total HON Dx Revenues	**2,906**	**3,005**	**3,027**

Note the increase of $109M as noted in the MD&A includes Hydro One Brampton and Hydro One Remotes.

RSVA variance accounts included in the above are -$19M for 2006, -$39M for 2007 and $14M for 2008.

The forecast for 2008 was based on assumptions consistent with those utilized for the revenue requirement.

Consumers Council of Canada (CCC) INTERROGATORY #26 List 1

Interrogatory

Cost of Service

External Revenues

26 3/T2/S1/p. 1

Please provide the 2006 Board approved amount for each component of "External Revenues".

Response

See table below.

1

External Revenues Historic, Bridge Year and Test Year
Hydro One Networks Inc.

million $'s

	2004	2005	2006	2006 Board Approved	2007	2008
Regulated Revenues						
Joint Use Revenue	**5.3**	**5.6**	**5.8**	**5.5**	**6.0**	**6.2**
Telecommunications	5.1	5.4	5.6	5.3	5.8	6.0
Street Lighting	0.2	0.2	0.2	0.2	0.2	0.2
Sentinel Revenue*	**4.9**	**3.5**	**3.6**	**3.6**	**3.3**	**4.0**
Retail Service Revenue	**N/A**	**N/A**	**N/A**	**N/A**	**0.9**	**1.1**
Miscellaneous Charges	**16.3**	**15.2**	**17.2**	**18.4**	**19.7**	**20.0**
Late Payment Charges	11.1	11.8	12.4	13.5	14.2	14.5
Other Miscellaneous Charges	5.2	3.4	4.8	4.9	5.5	5.5
Total Regulated	26.5	24.3	26.6	27.5	29.9	31.3
Unregulated Revenues						
Joint Use Revenue	**2.5**	**2.2**	**3.2**	**3.2**	**3.3**	**3.3**
Bell Canada	2.2	2.2	3.0	3.0	3.0	3.0
LDC's	0.3	0.0	0.2	0.2	0.3	0.3
DX Generation Studies	**0.1**	**0.1**	**0.7**	**0.1**	**1.5**	**0.5**
New Connects/Upgrades & Other Contestable Work	**28.6**	**15.1**	**6.7**	**8.1**	**7.9**	**6.2**
New Connects & Upgrades	5.3	5.2	4.3	5.0	4.9	4.0
Lines - Other Contestable Work	22.3	8.9	1.1	2.0	2.0	1.0
Forestry Contestable Work	0.0	0.0	0.1	0.1	0.0	0.1
Health, Safety & Environment Training	1.0	1.0	1.2	1.0	1.1	1.1
Non-Regulated Miscellaneous Revenue	**1.0**	**0.6**	**0.9**	**0.9**	**0.8**	**0.7**
Total Unregulated	32.2	18.0	11.6	12.3	13.5	10.7
Total External Revenue	**58.7**	**42.3**	**38.1**	**39.8**	**43.3**	**42.0**

*** Sentinel** Revenue in 2004 was excluded from the regulated Distribution business, Exhibit A, Tab 5, Schedule 1

2

Consumers Council of Canada (CCC) INTERROGATORY #27 List 1

Interrogatory

Cost of Service

Smart Meters

27 /T10/S2/p. 14

The evidence states that HON is piloting the "Smart Network" initiative. Please provide a comprehensive description of this initiative and provide the costs for 2008.

Response

A high level cost benefit analysis was undertaken at the beginning of the smart meter program (2005) and was used as the basis of determining system and communication architecture. The analysis concluded that given Hydro One's demographics and geography and needs for a ubiquitous communications network it should consider procuring and installing a system capable of supporting applications beyond just smart meters (such as two-way communications for CDM devices in the home, distribution SCADA and real-time outage management, and potentially new initiatives like distributed generation).

As part of its assessment, Hydro One requested the RFP selected vendors to provide a proof of concept to demonstrate that in fact the systems could support these additional requirements. In 2005 and 2006 a Smart Network demonstration site was built and tested near Barrie Ontario. The Smart Network essentially extends the current fibre system using an open standard broadband wireless application better known as WiMax (IEEE 802.16 standard). In addition Hydro One began two-way communications with a smart meter pilot area (as part of the first phase of the smart meter program), a distribution station (SCADA) remote terminal unit, an in station security system (controllable security camera) and demonstrated mobile IT (leveraging it automated change meter order process developed for mass smart meter deployment) and finally two way in-home CDM devices (in-home display).

For 2008 we plan to continue to monitor the site and are planning only minor extensions to research the smart networks ability to support distributed generation (transfer trip) and distribution automation (automated reclosures). The cost of this extension is budgeted at less than $1 million.

Consumers Council of Canada (CCC) INTERROGATORY #28 List 1

Interrogatory

Cost of Service

Smart Meters

28 1/T1/S1p. 5

Please provide the following information regarding HON's smart meter program:

1. A detailed breakdown of all smart meter expenditures incurred to December 31, 2006 (capital and operating costs).

2. A detailed breakdown of all smart meter expenditures incurred to December 31, 2007 (capital and operating costs).

3. A detailed breakdown of all smart meter expenditures (actual and forecast) for the period January 1, 2008 to April 30, 2008.

4. For each of the periods listed above the revenue recovered from HON's customers through the rate riders related to smart meter costs.

5. For 2008 a detailed breakdown of all smart meter costs (capital and operating costs) Please specifically identify all costs that meet minimum functionality and all costs that exceed minimum functionality.

6. A forecast of smart meter costs expected for 2009. This should include all one-time costs and ongoing annual costs.

Response

1.-5. The following tables provide the detailed breakdown of smart meter expenditures and revenue recovered.

Revenue

$ Thousands	2006 ACTUAL	2007 ACTUAL	2008 April 30th	2008 Budget
Recover through Smart Meter Rider	2,500	10,000	4,400	-

OM&A Smart Meter Costs

$ Thousands	2006 ACTUAL	2007 ACTUAL	2008 April 30th	2008 Budget
OM&A Cost for Minimum Functionality				
2.1 Advanced Metering Communication Device (AMCD)	1,005	1,626	924	2,019
2.2 Advanced Metering Regional Collector (AMRC) (includes LAN)	0	79	0	0
2.3 Advanced Metering Control Computer (AMCC)	24	765	711	811
2.4 Wide Area Network (WAN)	1	764	72	764
2.5 Other AMI OM&A Costs Related to Minimum Functionality	3,711	2,979	896	2,189
OM&A Cost for Minimum Functionality	4,741	6,212	2,603	5,783
OM&A Cost for Exceeding Minimum Functionality	163	0	0	3,917
OM& A Sub Total	4,904	6,212	2,603	9,700
LESS CDM Funding	881	0	0	0
Total OMA	4,023	6,212	2,603	9,700

Capital - Smart Meter Costs

$ Thousands	2006 ACTUAL	2007 ACTUAL	2008 April 30th	2008 Budget
Capital Costs for Minimum Functionality				
1.1 Advanced Metering Communication Devices (AMCD)	9,984	51,494	18,822	77,933
1.2 Advanced Metering Regional Collector (AMRC) (includes LAN)	0	5,052	2,846	11,254
1.3 Advanced Metering Control Computer (AMCC)	950	3,144	1,891	6,333
1.4 Wide Area Network (WAN)	0	22	0	0
1.5 Other AMI Capital Costs Related To Minimum Functionality	879	4,459	2,645	40,986
Sub Total Capital Cost for Minimum Functionality	11,813	64,171	26,204	136,506
Less CDM Funding	6,400			
Total Capital Cost for Minimum Functionality	5,413			
Costs for Functions Exceeding Minimum Functionality				
Meter Outage Detection Capability	182	3,712	2,464	5,750
Collector Outage Detection Capability	0	403	1,742	1,479
Wimax	968	0	0	0
TOU Capability	1,035	4,639	3,620	12,563
Integration and Transaction Management	70	3,780	1,856	8,505
Total Costs for Functions Exceeding Minimum Functionality	2,255	12,534	9,683	28,297
TOTAL SMART METER COSTS	7,667	76,705	35,887	164,803

6. Recovery of costs beyond 2008 is not being requested as part of this hearing.

Consumers Council of Canada (CCC) INTERROGATORY #29 List 1

Interrogatory

Cost of Service

Smart Meters

29 2/T2/S1/p. 1 and C2/T2/S1

The total capital expenditures related to smart meters for 2008 is $164.8 million. The total OM&A costs are $9.7 million. Please provide a detailed breakdown of these amounts. Does this include all smart meter expenditures for 2008. If not, please identify where the other costs are accounted for.

Response

Please see the IR response in Exhibit H, Tab 10, Schedule 28. The totals in this IR response include all smart meter expenditures for 2008.

Consumers Council of Canada (CCC) INTERROGATORY #30 List 1

Interrogatory

Cost of Service

Smart Meters

30 2/T2/S1/p. 1 and C2/T2/S1

With respect to HON smart meter costs for 2008 ($164.8 million in capital and $9.7 million in OM&A) is HON proposing variance account treatment to ensure only actual costs are recovered from customers? If not, why not? If HON spends less than forecast (and recovered through rates) on its smart meter program how will the ratepayers be compensated?

Response

Hydro One is proposing to treat forecast smart meter costs that are included in 2008 rate base and revenue requirement the same as all other forecast rate base and revenue requirement components (ie. no variance account treatment).

However, to the extent that a portion of the 2008 smart meter costs are included in the smart meter regulatory assets Hydro One is proposing to recover as of April 30, 2008, as with Hydro One Distribution's other Regulatory Asset Recovery Accounts, this will require that the balances in these accounts be trued up at a later date to recover/refund the differences between forecast and actual costs.

Consumers Council of Canada (CCC) INTERROGATORY #31 List 1

Interrogatory

Cost of Service

Smart Meters

31 1/T1/S1p. 5

Please provide the number of smart meters installed in 2006 and 2007. Please provide the forecast of the number of meters expected to be installed in 2008. Please provide the number of remaining meters to be installed beyond 2008.

Response

Meters installed in 2006	27,600
Meters installed in 2007	222,831
Meters planned to be installed in 2008	370,000

The plan is to replace all meters by 2010 so approximately 700,000 smart meters are projected to be installed beyond 2008.

Consumers Council of Canada (CCC) INTERROGATORY #32 List 1

Interrogatory

Cost of Service

Smart Meters

32 1/T1/S1p. 5

Please provide a copy of HON's smart meter implementation plan that was filed with the Board in December 2006. Please provide any updated implementation plans, if available.

Response

Attached 1 is Hydro One Networks Smart Meter Investment Plan filed with the Board December 15, 2006

Updated implementation plans have not been developed.

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BY COURIER

December 15, 2006

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Ontario Energy Board
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P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2006-0246 - OEB Smart Meter Filing Requirements – Hydro One Networks Smart Meter Investment Plan

As requested by the Ontario Energy Board in its letter to electricity distribution companies dated October 26, 2006, I am attaching three paper copies of the Hydro One Networks Smart Meter Investment plan.

In addition, a text-searchable Acrobat file will be sent to Boardsec@oeb.gov.on.ca by email today.

Sincerely,

Susan Frank

Susan Frank

Attach.

Hydro One Networks Inc.
Smart Meter Plan
2006 – 2010

Submission to OEB
EB-2006-0246

December 15, 2006

1 Purpose of Submission

In accordance with the Ontario Energy Board's ("the Board") letter of direction dated October 13, 2006, and the subsequent filing guidelines issued on October 26, 2006, Hydro One Networks Inc. ("Hydro One") is pleased to file the Company's smart meter investment plan for the 2006 – 2010 time period.

2 Introduction

The Provincial Government has stated its intention to replace all meters in Ontario with smart meters by 2010. The government has passed regulations authorizing Hydro One to procure smart meters based on its Request for Proposal ("RFP") issued in March of 2005. Further, the regulations permit distributors to recover in rates the cost associated with Smart Meters subject to final approval from the Ontario Energy Board.

The Ontario government's smart meter initiative requires the implementation of 800,000 smart meters by 2007 with full implementation throughout the entire province by 2010. Hydro One's share of the government's smart meter target for 2010 is approximately 1.3 million meters and this smart meter plan is designed to meet the government targets.

Hydro One did not file a specific smart meter investment plan as part of its 2006 EDR rate application. In accordance with the Board's EB-2005-0529 Generic Decision, a $0.30 meter cost per residential customer per month was reflected in Hydro One's revenue requirement. This smart meter revenue was allocated to all metered customers and recovered through their monthly service charges as of May 1, 2006.

On March 17, 2005, the Board approved Hydro One's plan for CDM. In this plan, $7.8 million was allocated to the smart metering program to address initial start-up costs and deployment. In order to meet government smart meter targets Hydro One forecasts that $155 million (inclusive of CDM funding of $7.8 million) in capital and operating expenditures will be required through the end of 2007.

Planned smart meter activities are still at an early stage. The current dynamic state of smart meter and communication technologies, especially with respect to rural applications, will likely change the cost estimates of deployment beyond 2007. Hydro One therefore believes it would be premature to provide a forecast of expenditures beyond 2007 at this time.

3 Background

On June 23, 2004 the Minister of Energy issued a directive to the Ontario Energy Board that establishes targets for the installation of 800,000 smart meters by December 31, 2007 and for all Ontario customers by 2010. Hydro One's share based on its proportionate share of customers in this province is 240,000 by 2007 and approximately 1.3 million by 2010.

In March of 2005 Hydro One undertook an extensive RFP for vendors in the functional areas of smart meters, communications, meter data management and systems integration including changes to its customer information and billing system. Vendor selections were made in April of 2005 and 25,000 meters were procured to begin pilot projects that would allow Hydro One to develop mass deployment processes for its change meter process.

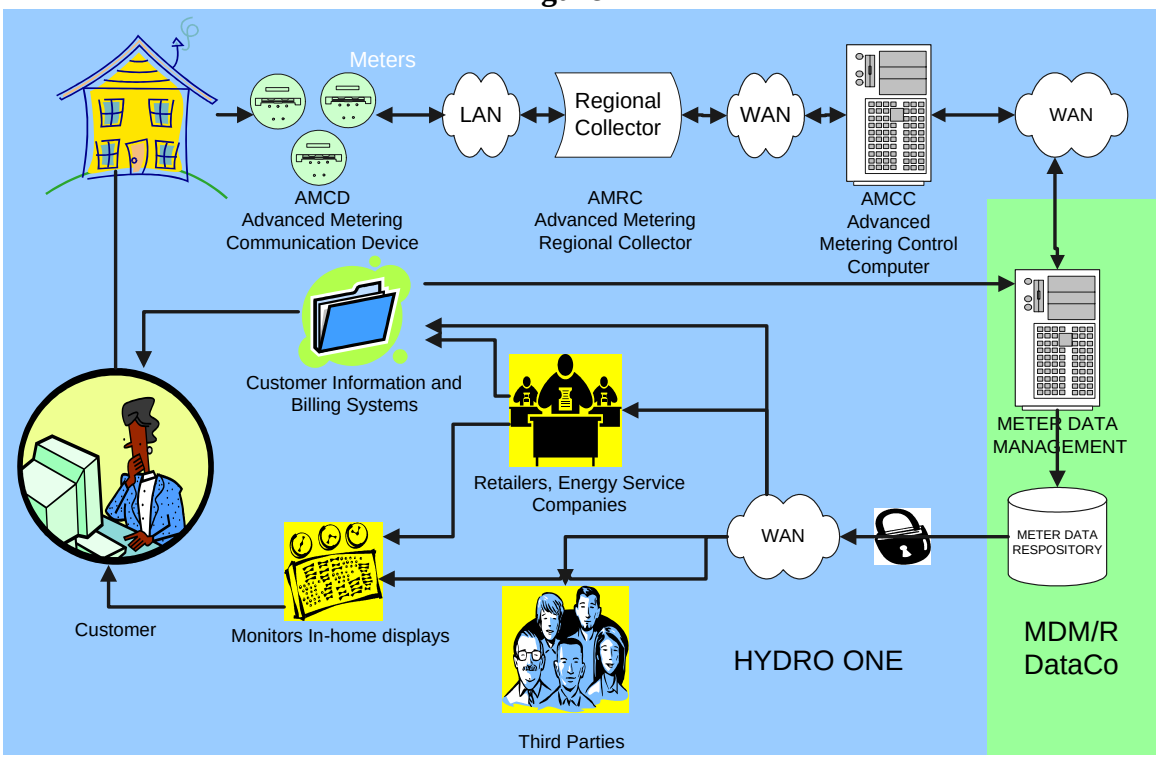
The Province's smart meter initiative was put on hold throughout the remainder of 2005 while roles and responsibilities amongst industry stakeholders were discussed. Regulations issued reduced the role of the distributor by excluding functions associated with meter data management and defined minimum specifications for advanced meter infrastructure. These clarified roles and minimum specifications are the basis for the cost recovery through rates of the smart meet investment.

During 2006 Hydro One was able to pilot its meter install process and automation tools and developed unit costing for mass market deployment. Statements of work and contracts have also been developed with the major vendors selected from the 2005 RFP. This work provides detailed pricing for the majority of the products and services required by Hydro One under this initiative.

4 Smart Meter Infrastructure Requirements

Figure 1 outlines the roles of the various parties who will be involved in the smart meter initiative.

Figure 1



The Independent Electricity System Operator ("IESO") has recently been appointed by the Ontario Ministry of Energy to coordinate the establishment of the metering infrastructure ("DataCo") in cooperation with the province's local distribution companies ("LDCs"). DataCo will be responsible for the collection, management, processing and storage of consumers' consumption information and data received from the LDCs smart metering infrastructure.

Since Hydro One will rely on DataCo to provide the meter data management/repository ("MDM/R") functionality, no costs have been included in Hydro One's plan for this activity. Only expenditures required to interface between MDM/R and Hydro One's customer billing system ("CIS") have been included.

Hydro One will have the accountability to own and install the smart meters, collect customer metering data via a computer application ("AMCC"), pass the data to DataCo's data warehouse, and receive the data back for customer billing purposes. The installed smart meters must report consumption to customers by the next business day and be able to provide the delineation required for time of use billing or other possible pricing plans such as Critical Peak Pricing Plan ("CPP Plan"). To meet the smart meter directive new communications and information technology infrastructure is required to collect and process transactions in a timely manner.

5 Deployment plan

Hydro One's smart meter deployment plan has been developed to ensure the highest long term customer value by identifying up front, a vision and a number of operating principles that will protect the investment from early obsolescence, while at the same time recognizing and balancing the inherent risks associated with new technology and large projects.

The Hydro One vision is:

To deploy a smart metering solution that meets the Ministry of Energy's requirements at the lowest possible cost and is an enabler for other business processes and transformations.

Hydro One has adopted the following Operating Principles:

- Develop and deploy an end to end architecture for both information technology and communications infrastructure that recognizes long term business needs and provides a migration path from the minimum requirements of a smart meter system;
- All hardware and devices will conform to industry standards and will be based on open architecture design (i.e. to the extent possible use non-proprietary applications);
- Material development will not occur until all, including third party, requirements are understood; and

- A staged implementation will be deployed across all work streams to mitigate risk. This includes Advanced Metering Infrastructure (AMI) technology, business process design, systems development and integration and customer communications.

In March of 2005 Hydro One undertook an extensive RFP process to launch its smart meter initiative.

This RFP was an open invitation to provide a combination of professional services, hardware, and software in any or all of the following four solution areas:

- Smart Meters and related "behind the seal" devices;
- Telecommunications to support smart meters and other related initiatives;
- New downstream processing including automatic Meter Reading, Meter Management, Meter Data Warehouse, Customer Presentment, and Calculation of Customer Bill Determinants; and
- Integration to Enterprise Applications (CIS, Accounts Payable, Asset and Work Management).

Proposals were solicited by public advertisement in the Globe & Mail and approximately 200 requested were fielded. Out of these requests, 48 vendors' responses were received by Hydro One. All proposals were evaluated by a 7 members cross-functional team. A number of LDCs were also invited to join Hydro One and to provide input into the evaluation process. The LDCs who participated included Barrie Hydro Distribution Inc., Kitchener-Wilmot Hydro Inc., ENWIN Powerlines Ltd., London Hydro Inc. and Hydro One Brampton Networks Inc..

6 Project Risk and Mitigation

Hydro One's project plan recognized that there are several risks that need to be mitigated and developed an implementation plan designed to mitigate risk to the extent possible as outlined in Table 1.

Table 1
Project Risks and Mitigation

Risk Identified	Mitigation
AMI technology is new.	All meter systems selected were lab tested prior to installation. In addition Hydro One did in field testing to verify the technology would work in our rural demographic. Vendors are required to support their technology through stringent warranties and on-site technical services throughout and following deployment.

Mass deployment of this order of magnitude has the potential to impact customer satisfaction through billing errors and communication and represents a significant cost.	Hydro One undertook a staged deployment. Stage 1 automated a pre-existing paper based process and included the deployment of hand held tools to virtually eliminate operator error. The tools were initially deployed for ongoing sustainment meter change work. Stage 2 extended the process to a community to begin to develop optimum crew and material logistics in a mass deployment scenario and test customer communications. Stage 2 operated in the communities of East Gwillumbury and Georgina. Billing errors as a result of this process were near non-existent and a customer survey concluded a high degree of satisfaction with our installation communications and processes. Stage 3 incorporated the processes optimized in stage 2 and was replicated in 2 additional operating areas. Stages 1-3 were successfully implemented in 2006. Mass deployment across additional zones will occur beginning in 2007.
Integration requirements are unknown.	Hydro One is operating on the principle that systems development will not occur in a material way until all requirements are understood. With the decision to have a third part data warehouse and Validate Estimate Edit (VEE) process (MDM/R) many of the integration requirements are now pending on vendor selection by the IESO and process definition that would occur after this selection. As a result Hydro One can only predict the timing for TOU billing recognizing that actual implementation is dependant on the IESO process.
Communications in rural and remote areas.	Hydro One has both a unique challenge and opportunity related to smart meter deployment. Our vast geography presents a challenge especially in areas were communications does not exist or is uneconomic. In this area Hydro One evaluated several communication technologies that would support meter requirements or provide the potential opportunity to support other business requirements. Our approach was to leverage current assets (e.g. optic cable fibre and towers) and leverage new assets to support additional business processes or to provide a higher level of customer services. The result of our assessment and testing indicated that there are emerging broadband wireless technologies that align

	well with Hydro Ones current assets and can be extended to support a high level of business requirements and customer service however this technology is also new. Hydro One has adopted the principle that it would begin with its urban areas first deploying existing communications technology and continue to examine future opportunities in this area. A communication architecture has been developed to permit this forward migration should a business case support its development.

A number of other risks have been identified along with the proposed means to mitigate them. These are listed in Table 2.

Table 2
Additional Risks and Mitigation

Risk	Mitigation
Competitive pricing / dated RFP	• Contracts include "most favoured nations" clause • Meter vendor was also selected through the government's procurement process with the CLD (Coalition of Large Distributors)
Changing specifications and timelines	• The IESO has been appointed as the overall project manager by the government and Hydro One has representatives on their working groups • We have selected a two-way open architecture that provides flexibility • Implementation plan is staged and tied to external timelines
Repairs to customer equipment for safety and damage on installation	• Identified to Ministry of Energy (MOE) and OEB as an item for cost recovery • Other LDCs also making repairs in the interim
Large number of smart meter customers opt for spot price	• Limitations on Hydro One's billing system would require standard system supply code change
Customer Satisfaction	• An initial customer survey on installation practices was conducted • Additional customer information on how to use smart meters is under development • Hydro One will coordinate with MOE on communications

7 Smart Meter Deployment

As of December 31, 2005 Hydro One served approximately 1.1 million customers and is forecast to grow to 1.3 million customers by the end of 2010. Table 3 provides a customer breakdown by rate class.

Table 3
Number of Customers by Rate Class
As of December 31 2005

Rate Class	Customers (000's)
Core	
Residential – High Density	300.1
Residential – Normal Density	270.8
Residential – Seasonal High Density	71.1
Residential – Seasonal Normal Density	83.0
Urban Residential	81.0
Farm – 1 Phase	89.4
Farm – 3 Phase	1.2
General Service – 1 Phase	63.8
General Service – 3 Phase	14.7
Urban General Service	6.4
Transmission	0.4
Core Total	981.9
Acquired	
MEU – Residential	141.2
MEU – General Service	21.9
Acquired Total	163.1
Grand Total	1,145.0

Hydro One has prepared a detail deployment plan divided between customers below 50kW (residential and small commercial) and customers above 50kW (commercial and industrial). This split recognizes the different skill sets required for these installations and also aligns with the decision to use meter reading routes to optimize travel during implementation.

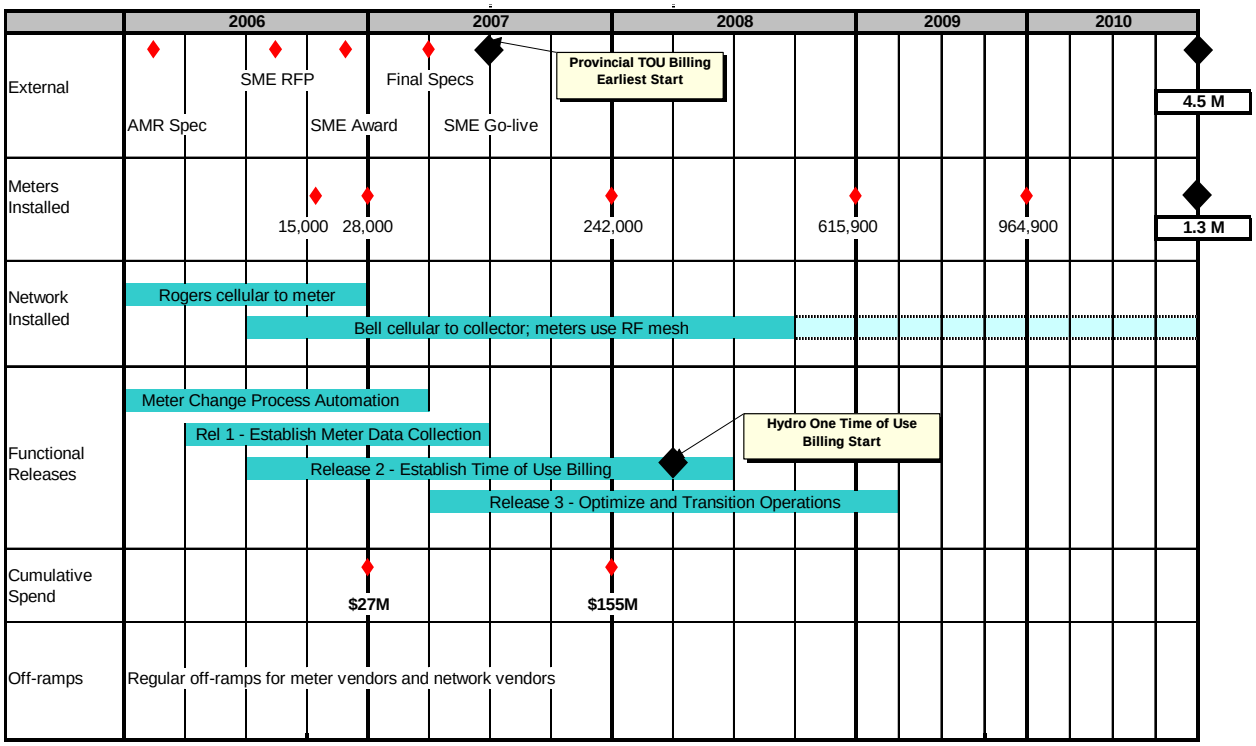
Further, Hydro One plans to implement smart meters for all new customer connections and for meter changes required as a result of ongoing Measurement Canada related programs (sample testing, re-verification and expired meter seals).

Table 4 outlines Hydro One's meter deployment plan in additional detail for the period 2006 through 2010.

Table 4
Smart Meter Deployment Forecast (000's)

Activity	2006	2007	2008	2009	2010
Below 50 kW					
Automated Process Testing	10.8				
Community Rollout	14.1				
Mass Deployment	3.1	156.1	295.6	276.0	279.3
New Connection/Upgrades		25.0	25.0	25.0	25.0
Measurement Canada Programs		9.7	12.4	9.5	6.2
Sweep Behind		21.2	37.0	34.5	34.5
Total Below 50 kW	28.0	212.0	370.0	345.0	345.0
Above 50 kW		2.0	3.9	4.0	
Total Meters Deployed	28.0	214.0	373.9	349.0	345.0
Cumulative Total	28.0	242.0	615.9	964.9	1,309.9

The following diagram outlines Hydro One work streams for the smart meter project.



8 Smart Meter Project Costs

Table 5 outlines Hydro One's forecast of the costs to implement the smart meter program company wide.

Table 5

Forecast of Expenditures ($ millions)

	2006	**2007**
Capital	21	119
OM&A	6	9
Total	27	128

Table 6 provides further detail of the smart meter expenditure components.

Table 6
Capital and OM&A Details

$ millions	**2006**	**2007**	**Total to 2007**
Capital			
Smart Meter Deployment	11	64	75
Communications	3	14	17
Billing System	2	17	19
Integration/Automation	5	12	17
Overheads	0	12	12
Total Capital	21	119	140
OM&A			
Development & Sustainment	6	9	15
Total	27	128	155

8.1 Customer Equipment

When Hydro One changes meters for a variety of reasons, it is inevitable that customer equipment repairs and upgrades are required. This can occur as a result of deteriorated meter bases and sockets, inaccessible meter locations and substandard services that no longer comply with approved policies to name a few.

Prior to smart meter implementation Hydro One's policy was to have customers make any repairs required to their equipment for safety or other reasons. Hydro One would typically provide electrical isolation until such repairs were made that would allow the safe restoration of power.

With smart meters and mass deployment Hydro One is now scheduling and deploying approved electrical contractors to make any required repairs to customer equipment and covering the cost of such repairs. Hydro One has taken this path as it is more practical to complete installations while crews are in the area, as it removes the barrier of customer negative reaction and increases safety as repairs are made and proper procedures are followed using approved contractors. A scan of the industry in and outside Ontario confirms that this is the common practice.

Based on installations Hydro One has completed to date the company has found that 10% of customer meter changes will require some form of additional attention. This might include a second trip or an appointment for the replacement of a customer's meter base. Hydro One also predicts there will be a material number of electrical service upgrades required for our larger customers. The average cost of this work has been estimated at $500 per occurrence.

8.2 Rural Service

Hydro One is unique in the province in its customer density make up. Hydro One customers average less that 10 customers per kilometre of line while our urban counterparts average 60-70 customers per kilometre of line. As well Hydro One operates in areas of heavy forestation and rugged terrain. The result is that both the cost of meter installations and telecommunications to the meter are higher. To compensate for the lower density on the telecommunications, Hydro One is deploying a wireless technology with radios ten times the transmit and receive power as their urban equivalents. Hydro One has also estimated that a larger number of signal repeaters and collectors will be required to ensure the Company is capable of meeting the AMI specifications captured in the Ontario regulations.

8.3 Condominiums

At this time regulations are in draft that address the requirement for smart meters in individual condominiums. The regulations as they currently sit place the responsibility for sub metering on the condominium corporation. As a result we have not included any

allowance for smart meters in condominiums or any other bulk metered customer facility (e.g. apartments, trailer parks, industrial complexes, etc.) in our smart meter forecast.

9 Revenue Requirement Analysis

Per the Board's request in their letter of October 13, 2006, Hydro One has calculated the impact the smart meter program will have on its revenue requirement for the period 2006 to 2007. Table 7 provides a summary of this analysis. Based upon Hydro One's forecast of the revenue requirement impact of the smart meter program, Hydro One will require an increase in the monthly smart meter rate rider which is currently set at $0.27 per metered customer ($0.30 per residential equivalent). The table shows a fiscal year requirement of $1.60 per metered customer per month in 2007. As such the $1.00 increment proposed by Board staff in section 4.3.1 of their July 25, 2006 Discussion Paper on the Cost of Capital and 2nd Generation Incentive Regulation, will not be sufficient to cover Hydro One's forecast costs for 2007.

Hydro One will be filing an application for rate relief to cover this smart meter deficit as part of its 2007 rates application.

Table 7
Smart Meter Revenue Requirement Analysis
$ millions

	2006	**2007**
Fixed Assets		
In Service	21	139
Accumulated Depreciation	1	7
Net Book Value	20	132
Revenue Requirement		
OM&A	6	9
Depreciation	1	6
Return on Rate Base	1	7
Revenue Requirement	8	22
Customers	1.2	1.2
Dollars/Customer/Month	0.50	1.60

10 Recovery of Stranded Meter Costs

Hydro One does not require any incremental relief to recover stranded capital costs of the "dumb" meters being replaced under this program. Hydro One's depreciation expense within its approved revenue requirement under EB-2005-0378, includes the impact of amortizing all of these older generation meters on straight-line basis over a period ending in 2010.

Consumers Council of Canada (CCC) INTERROGATORY #33 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

33 1/T1/S1p. 3

Please provide a detailed list of all of the reasons why HON is seeking to harmonize its rate classes across its service territory. Did HON consider other alternative approaches to setting rates across its service territory? If so, what were those approaches and why were they rejected?

Response

The reasons are described in Exhibit G1, Tab 2, Schedule 1, page 1, line 27 to page 2, line 21 and are presented again in Exhibit G1, Tab 2, Schedule 3, page 1, lines 7 to 9. In addition, Board Guidelines titled "Rate-Making Associated with Distributor Consolidation" issued July 23, 2007, say that at time of re-basing the issue of harmonization of rates should be addressed and it also states that the harmonization should be done within five years from the date of closing of the transaction. Hydro One is following the OEB Guidelines in proposing to harmonize the rates of the Acquired LDCs with the rates of the Legacy customers.

Hydro One followed OEB guidelines and responded to stakeholder feedback in developing its rates proposal, and as such did not consider alternative approaches to setting rates across its service territory.

Consumers Council of Canada (CCC) INTERROGATORY #34 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

34 1/T2/ S3/p. 2

Please provide the rationale for the definition of Urban Residential – 3000 or more customer customers with a line density of at least 60 customers per kilometer. Specifically, what is the rationale for 3000 or more customers? How was the cut-off point of 60 customers per kilometer determined? Did HON consider other criteria? If not, why not? If so, why were those criteria rejected?

Response

Hydro One is maintaining the currently approved Density threshold for its Urban Residential rate class of a 3,000 customer cluster and 60 customers per kilometre. Hydro One did not consider other criteria at this time since this Density threshold is representative of the population and density of other LDCs.

Consumers Council of Canada (CCC) INTERROGATORY #35 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

35 1/T2/S3/p. 3

Please provide a schedule setting out the current customer classes and rates for Caledon. Please indicate how those customers are being mapped into the new proposed customer classes.

Response

Exhibit G2, Tab 18, Schedule 2, page 1, includes a description of the current rates and customer classes in Caledon.

Caledon Residential CH-02 are being mapped to Urban Residential
Caledon Residential OH-01 are being mapped to R1
Caledon Residential class OH-06 is mapped to R2
Caledon residential class OH-07 is mapped to Seasonal

General Service classes in Caledon are being mapped to General Service energy billed and General Service demand billed.

Consumers Council of Canada (CCC) INTERROGATORY #36 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

36 1/T2/S3/pp. 4-5

Please explain the difference between the Urban General Service Energy Billed class and the General Service Energy Billed class. Is the only difference whether the customers meet the urban Density criteria?

Response

Yes, the only difference is whether the customers meet the Urban Density criteria.

Consumers Council of Canada (CCC) INTERROGATORY #37 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

37 1/T2/S3/p. 7

Please identify any impacts on HON's other customers resulting from the creation of the Distributed Generator rate class.

Response

The creation of the Distributed Generation class may result in some very minor impact to other classes in the form of reduced diversity in the other classes. Distributed Generators consume small amounts of power for station service and have diversity amongst themselves, that is, customers do not all require power at the same time, providing diversity benefits to the class. Having diversity means that less demand related costs would be allocated to the class when using coincident demand allocators in a cost allocation study. However, since the Distributed Generation class includes very few customers compared to the other classes, there would only be a very minor impact to the results for the other classes if Distributed Generation customers would be included with the other classes instead of being grouped in a class of their own.

Consumers Council of Canada (CCC) INTERROGATORY #38 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

38 1/T2/S5

For each of the Acquired LDCs please provide a schedule which sets out the existing residential rate classes, the current rates (fixed and variable) and the targeted rates.

Response

For Acquired Residential customers, the existing fixed and variable distribution rates are shown in Exhibit G2, Tab 2, Schedule 1, Table 1, pages 1 to 4. The targeted fixed and variable rates are shown in Exhibit G1, Tab 4, Schedule 2, Table 1, page 2. Acquired residential customers are being mapped to either UR or R1, with the exception of some Caledon Residential customers that are also being mapped to R2 and Seasonal classes.

Consumers Council of Canada (CCC) INTERROGATORY #39 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

39 1/T3/S1/p. 3

The evidence states that the revenue to cost ratio for the DG class is being moved from 1.63 to 1.0. Please provide a detailed explanation as to HON arrived at 1.0. Please explain how are the costs allocated to that class being reallocated to the other classes? Please provide a detailed calculation of the $.4 million revenue requirement allocated to the DG class.

Response

The proposed revenue to cost ratio of 1 for Distributed Generation is designed simply as a way to support Distributed Generation in Ontario. The difference between the current revenue to cost ratio and the proposed revenue to cost ratio is approximately $200,000. This amount is insignificant compared to the revenues expected to be collected from the other classes. No costs have been allocated away from the Distributed Generation class to the other classes. Exhibit G 2, Tab 1, Schedule 1, Attachment A, includes all the Cost Allocation details and how the $400,000 is being allocated to the DG class.

Consumers Council of Canada (CCC) INTERROGATORY #40 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

40 1/T3/S1/p. 3

If HON is proposing to move the DG revenue to cost ratio to 1.0, why would HON not be proposing to move the Street Lighting and Sentinel Light classes to 1.0 as well?

Response

Hydro one is not proposing a revenue to cost ratio of 1 for Street Lights and Sentinel Light customer classes in order to limit total bill impact. These two classes are already absorbing large bill impacts by being moved to a proposed revenue to cost ratio of 0.7.

Consumers Council of Canada (CCC) INTERROGATORY #41 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

41 1/T3/S1/p. 4

HON is proposing to adjust revenue to cost ratios resulting in a revenue requirement shortfall of $2.5 million. HON's proposal is to record this shortfall in a variance account to be recovered from customers at a future date. How will these costs be allocated and recovered in the future? Can HON point to any regulatory precedent which would support this proposed treatment?

Response

Hydro One would recover this amount from all customers in the future. The allocation method amongst customer classes could be done based on distribution revenues by class, number of customers by class, or energy consumed by class, for example. The regulatory precedent is explained in the interrogatory response in Exhibit H, Tab 1, Schedule 125.

Consumers Council of Canada (CCC) INTERROGATORY #42 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

42 1/T4/S2/p. 1

HON is proposing a $1 per account monthly charge for Street Lighting and Sentinel Lights. What is the basis for this charge? What are the total fixed costs associated with these customer classes?

Response

The basis for the $1 is to introduce a nominal fixed charge to these customer classes. These classes currently have no fixed charge included in the distribution charges. All other customer classes' rate design includes both a fixed and a volumetric charge.

The basis for the monthly service charge can be found in the Cost Allocation Model sheet O2 Fixed Charge|Floor|Ceiling. The model calculates a Fixed Charge range of $2.36 to $32.77 for the 2 lighting classes. Exhibit G2, Tab 1, Schedule 1, Attachment A, pages 37 to 40 show the details of the costs allocated to customer classes used to derive the range of fixed charges. Based on the Cost Allocation Methodology, the fixed charges ranges are shown in Exhibit G1, Tab 4, Schedule 2, page 2, Table 1.

The Cost Allocation Model output does not separate the costs into Fixed versus Variable components per rate class. However, the costs used to derive the Fixed Service Charge scenarios can be found in O2 Fixed Charge|Floor|Ceiling.

Consumers Council of Canada (CCC) INTERROGATORY #43 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

43 1/T4/S2/p. 1

HON has set out the fixed charge ranges as per the cost Allocation study. For each rate class please explain how the proposed fixed charges were determined.

Response

Exhibit G1, Tab 4, Schedule 1, page 1, line 9 to page 2, line 4, explains how the proposed fixed charges have been determined for each of the proposed customer classes. Exhibit G1, Tab 4, Schedule 2, Table 1, page 2, shows the ranges of fixed charges and the proposed target fixed charges.

Consumers Council of Canada (CCC) INTERROGATORY #44 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

44 1/T7/S1

HON is proposing to phase in rate adjustments to mitigate customer class impacts to less than 10% of the total bill per year. This is on an average basis. How does HON propose to treat customers that may experience bill impacts greater than 10%?

Response

Consistent with OEB guidelines in the 2006 EDR process, Hydro One has mitigated the impact to customer classes based on average class consumption. Customers consuming more or less than average will have different impacts, depending on their current and proposed rates. Hydro One does not propose any additional mitigation measures for customers that have consumption above or below the average for the class and that may see bill impacts greater than 10%.

Hydro One is already taking various measures to mitigate bill impacts to all customers. Exhibit G1, Tab 8, Schedule 1, page 1, line 16 to page 2, line 8, lists the proposed mitigation measures.

Please see the interrogatory response in Exhibit H, Tab 10, Schedule 45, for information on Hydro One's plan to communicate the proposed rate changes to its customers.

Consumers Council of Canada (CCC) INTERROGATORY #45 List 1

Interrogatory

Cost of Service

Cost Allocation and Rate Design

45 2/T2/S1

HON is proposing a rate harmonization plan for all of its acquired LDCs. For some customers the rate changes will be significant and therefore a mitigation plan is also being proposed. Please indicate how HON has, or intends to, inform all of its customers about the changes in their rates. Please provide copies of all correspondence/materials made available to HON customers related to the proposed rate changes.

Response

Given the potential impact of the harmonization proposal on customers of acquired utilities, Hydro One Networks ran a series of ads containing details of the harmonization proposal in 70 newspapers across the Province from January 22 to February 20, 2008. These ads, where possible, ran concurrently with the OEB Notice and were tailored to individual communities, containing specific rate impacts for those communities. A sample of the two ads (single community and multiple communities) are provided in Attachments 1 and 2 respectively.

In addition to the ads, phone calls were made to municipal officials to alert them to the application and the implications of harmonization for their communities.

Hydro One's website (www.HydroOneNetworks.com/2008RateApplication) contains all the filing detail as well as community specific impacts of harmonization and will continue to be updated as events warrant.

A special toll-free number was set up for calls from customers of acquired utilities with questions on our harmonization proposal. To date, this number has received less than 50 calls.

Hydro One will commence a further round of targeted, customer communication in the summer on our harmonization proposal. This campaign will include a combination of the following: bill messages, bill inserts and direct mail.

Attachment 1

Single Community Advertisement

Hydro One Networks is seeking OEB approval to harmonize its customers' rates

Starting in 2000, a number of people across the province became Hydro One Networks customers when we acquired their local utility. While the customers we acquired have seen changes to their delivery rates in recent years, many acquired customers continue to pay rates lower than other Hydro One customers receiving the same type of service.

Hydro One believes that all customers deserve fair, reasonable and affordable rates. In order for rates to be fair, they must be applied consistently across our customer base and reflect the true cost of delivering electricity to homes and businesses. For this reason, Hydro One is seeking to have all its customers pay the same rates for the same services. In some communities this could mean an increase to delivery rates. Under the proposed rate structure, all customers in the same rate class would be charged the same delivery rates, regardless of where they live.

The Ontario Energy Board (OEB) regulates the rates charged by all electric utilities in Ontario, including Hydro One, and must approve any changes to our delivery rates. On December 18, 2007, Hydro One applied to the OEB to harmonize or consolidate the rates in your community with other communities across Ontario served by Hydro One (OEB file number EB-2007-0681).

Based on our application, the delivery rate increase would be phased in over four years. This would limit the increase to less than10 per cent on the total bill in any one year for an average Hydro One customer. (The average Hydro One residential customer uses 1,000 kWh per month and the average general service energy-billed customer uses 2,000 kWh per month). The table below shows the proposed delivery rate increase for your community for 2008 and over four years for an average customer's electricity use.

Average Delivery Rate Increase on the Total Bill

	Residential customers using 1,000 kWh per month		**General Service energy-billed customers using 2,000 kWh per month**	
"Community Name" from Hydro One's Electricity Bill	**Average 2008 Increase on Total Bill**	**Average Increase on Total Bill at the end of 4 years**	**Average 2008 Increase on Total Bill**	**Average Increase on Total Bill at the end of 4 years**
Meaford	9.3%	18.0%	8.8%	21.0%

How do I know if this might affect me?
You can confirm if you have community-specific rates by checking on page two of your Hydro One bill. If your bill states either *"Your service type is Residential – Meaford"* or *"Your service type is General – Meaford"* you will be affected.

If approved by the OEB, the proposed rate increase will affect the Delivery line on your bill. For more information on our rate application, please go to www.HydroOneNetworks.com/2008RateApplication or call 1-866-543-8031. Our office hours are Monday to Friday, from 7:30 a.m. to 8 p.m.

Do I have a say?
Yes, you can participate in the OEB process. The OEB will undertake a public process, which includes a public hearing before rates are approved. Interested parties can intervene, observe or provide written comment. Public participation helps ensure the OEB makes an informed decision on our rates.

Information on how to participate may be obtained by visiting the OEB's website at www.oeb.gov.on.ca or by calling the OEB's Consumer Relations Centre at 1-877-632-2727.

hydro one

Bringing Power to the People of Ontario™

Attachment 1

Multiple Community Advertisement

Hydro One Networks is seeking OEB approval to harmonize its customers' rates

Starting in 2000, a number of people across the province became Hydro One Networks customers when we acquired their local utility. While the customers we acquired have seen changes to their delivery rates in recent years, many acquired customers continue to pay rates lower than other Hydro One customers receiving the same type of service.

Hydro One believes that all customers deserve fair, reasonable and affordable rates. In order for rates to be fair, they must be applied consistently across our customer base and reflect the true cost of delivering electricity to homes and businesses. For this reason, Hydro One is seeking to have all its customers pay the same rates for the same services. In some communities this could mean an increase to delivery rates. Under the proposed rate structure, all customers in the same rate class would be charged the same delivery rates, regardless of where they live.

The Ontario Energy Board (OEB) regulates the rates charged by all electric utilities in Ontario, including Hydro One, and must approve any changes to our delivery rates. On December 18, 2007, Hydro One applied to the OEB to harmonize or consolidate the rates in your community with other communities across Ontario served by Hydro One (OEB file number EB-2007-0681).

Based on our application, the delivery rate increase would be phased in over four years. This would limit the increase to less than10 per cent on the total bill in any one year for an average Hydro One customer. (The average Hydro One residential customer uses 1,000 kWh per month and the average general service energy-billed customer uses 2,000 kWh per month). The table below shows the proposed delivery rate increase by community for 2008 and over four years for an average customer's electricity use.

Average Delivery Rate Increase on the Total Bill

	Residential customers using 1,000 kWh per month		**General Service energy-billed customers using 2,000 kWh per month**	
"Community Name" from Hydro One's Electricity Bill	**Average 2008 Increase on Total Bill**	**Average Increase on Total Bill at the end of 4 years**	**Average 2008 Increase on Total Bill**	**Average Increase on Total Bill at the end of 4 years**
Chesley	9.0%	22.9%	8.8%	32.5%
Durham	8.9%	10.9%	8.9%	19.5%
Paisley	9.0%	22.9%	8.8%	32.5%
Tara	9.0%	22.9%	8.8%	32.5%

How do I know if this might affect me?
You can confirm if you have community-specific rates by checking on page two of your Hydro One bill. If one of the communities listed in the table above appears besides the words *"Your service type is Residential – Community Name"* or *"Your service type is General – Community Name"* you will be affected.

If approved by the OEB, the proposed rate increase will affect the Delivery line on your bill. For more information on our rate application, please go to www.HydroOneNetworks.com/2008RateApplication or call 1-866-543-8031. Our office hours are Monday to Friday, from 7:30 a.m. to 8 p.m.

Do I have a say?
Yes, you can participate in the OEB process. The OEB will undertake a public process, which includes a public hearing before rates are approved. Interested parties can intervene, observe or provide written comment. Public participation helps ensure the OEB makes an informed decision on our rates.

Information on how to participate may be obtained by visiting the OEB's website at www.oeb.gov.on.ca or by calling the OEB's Consumer Relations Centre at 1-877-632-2727.

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Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #1
List 1

Interrogatory

Issue Number: 1.4
Issue: Are Hydro One's Economic and Business Planning Assumptions for 2008 appropriate?

Ref: A/Tab 3/Sch 1/Page 2/Table 1

a. Does Hydro One measure customer satisfaction for its distribution customers by geographic zone or area? If so, please provide a table indicating how customer satisfaction results vary across the service territory.
b. If there is more than one, please identify the major customer segments Hydro One includes in its customer service goal, and current measured levels of customer satisfaction for each.

Response

a) The Hydro One Overall customer satisfaction results can be segmented by geographic zone. The 2007 results are included in the table below:

	Geographic Area				
2007 Overall Satisfaction	**North**	**West Central**	**East Central**	**East**	**West**
Residential/Small Business	80%	81%	83%	84%	82%

b) Please see the IR response in Exhibit H, Tab 7, Schedule 19.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #2
List 1

Interrogatory

Issue Number: 1.4
Issue: Are Hydro One's Economic and Business Planning Assumptions for 2008 appropriate?

Ref: A 1 /Tab 3/Sch 1/Page 2/Table 1

a. Please provide the date and rationale supporting establishment of the 2010 strategic goal of first quartile (like for like) reliability.
b. Also, please provide any source information the company relied on with respect to customer expectations, customers' willingness to pay and expected impacts on rate base and operations costs that were considered in the establishment of the reliability goal.

Response

a. Since 2002, Hydro One has clearly and consistently articulated our mission statement and strategic goals and targets through our business values, our Transmission and Distribution rate filings, and other public pronouncements such as Annual Reports, Annual Information Forms, and speeches by Hydro One senior management.

   The strategic goal of first quartile reliability in a like for like comparison was first drafted in 2005 as an element of a five year objectives initiative. Our current Mission Statement now reads:

   "Our mission is to be an efficient transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value."

   Hydro One Distribution is driven by the Corporate Mission and business values and together, they provide the basis to deliver on targeted performance objectives. Our current revenue requirement is therefore based on achieving these objectives in a staged manner.

b. Hydro One's key stakeholders have been consulted regarding our level of performance, which we have used to translate into our Mission Statement and business values. Our Mission Statement was jointly developed using input from various stakeholders including, but not limited to:

- Our shareholder
- Customer Advisory Boards (CABs)
- Stakeholder meetings and consultations
- Discussions with the shareholder
- Direct customer contact
- Customer surveys focusing on the importance of such attributes as reliability and the importance of price.

The costs associated with achieving our corporate objectives are inherently contained within the Revenue Requirements of both our Distribution and Transmission rate filings. There is no analysis available which correlates dollars spent with specific steps or stages in achieving Hydro One's strategic targets and goals.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #3
List 1

Interrogatory

Issue Number: 1.4
Issue: Are Hydro One's Economic and Business Planning Assumptions for 2008 appropriate?

Ref: A/Tab 14/ Sch 2/Page 3/Table 3

a. This table appears incorrect, in that it defines the exchange rate as CDN$/US$ and the ratios provided do not seem to match the definition. Moreover, the projections for 2007 and 2008 seem out of line with experience. Please either explain or correct.

Response

a. The CDN$/US$ ratio indicates the number of Canadian dollars per US dollar (i.e., the number of Canadian dollars required to purchase a single US dollar) which is the conventional market quotation. The rates for 2004, 2005 and 2006 are the annual noon exchange rate averages for each year from the Bank of Canada's website. The rates shown for 2007 and 2008 were forecast in 2006 and hence will differ from the actual rates.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #4
List 1

Interrogatory

Issue Number: 1.4
Issue: Are Hydro One's Economic and Business Planning Assumptions for 2008 appropriate?

Ref: A/Tab 14/Sch 2/Page 7/ Line 10

a. This section refers the reader to Appendix A of Exhibit A, Tab 14, Schedule 1 for a table of labour rate escalation factors. However, the appendix seems to be missing. Please provide the appendix mentioned.

Response

Appendix A of Exhibit A, Tab 14, Schedule 1 is provided in the pre-filed evidence dated August 15, 2007. The cited reference can be found in Appendix A, Section 3.0 Labour Escalation on, page 2 of 3, line 8.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #5
List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref: A/Tab 14/Sch 3/Page 2/Table 1

a. Please provide the source energy or demand data (forecast, actual and weather corrected) from which this table was calculated, including the corresponding 2007 data if available.

Response

a. The requested information is provided below:

Forecast of Retail Purchases (GWh)

For Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1997	19,000										
1998	18,800	18,800									
1999	18,900	17,917	18,389								
2000		17,800	18,299	18,058							
2001			18,342	18,170	17,849						
2002				18,329	17,907	22,841					
2003					18,038	23,118	22,391				
2004						23,424	22,624	22,970			
2005							22,807	23,120	23,035		
2006								23,290	23,144	23,102	
2007									23,385	23,250	23,256

Actual Retail Purchases (GWh)

For Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1997	18,788										
1998	18,325	18,325									
1999	18,146	18,146	18,146								
2000		17,779	17,779	17,587							
2001			17,820	17,626	17,626						
2002				18,395	18,395	22,672					
2003					18,593	22,711	22,711				
2004						22,768	22,768	22,768			
2005							23,190	23,190	23,190		
2006								22,679	22,679	22,679	
2007									23,220	23,220	23,220

Weather Corrected Retail Purchases (GW.h)

For Year	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1997	18,977										
1998	19,191	19,191									
1999	18,547	18,547	18,547								
2000		18,167	18,167	17,975							
2001			18,370	18,176	18,176						
2002				18,190	18,190	22,399					
2003					18,489	22,577	22,577				
2004						22,937	22,937	22,937			
2005							22,977	22,977	22,977		
2006								23,115	23,115	23,115	
2007									23,278	23,278	23,278

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #6
List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref: A/Tab 14/Sch 3/Page 8/Line 16

The 350MW reduction ordered by the Board in EB-2006-0501 was for the forecast of average monthly peak Ontario demand.

a. Please provide the calculation details regarding how this reduction was translated from Ontario demand into Hydro One Distribution energy sales.

Response

a. To follow the Board's directive in EB-2006-0501, Hydro One Distribution applied an adjustment factor of 1000/1350 (1350 MW-350 MW = 1000 MW) to the CDM impact for 2007. The following table shows the CDM impact in 2007 before and after the adjustment.

CDM Impact on Hydro One Distribution Load (GWh)

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
Before Adjustment			
2007	420	327	747
After Adjustment			
2007	311	242	554

Adjustment factor is 1000/1350

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #7
List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref: A/Tab 14/Sch 3/Page 8/Line 17

In the IPSP (Ex D, Tab 4, Sch 1, Attachment 2, page 1, Table 1) the OPA identifies 600MW cumulative of naturally occurring conservation by the end of 2007.

a. Please provide the calculation details as to how this 1 was accounted for in the Hydro One distribution load forecast.
b. Please provide the specific data references in the IPSP that support the statement "The 2008 CDM impact is consistent with the OPA's IPSP filed with the Board on August 29, 2007."

Response

a. Hydro One Distribution's load forecast is already net of natural conservation. Therefore, there is no need to make further adjustment to account for natural conservation.

b. Hydro One Distribution used the 2008 provincial CDM impacts provided by the OPA to calculate its share of the CDM impacts. The provincial CDM peak and energy savings for 2008 used in the IPSP are 251 MW and 0.8 TWh respectively (EB-2007-0707 Exhibit D, Tab 4, Schedule 1, Attachment 4, page 2, Table 1 and Table 2).

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #8
List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref: A/Tab 14/Sch 3/Page 10/Lines 11 – 14

This projection indicates that customer growth in 2008 is expected to be 9,400, down from the 2002-2006 average of 12,000 annually (exclusive of Terrace Bay addition). This seems to represent a decline of about 22%. However, in Exhibit D1, Tab 3, Sch 4, page 14, Lines 12-28, new connections are estimated at the historical average of 17,600 annually.

a. It would appear that both these assertions cannot be correct. Please provide a discussion, explanation or correction.

Response

a. The table below provides the details for Ontario housing starts, new connections, and customer additions:

Year	Ontario Housing Starts	New Connects	Customer Additions
2003	85900	17,994	10,814
2004	84500	18,177	14,306
2005	77800	18,320	12,403
2006	74400	18,231	10,575
2007	67000	17,412	10,963
2008	68000	17,583	9,413

Note: 2007 and 2008 are forecast

Customer additions are new (net) customer additions that are closely related to the housing activities in the province. In Hydro One Distribution, new connections include new customer additions, service cancellations, street lights, central metering connections and multiple connections within one account. The following example will help reconcile the new connections with new customer additions in 2008.

New Connections:	17,600
Less service cancellation	5,500
Less central metering	1,000
Less multiple service points	1,000
Less streetlight	700
Equals New Customer Additions	9,400

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #9
List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref: A/Tab 14/Sch 3/Page 20/Table 4

a. Please provide actual (weather normal) as opposed to forecast load data for 2006 and 2007.

Response

a. The requested information is provided below:

Weather Normal Actual Hydro One Distribution Load (GWh)

Year	Retail	Embedded	Total
2006	22,921	17,688	40,609
2007	22,966	17,562	40,529

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #10
List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref: A/Tab 14/Sch 3/Page 20/Table 4
A/Tab 10/Sch 1/Inside cover

a. Please provide a reconciliation or explanation for the difference between the 2006 load forecast(s) in this table and the figure of 29.0 TWh provided in the 2006 annual report (inside cover, Ex A/Tab 10/Sch 1).

Response

a. The figure of 29.0 TWh provided in the 2006 annual report (inside cover, Exhibit A/Tab 10/Schedule 1) measures Hydro One Retail customers plus embedded non-market participant load (25.1 TWh) plus Hydro One Brampton load.(3.9 TWh). In contrast, Hydro One Distribution load in Exhibit A, Tab 14, Schedule 3, page 20, Table 4 measures Hydro One Retail customers (22.7 TWh) and all embedded customers, including market participants and non-market participants (17.6 TWh) summing up to (40.3 TWh).

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #11
List 1

Interrogatory

Reference: Ex. A, Tab 15, Sch. 1, p. 7, Table 1
Issue: Is service quality on the OEB specified performance indicators acceptable?

a) Please provide the System Average Interruptions Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI) targets the company believes it will need by 2010 to meet if it is to achieve its strategic goal of being a first quartile (like for like) performer in these categories.

Response

The benchmark for achieving "top quartile" performance changes over time based on the latest performance of comparable utilities rather than historical or projected results. The benchmark could also change as the group of comparable utilities is refined to better reflect like-for-like comparisons. Improvement over historical results may appear to be significant, however if the comparable utilities make larger improvements the benchmarking ranking may deteriorate. Similarly, it is not possible to project future changes in performance of other comparable utilities. Therefore, as stated in the filing, the strategic goal is broadly stated as becoming a leading ("top quartile") utility in reliability, based upon like for like comparisons.

Assuming the historical performance levels stay the same for the current panel of existing comparable Canadian utilities (not all of which provide true like-for-like comparisons without some additional normalizing of performance results) Hydro One's estimate of what it means in 2008 to achieve "top quartile" performance levels would be a SAIDI of 3.9 hours of interruption per customer, a SAIFI of 2.1 interruptions per customer, and a corresponding CAIDI of 1.9 hours per interrupted customer. This compares to 2008 performance targets of 8.0 hours for SAIDI and 2.9 interruptions for SAIFI.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #12
List 1

Interrogatory

Issue Number: 1.6

Issue: Is service quality on the OEB specified performance indicators acceptable?

Ref: A/Tab 15/Sch 1/Page 7/Table 1

a. Does Hydro One break out reliability measures by territory, zone or area? If so, please provide a table indicating the 2006 and/or 2007 results by geography?

Response

Hydro One does not break out reliability measures by territory, zone or area as part of its annual reporting to the Ontario Energy Board. However, the table below provides an indicator of distribution reliability by geography.

		Excluding Force Majeure		Including Force Majeure	
Geography	YEAR	Cust Hr/Route Km	Cust Int/Route Km	Cust Hr/Route Km	Cust Int/Route Km
CENTRAL	2006	155	50	915	101
NORTH	2006	103	37	159	43
SOUTH	2006	56	26	199	47
CENTRAL	2007	164	57	225	68
NORTH	2007	105	45	114	47
SOUTH	2007	77	34	104	39

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #13
List 1

Interrogatory

Issue Number: 1.7
Issue: Are the proposed distribution loss factors appropriate?

Ref: A/Tab 15/Sch 3/Page 6/Line 1

Since subtransmission class customers use only a portion of the Hydro One distribution assets, it is difficult to understand why they should be allocated the same proportion of non-technical losses as other customers.

a. Please identify whether Hydro One has experienced any unrecovered theft of power from its subtransmission system in the past five years.
b. Please identify the metering accuracy requirements for Large User meters, and the range of meter inaccuracies Hydro One has found through its meter verification program.
c. Please provide a description of the types and numbers of un-metered loads Hydro One has that are serviced by its subtransmission system.

Response

a. Hydro One has not identified theft of power from its subtransmission system in the past five years. This does not mean that it does not happen.

b. Hydro One retail metering accuracy requirements conform to Measurement Canada's requirement for electricity revenue metering. Hydro One has not tracked the range of meter inaccuracies through its meter verification program except for sampled meters related to our energy-only meter sample reverification program, but will resolve any metering accuracy issues as required. Hydro One has encountered a very small number of instances, averaging one or two per year, where meter data inaccuracies have been encountered.

c. All loads supplied by Hydro One are serviced through its sub-transmission system.

The types and numbers of un-metered loads served by Hydro One, through its sub-transmission system, are as follows:
Street Lights Accounts = about 5,000
Sentinel Light Connections = about 30,000
Un-metered Scattered Load Connections = about 5,000

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #14
List 1

Interrogatory

Issue Number: 1.7
Issue: Are the proposed distribution loss factors appropriate?

Ref: A/1 Tab 15/Sch 3/Attachment A, p11.

The discussion in this section seems to suggest that all customer classes have identical portions of non-technical losses associated with their use of the system (1.2%). If the total non-technical losses represent 1.2% of total energy billed, then it seems logical to assume that, as with technical losses, these would accumulate as power flows from subtransmission to primary and on to the secondary system, with the largest portions likely occurring where such factors as theft of power are most likely to occur. In turn, this would suggest that the subtransmission system on its own must have a non10 technical loss factor of less than 1.2%. The explanation given in the Kinectrics report at the bottom of page 11 seems overly cursory. Using Kinectrics' figures in Table 6, it appears that non-technical losses account for over 30% of all subtransmission losses (1.2/3.8), while accounting for less than 13% (1.2/9.4) of the losses attributed to customers taking power at secondary voltage.

a. Please provide the calculation detail Kinectrics used in arriving at the 1.2% factor for all classes.

Response

Kinectrics did not evaluate non-technical losses on a class by class basis. The analysis was based on establishing non-technical losses for all customers.

Kinectrics' analysis determined a value of 1.2% non-technical losses based on a review of experience in other jurisdictions.

It is Kinectrics' view that the assertion that non-technical losses "would accumulate as power flows from subtransmission to primary and on to the secondary system" is incorrect. Kinectrics is not aware of any references that support the contention that non-technical losses are lower at higher voltages. Non-technical losses include both theft and fraud, as well as metering inaccuracies. Although theft may be easier at lower voltages, the larger customers at higher voltages have more to gain from theft and fraud and metering inaccuracies result in much larger impacts. Therefore non-technical losses are equally possible at any level.

Hydro One does not propose to change the loss factors currently approved by the OEB. The current total loss factors include an estimate for non-technical losses. The estimate is 10% of the technical losses as shown in the footnote to Table 2, on page 2 of Exhibit A, Tab 15, Schedule 3, Attachment A. Hydro One's application proposes to use this OEB approved estimate for non-technical losses and is not seeking approval to use the 1.2% estimate in the Kinectrics study.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #15
List 1

Interrogatory

Issue Number: 3.1
Issue: Are the overall levels of the 2008 Operation, Maintenance and Administration budgets appropriate?

Ref: C1/Tab 2/Sch 4/Table 1

a. Please explain in more detail the reasons for the cost increase for Operations from $11.1M in 2007 to $13.4M in 2008.

Response

Refer to Interrogatory response in Exhibit H, Tab 13, Schedule 13.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #16
List 1

Interrogatory

Issue Number: 3.1
Issue: Are the overall levels of the 2008 Operation, Maintenance and Administration budgets appropriate?

Ref: C1/Tab 2/Sch 5/Page 9/Line 15

a. Please provide the number of manual meter readings performed each year from 2004-2007, as well as the expected level for 2008.

Response

The table below provides the number of manual meter readings from 2004-2007 and the 2008 plan amount.

Description	Historic			Bridge	
	2004	2005	2006	2007	2008
Total no. of manual meter reads	4,321,354	4,418,151	4,457,764	4,510,251	4,110,000

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #17
List 1

Interrogatory

Issue Number: 3.1
Issue: Are the overall levels of the 2008 Operation, Maintenance and Administration budgets appropriate?

Ref: C1/Tab 2/Sch 2

a. Are the sustaining OM&A programs for lines, stations and vegetation management designed to maintain current service reliability, or to improve service reliability on a schedule to achieve the corporate strategic goal for reliability by 2010?

Response

OM&A programs are designed to address a number of business values, including reliability, as discussed in Exhibit A, Tab 14, Schedule 5, page 3. Not all programs impact reliability to the same extent and as a result, Hydro One has different reliability objectives for each program.

Analysis shown in Exhibit A, Tab 3, Schedule 1, pages 18 and 19 indicates that by the far the greatest contributor to unreliability is "Tree Contacts". With this in mind, Hydro One has designed the Vegetation Management Program in a manner that improves reliability consistent with the direction set by the corporate 2010 strategic goals.

Analysis shown in Exhibit A, Tab 3, Schedule 1, pages 18 and 19 also shows that the next greatest contributor to unreliability is "Defective Equipment". This category is very broad and captures failures of all equipment types. Due to the wide array of equipment on the system and the relative impact of equipment compared to vegetation, it is very difficult to greatly influence the overall reliability of the system through targeted Lines or Stations maintenance programs. As a result, Lines and Stations programs are planned to meet some reliability improvement objectives, but are generally influenced more by the need to restore asset condition, maintain a high level of safety for the public and workers, as well as maintaining equipment performance.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #18
List 1

Interrogatory

Issue Number: 3.2
Issue: Is the 2008 vegetation management budget appropriate?

Ref: C1/Tab 2/Sch 2/Page 30/Table 9

a. Please provide accomplishment data (km) for line clearing and brushing for each year from 2004-2007.

Response

Please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 63.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #19
List 1

Interrogatory

Issue Number: 3.3
Issue: Is the proposed level of 2008 Shared Services and Other O&M spending appropriate?

Ref: C1/Tab2/Sch6/Pages 3&4, Tables 1&2

Table 2 indicates that the corporate total cost of asset management in 2008 will be $118.9M, of which $46.3M will be allocated to the distribution function. From Table 1, this represents an increase of over 20% from the 2007 level of $38.1M. The Board decision in EB-2006-0501 approved the 2008 transmission work program based on a proposed corporate total budget for asset management of $96.4M.

a. Please explain in detail the reasons for a more than 20% increase in asset management cost for distribution.
b. Please explain the difference between the approved total shared services budget for asset management budget of $96.4M from EB-2006-0501 and the figure of $118.9M provided in this application.

Response

a. Please see Interrogatory response Exhibit H, Tab 1, Schedule 85.

b. The 2008 total cost for Asset Management activities of $118.9M provided in this filing is based on more current information, as compared to the cost of the 2008 total Asset Management activities of $96.4M submitted in EB-2006-0501

The information in EB-2006-0501 was developed in the spring of 2006 while the information for this filing was developed in the spring of 2007. During that period the understanding of the complexity of size of the activities that Asset Management undertakes to support the business became greater and several new activities grew in scope (e.g. Distribution Generation Connections).

A summary of the cost comparison between this application and EB-2006-0501 is provided in the following table:

Description	2008 Costs		
	Distribution Application EB-2007-0681 C1/2/6, pg 4	Transmission Application EB-2006-0501 C1/2/5, pg 4	Difference
SBD	9.6	8.3	1.3
System Investment	32.2	21.9	10.3
Business Integration	20.3	16.1	4.2
Facility & Real Estate	44.0	40.5	3.5
Business Transformation	3.2	2.5	0.7
Customer & Business Relations	4.9	4.1	0.8
Work Program Operations	4.7	3.0	1.7
Asset Management	118.9	96.4	22.5

The increase in Asset Management is primarily due to:

- Approximately $17.8M increase across the functions is to support increasing OM&A and Capex work program for scoping and planning, Cornerstone project support, increasing regulatory and rate filing work load, compliance activities including bill 198 and IESO programs and succession and demographics planning.

- Approximately $1.3M increase in consultants/contract staff in System Investment to support increased work related to generation connections and Cornerstone project.

- Approximately $3.5M increase in Facility & Real Estate costs due to new employee workspace accommodation requirements and staffing related costs (work-load driven).

Further related information can be found in interrogatory response Exhibit H, Tab 1, Schedule 85.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #20
List 1

Interrogatory

Issue Number: 3.3
Issue: Is the proposed level of 2008 Shared Services and Other O&M spending appropriate?

Ref: C1/Tab 2/Sch 6/Attachment A/Section 4.5/Lines 26-28

a. Please identify the rate of efficiency and productivity improvement assumed or specified in the Inergi contract for 2008-2010.

Response

a. The pricing for the Inergi outsourcing arrangements was negotiated with a fixed decline of 30% in real terms over the 10 year term of the agreement for the same volume and quality of services experienced during the 12 months prior to the commencement of the outsourcing arrangements. The actual decline in base service fees (before cost-of-living adjustments and contract changes) for the period 2008-2010 is as follows:

2008/2007	3.2% decline
2009/2008	3.6% decline
2010/2009	3.3% decline

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #21
List 1

Interrogatory

Issue Number: 3.3
Issue: Is the proposed level of 2008 Shared Services and Other O&M spending appropriate?
Ref: C1/Tab 4/Sch 2/Page 3/Section 2.0

a. Please identify whether Hydro One regards the INERGI outsource contract as a cost efficiency initiative.
b. If so, please provide a short analysis if its success as a cost efficiency initiative.

Response

(a) The Inergi outsource contract is identified as a cost efficiency initiative for Hydro One Networks.

(b) Hydro One has successfully achieve expected annual savings to date. The pricing for the Inergi outsourcing arrangements was negotiated with a fixed decline of 30% in real terms over the 10 year term of the agreement for the same volume and quality of services experienced during the 12 months prior to the commencement of the outsourcing arrangements. These arrangements are compared with internal projections that Hydro One could not have achieved the contracted price decline if delivered internally. The annual price decline is partially offset by adjustments for the following elements during the term of the agreement:
   a. Adjustments for cost-of-living (COLA) based on specified Ontario labour related indices published by Statistics Canada.
   b. Adjustments for changes in volume, scope or quality of services demanded by Hydro One Networks.

   For further information regarding % annual savings for 2008-2010, see interrogatory Exhibit H, Tab 11, Schedule 20.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #22
List 1

Interrogatory

Issue Number: 4.2
Issue: Are the amounts proposed for 2008 Capital Expenditures appropriate?

Ref: D1/Tab 2/Sch1/Page 7

a. Please identify any assets for which the basis for establishing the health index has changed significantly since Hydro One's filing in EB-2005-0378.
b. For any assets where the basis for establishing the health index has changed, please provide an estimate of the effect this has had on placing these assets into the condition categories listed in Table 4.1.

Response

a. and b. The table below summarizes the changes that were made to the basis for establishing the health index for assets listed in Table 4.1 of Exhibit D1, Tab 2, Schedule 1. Comments on changes and impacts are relative to results in Hydro One's last filing (EB-2005-0378).

Asset	Significant Change	Impact
Station Transformers	ACA results were based on DGA results. In EB-2005-0378, results were based on a combination of tests and condition ratings, the most heavily weighted of which were DGA Tests, Winding Doble Tests, and Furan Tests. The changes to the ACA calculation were made to focus on highly weighted factors and the emphasis on DGA was driven by the following: • Hydro One focused on DGA as it is considered to be one of the most telling markers of transformer condition and tests are conducted annually. • Winding Doble Tests are not conducted frequently for distribution assets. • The industry has recently raised concerns with Furan Test results and their validity as condition markers.	No Significant Impact

Land Assessment & Remediation	The 2006 assessment was based MOE guidelines for agriculture/residential land-use. The condition rating has been adjusted to reflect land use for industrial properties and only those sites where there is a risk of contaminants migrating off site, or where there is a safety issue associated with the contamination have been classified as "Very Poor". This assessment aligns with work planning practices.	Approximately 40% moved from "Very Poor" to "Good" or "Very Good"
Wood Poles	No Significant Change	No Significant Impact
Distribution Line Sections	No Significant Change	No Significant Impact
Rights of Way	ACA results were based on condition criteria (i.e. tree clearance, overhang, danger trees, and tree density). In EB-2005-0378, results were based on condition criteria and the "Forestry Outage Index (FOI)" that incorporated reliability performance. Hydro One excluded the FOI to focus on "condition" since reliability impacts are considered separately for both program funding and specific feeder scheduling. The aspect of reliability representing a marker for condition was removed from the ACA. Reliability receives a separate focus to manage and schedule work.	No Significant Impact on results.

1

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #23
List 1

Interrogatory

Issue Number: 4.2
Issue: Are the amounts proposed for 2008 Capital Expenditures appropriate?

Ref: D1/Tab 2/Sch1/Page 10/Table 4.2

a. Please confirm that "Transformer Failure" as defined in this table, means a failure that required the transformer to be removed from its location for either major repair or replacement. If this is not the definition Hydro One is using, please provide the definition that is being used.

Response

a) The transformer failures shown in Table 4.2 are the sum of Class 1 and Class 2 Failures. The definitions for Class 1 and Class 2 are as follows:

1. Class 1 Failures: Refers to major failures which require off-site assessment and repair. Typically the failure will involve the core, windings, and/or tank.

2. Class 2 Failures: Refers to failures of a less severe nature where damage is such that repairs can be executed on site. Typical examples are tapchanger contact/reversing switches, bushings, minor oil leaks, etc.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #24
List 1

Interrogatory

Issue Number: 4.2
Issue: Are the amounts proposed for 2008 Capital Expenditures appropriate?

Ref: D1/Tab 2/Sch 1/Page 14/Fig. 3

a. Please identify what, if any, maintenance, life extension, or reinforcement ties Hydro One performs on its wood pole population.
b. If Hydro One does not perform life extension activities for poles, please provide the analysis and assumptions supporting this decision.

Response

a. Hydro One performs life extension on poles that are tested (i.e. drilled to measure the remaining sound shell thickness) by applying wood preservatives to the interior of the pole at the drill locations. In-situ applications of wood pole preservatives to the exterior of a pole are not currently in use, nor is the reinforcement of poles at the ground line.

b. Hydro One has assessed pole reinforcement (e.g. steel stubbing) methods. Although the concept of reinforcement is promising, there are still challenges related to climbability of reinforced poles, fall protection, total cost, and expected life gain. Considering these factors, pole reinforcement has not been adopted as a standard practice.

Hydro One has investigated the use of preservative wraps on the exterior of poles, however these are not being applied at this time. To fully capture the benefits of preservative wrap, a targeted approach is required by applying the wrap at cost-effective pole locations as opposed to usage on a wide scale basis. Hydro One has elected to defer usage of preservative wraps until it can obtain the detail information on its wood pole plant through the wood pole assessment and data collection program. Once the detailed plant information has been obtained, Hydro One will determine locations where added ground line preservative is cost effective solution for wood pole life extension.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #25
List 1

Interrogatory

Issue Number: 4.2
Issue: Are the amounts proposed for 2008 Capital Expenditures appropriate?

Ref: D1/Tab3/Sch 2/Page 13/Table 1

a. Please provide the number of poles replaced or expected to be replaced under the trouble call and storm damage capital category in the historic, bridge and test years.

Response

The number of poles replaced under the trouble call program is provided in the following table. An accurate number of the poles replaced under the capital storm damage program is not available.

2004	2005	2006	2007	2008 Projection
890	1,428	1,393	1,321	1,300

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #26
List 1

Interrogatory

Issue Number: 4.2
Issue: Are the amounts proposed for 2008 Capital Expenditures appropriate?

Ref: D1/Tab 3/Sch2/Page 27, line 18 to Page 28, line 8

a. Please identify separately the costs for the Cost Information System (CIS) upgrade needed to meet the government directive on smart meters from the incremental project cost to leverage the Automated Information System (AMI) system for service improvements.
b. Please provide the business case for the enhancements to leverage the AMI system.

Response

a) The breakout of capital costs for 2008 is provided in the IR response in Exhibit H, Tab 10, Schedule 28. The forecast costs to upgrade the CIS, and related open market systems, to provide for TOU billing are approximately $18.2M This includes the costs of adding TOU tariff capability, accepting automated time differentiated consumption data, automated meter related service orders and to synchronize with AMI and MDMR systems. This does not include integration costs for other systems or automation to manage the end to end meter to bank processes and transactions efficiently (this has been identified as "Integration and Transaction Management").

b) Business benefits related specifically to the smart meter initiative are outlined in Exhibit C1 Schedule 2 Tab 2 and discussed in the IR response in Exhibit H, Tab 1, Schedule 127, part i).

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #27
List 1

Interrogatory

Issue Number: 4.4
Issue: Are the 2008 amounts proposed for Development capital appropriate?

Ref: D1/Tab 3/Sch 3/Page 3/Table 2

a. Please provide a table similar to Table 2, with accomplishment units for the historic years and bridge years and projected accomplishment units for the test year. This is not required for meter purchases.
b. Please explain in some detail the reasons for the expected increase in cost for service upgrades and whether this estimate includes consideration of the impact of Conservation Demand Management (CDM) programs in slowing the increase in energy consumption.

Response

a)

New Connections & Service Upgrade Volumes

	Actual	**Actual**	**Actual**	**Actual**	**Forecast**
	2004	**2005**	**2006**	**2007**	**2008**
New Connections	17,959	18,320	17,110	18,023	17,600
Service Upgrades	5,906	5,759	5,524	4,892	5,500*

* This is a correction to the figure of 6,500 provided in Exhibit D1, Tab 3, Schedule 3, page 5.

b) Projected cost increases in service upgrades are mainly due to escalation in material and equipment costs, however year over year costs also fluctuate with the type of upgrades implemented.

The volumes are not expected to be significantly impacted by CDM activities. Although energy use may be lower due to CDM, service upgrades are generally associated with new construction/renovation activities at existing customer premises and most customers require the service entrance equipment to be upgraded to meet code requirements when such activities take place.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #28
List 1

Interrogatory

Issue Number: 4.6
Issue: Is the proposed level of 2008 Shared Services and Other Capital expenditures appropriate?

Ref: D1/Tab 3/Sch 5/Page 1/Table 1
D2/Tab 2/Sch 3/Ref #IT1

For the Cornerstone Phase 1 Project. Table 1 shows costs for 2007 and 2008 as $60.4M and $63.0M respectively. However, the Investment Justification indicates net investment for 2007 and 2008 of $83.7 and $63.4M respectively.

a. Please provide an explanation or confirm that the figures on Table 6 are the most up to date.

Response

a. In 2008, the $56.3M in the Investment Justification relates to Phase I Capital and OM&A. The $63.0M in Table 6 for 2008 is only for Capital, and relates to Phase I and subsequent phases. The 2007 numbers in the question differ because of the inclusion of OM&A in Investment Justification IT1.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #29
List 1

Interrogatory

Issue Number: 4.6
Issue: Is the proposed level of 2008 Shared Services and Other Capital expenditures appropriate?

Ref: D1/Tab3/Sch 5/Page 32/Lines 21-24

The explanation given for the increase in Transport & Work Equipment (TW&E) capital investment is that the increase is directly related to the increase in work programs.

a. Please identify the specific work program increases that are driving the increase in TW&E acquisitions.

Response

Per Exhibit D1, Tab 3, Schedule 5, page 35, lines 7 and 8, the additional capital identified in 2008 is a direct reflection of the increase in the work program and additional staffing identified by all the Lines of Business within Hydro One.

The following are the primary items contributing to the TW&E capital increases from 2007 to 2008:

- additional staffing requirements, primarily due to the apprenticeship program, the smart metering program and hiring hall requirements;
- supporting the changes and additional clearing in the Forestry Program; and
- purchasing units rather than increase equipment rentals

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #30
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab3/Sch 1/Page 2-3, Table 1

On page 3 of the Board Report on Application of Cost Allocation for Electricity Distributors, the Board states: "To the extent that distributors can address influencing factors that are within their control (such as data quality), they should attempt to do so and to move revenue-to-cost ratios nearer to one."

a. Please advise whether Hydro One has sufficient data to set revenue to cost ratios to one.
b. If Hydro One does not have sufficient data,
    a. what data is missing?;
    b. what steps Hydro One is taking to collect this data?; and
    c. when will the missing data be available?
c. Please advise if Hydro One interprets the Board's Report on Application of Cost Allocation for Electricity Distributors to require a revenue to cost ratio of one if it is possible to do so;
d. If Hydro One does not interpret the board's Report to require a revenue to cost ratio of one if possible, please advise what requirement is imposed by the Board's Report?
e. If Hydro One does not interpret the Board's Report to require a revenue to cost ratio of one if possible, please identify all of the factors that Hydro One believes that it either has considered or is entitled to consider in determining whether to set revenue to cost ratios at something other than one.

Response

a. Hydro one, like all other distributors in Ontario, does not have interval hourly data for most of its customers. Specifically, for Residential and most General Service customers, load profiles used in the Cost Allocation study were developed based on Load Research and not actual hourly data for all customers. Good hourly data would be needed to establish with more confidence revenue to cost ratio equal to one for customer classes in a Cost Allocation Study. This is also the first time that a Cost Allocation Study results are being used in Ontario to establish cost based distribution rates. Establishing revenue to cost ratio equal to one for all customer classes will result in some customer classes having significant bill impacts. The suggested ranges of revenue to cost ratio by the OEB are an acceptable mechanism to mitigate bill impact resulting from the application of Cost Allocation Studies.

b. Hourly data for Residential and most General Service customers will be available in the future, once Smart meters are in service. There still would be some data for unmetered load that would need to be developed based on agreed upon assumptions for some customer classes.

c. Hydro One interprets the OEB range of revenue to cost ratio as recommended guidelines.

d. The Board report mentions the avoidance of rate shock as a criteria to be considered in establishing revenue to cost ratios, page 6, section 2.3.4 of OEB report.

e. Bill impacts was one criteria used by Hydro One in establishing the proposed revenue to cost ratio. Another criteria was to recover the proposed revenue requirement.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #31
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 3/Sch 1/Page 3

The evidence states that the revenue to cost ratio for Distributed Generation is to be changed from 1.63 to 1.0 "in support of Government policy to promote Distributed Generation in Ontario."

a. Please advise how government policy is relevant for the purposes of determining revenue to cost ratios;
b. Please advise what steps Hydro One took to discern government policy with respect to Distributed Generation;
c. Please advise what steps Hydro One took to discern government policy with respect to any other class of customer;
d. Please identify all policy matters that Hydro One considers relevant in setting revenue to cost ratios that depart from one.

Response

a. As mentioned in Exhibit H, Tab 11, Schedule 30, bill impact and recovering the revenue requirement are the main criteria considered in arriving at the proposed revenue to cost ratio. Additional criteria can and are sometimes used by distributors and regulators in cost allocation and rate design. In the book "Principles of Public Utility Rates" by Bonbright, Danielsen and Kamerschen, on page 382, a set of attributes is provided that should be considered in a sound rate structure.

   The Distributed Generation class is a very small class compared to the other customer classes. Even if the revenue to cost ratio would have been maintained at 1.63, the additional revenue to be collected, approximately $200,000, would have an insignificant impact on the other customer classes. Hydro One will implement any revenue to cost ratio for the Distributed Generation class or any other customer class that the OEB may decide is applicable.

b. Hydro One is aware of Government intention to promote Distributed Generation as is OEB staff. In proceeding EB-2007-0630 OEB and the staff discussion Paper issued July 13, 2007, the following is said: "Encouraging DG from renewable or clean energy sources is an important energy policy objective of the Government of Ontario, as

evidenced most recently by the Government's June 14, 2007 announcement on the Clean Energy Standard Offer Program."

Additionally, in the Minister letter dated August 18, 2005 to the OEB and OPA, the Minister requests that barriers be eliminated in order to promote small generation in Ontario.

Finally, in the Government Directive to OPA concerning the Integrated Power System Plan, dated June 13, 2006, specific mention is made to increase use of renewable energy sources.

c. No steps were taken to discern Government policy with respect to any other class.

d. Please see response to section a) above.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #32
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 3/Sch 1/Page 3

The evidence states that the revenue to cost ratios for Street Light and Sentinel Light classes is 0.7; the Urban General Service is 1.2; and the Sub-Transmission class is at 1.15.

a. For each of these classes, please specify why the revenue to cost ratio is not at one;
b. For each of these classes, please specify why Hydro One is proposing that some be at the higher or lower ends of ratios proposed by the Board.

Response

Please see Exhibit H, Tab 11, Schedule 31 for the criteria used by Hydro One to determine the recommended revenue to cost ratio. Exhibit G1, Tab 3, Schedule 1, page 2, line 13 to page 4, line 9 provide a detailed explanation on the proposed revenue to cost ratios for each customer class. The proposed revenue to cost ratios for all customer classes are within the recommended OEB revenue to cost ratio ranges.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #33
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

G1/Tab 3/Sch 1/Pages 3-4

The evidence states that the revenue to cost ratio for Acquired Residential customers is 0.88 because that is "considered to be the maximum that … this customer class can sustain."

a. Please advise of the research and analysis carried out by Hydro One to determine the amount this or any other customer class could sustain.

Response

Hydro One conducted no study to determine the maximum bill impact that customers can sustain. Hydro One is proposing to start addressing existing cross subsidies between customer classes. Bill impact to customer is a consideration in determining the proposed revenue to cost ratio. Recovery of Hydro One's revenue requirement is another criteria. If the OEB recommends in its decision that Hydro One should implement different revenue to cost ratios than those Hydro One is recommending, Hydro One will implement the OEB's recommendations.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #34
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 3/Sch 1/Page 4

The evidence states that the proposed revisions to revenue to cost ratios will lead to a shortfall of $2.5 million that Hydro One proposes to record in a deferral account for recovery at a future date "from all customers".

a. What is the rationale for seeking recovery from all customers as opposed to the customers that are under contributing to their cost?

Response

Hydro One will follow OEB recommendation as to how to recover the $2.5 million shortfall. It can be recovered from all customers, as Hydro one is proposing, or just from the R1 customers.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #35
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 3/Sch 1/Page 4

The evidence states that moving revenue to cost ratios to one would result in either unacceptable bill impacts or the need for an excessively long mitigation period.

a. Please advise whether Hydro One views the departure from a revenue to cost ratio of one to be a temporary transitional measure or an enduring feature of its rates;
b. If it is a temporary measure, what is the time frame for bringing revenue to cost ratios to one;
c. If it is a temporary measure, how will Hydro One ensure that it will be rectified before the imposition of performance-based regulation?
d. If Hydro One proposes that a departure will be enduring, what factors will it consider in any subsequent changes to revenue to cost ratios for specific customers?

Response

Hydro One has followed and will continue to follow OEB Guidelines in determining future revenue to cost ratio for customer classes.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #36
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 3/Sch 1/Page 5/Table 3

The total bill impact results in this table are difficult to understand. For example, the total bill impact of Sentinel lights is estimated at 118% when moving from an R/C of 0.62 to 1.00. At the maximum, it would seem that the total bill impact for this class could be no more than slightly over 60%.

a. Please provide a detailed explanation of how these calculations were made, including assumptions about the non-distribution portion of the total bills. Providing the electronic form of spreadsheet that was used for the calculations would be preferred.
b. Please add a column to this table with the average monthly total bill dollar impacts for each customer class and per unit for the un-metered Streetlight and Sentinel Light classes.

Response

a. The "Average impact %" listed in Table 3 are customer weighted average impacts for an average customer moving to the new rate class.

   For example, for the new UR class, the total bill impacts at a residential average of 1,000 kWh for the mapped UR, R1, R2, F1 and 12 Acquired Distributor customers are calculated from their existing rates to the new proposed rates. The impacts per composition rate class are weighted by the customers per rate class to derive the customer weighted average impact for the new UR class.

   Existing rates are per Approved Rate Schedules, and new Retail Transmission Service Charge per Exhibit G1, Tab 6, Schedule 1, and Rider 3 per Exhibit G1, Tab 5, Schedule 3.

b. The incremental monthly bill for an average customer is listed for the proposed Revenue-to-Cost Ratios. The value for the DGen class in Table 3 has been corrected.

	Proposed	Average	Ave Monthly	Average	R/C = 1	Average
	R/C	impact %	Total Bill Change	Per Customer		impact %
UR	1.00	3.4	$ 560,595	$ 3.60	1	3.4
R1	0.88	3.0	$ 1,193,062	$ 3.27	1	8.3
R2	1.04	1.0	$ 492,526	$ 1.37	1	(0.8)
Seasonal	1.00	9.7	$ 953,302	$ 6.17	1	9.7
UGe	1.20	(2.3)	$ (88,910.24)	$ (7.15)	1	(6.3)
UGd	1.00	0.3	$ (5,859.34)	$ (4.26)	1	0.3
Gse	1.08	0.5	$ 108,772	$ 1.18	1	(2.2)
GSd	1.02	(2.1)	$ (769,096)	$(112.29)	1	(2.7)
Dgen	1.00	(5.3)	$ (14,333.58)	$(176.96)	1	(5.3)
Street Light	0.70	5.0	$ 41,312	$ 8.61	1	21.7
Sentinel Lgt	0.70	25.0	$ 52,083	$ 1.78	1	118.1
ST	1.15	(4.7)	$ (68,550,008)	$ (198,121)	1	(5.0)

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #37
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 4/Sch 4/Page 2/Table 1

It is difficult to reconcile the figures in this table with the proposal to reduce the R/C ratio from 2.35 to 1.15 for Sub-transmission customers. Each of the volumetric charges proposed in Table 1 is more than half the current volumetric Charge, and a couple are higher than current rates (Specific LV and Distribution Line charges). Also, a fixed service charge is to be added.

a. Please provide a spreadsheet or table with discussion that illustrates how the new charges result in a lowering of the R/C ratio from 2.35 to 1.15.

Response

The Revenue/Cost ratio of 2.35 reflects customers from not only the existing LV class, but also customers from other existing classes. Please see Exhibit H, Tab 1, Schedule 151.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #38
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 5/Sch 1/Page 3

a. Please confirm that this proposal does not involve allocating smart meter costs to customer classes that will not receive smart meters or are currently using IESO approved revenue grade meters.

Response

The proposed allocator for the smart meter variance account is number of customers. This is consistent with the current OEB guidelines for recovery of the smart meter rider. The current Hydro One approved smart meter rider of $0.93 per month per customer is recovered from all metered customers. The initial smart meter rider of $0.30 per residential customer in 2006 was approved by the OEB in its decision on proceeding RP-2005-0020/EB-2005-0378, pages 46 and 47, section 6.3.4.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #39
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G1/Tab 3/Sch 1/Page 2/Table 1

The combination of a revised cost allocation and new customer classes makes it difficult to discern the actual impact on current customers of the combination of these two changes.

a. Please provide the existing revenue/cost ratios for T Class and Hydro One Embedded Direct Customers

Response

Using 2007 revenues and their corresponding share of the ST class allocated costs, the revenue to cost ratio for T-class is 7.2 and for Embedded Direct is 1.2

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #40
List 1

Interrogatory

Issue Number: 7.2
Issue: Is Hydro One's cost allocation appropriate?

Ref: G2/Tab 1/Sch 1/Page 4/Line 7

This sentence is confusing as written. Should "that" be inserted after "customers" on line 7?

Response

No. Exhibit G2, Tab 1, Schedule 1, page 4, lines 5 to 8 describe which customers will be included in the new General Service above 50 kW class. The new General Service above 50 kW class will include all customers that have not been reclassified to the ST class, are currently demand billed, and are in the following customer classes:

1. General Service single phase
2. General Service three phase
3. T-class with consumption below 500 kW
4. Farms

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #41
List 1

Interrogatory

Issue Number: 7.3
Issue: Are Hydro One's proposed rates appropriate?

Ref: G1/Tab 7/Sch 3/Page 2/Table 1

a. Please provide a version of this table that illustrates the impacts to customers of the Hydro One distribution charges only, including Retail Transmission Service Rates (RTSR) changes (e.g., excludes commodity charges).
b. With the table requested above, please state the underlying assumptions on charge determinants.

Response

a. ($ in millions)

Existing Rate Class	Total current bill with RAR	2008 changes in Dx-related charges	2008 changes in RTSR charges	Total Bill Impact of Dx and RTSR changes
UG	6.6	(1.1)	0.1	(14.9%)
acqd GS	51.2	(2.6)	0.3	(4.5%)
G3	41.2	(8.9)	0.7	(19.9%)
T	92.7	(16.5)	2.0	(15.7%)
acqd LU	28.7	(2.8)	(0.5)	(11.5%)
LDC	1,004.1	(2.2)	(19.4)	(2.2%)
Direct	229.8	(0.1)	(3.4)	(1.5%)

b. Monthly charge determinant assumptions for the table in "a":
For HVDS-high, HVDS-low, LVDS-low, Common Line: peak kW.
For Specific Line: km.
For RTSR-Network: peak kW during business days 7 AM to 7 PM.
For RTSR Connection: peak kW "anytime".

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #1 List 1

Interrogatory

Reference: Exhibit A, Tab 8, Schedule 3, page 5, Table 2

Question:

a) Provide a Copy of Schedule A to the SLA for 2008 Services from Networks to its affiliates, including Hydro One Inc. [Exhibit A Tab 8 Schedule 3 Appendix B Page 8/9]

b) Confirm that there is no Market for Services provided by Networks to Affiliates(Outbound Services).

c) Confirm that the fully allocated costs of Networks is used to set the transfer price.

d) Provide a sample calculation of the 2008 costs of Financial Services provided by Networks to affiliates, including
   i. Time studies/estimates
   ii. Fully allocated costs of providing the total services
   iii. The return on capital employed
   iv. Direct Allocations to affiliates
   v. Indirect allocations to affiliates using cost drivers

e) Provide a breakdown and description of the methodology as to how the costs of the services provided by Networks to affiliates are allocated between Transmission and Distribution.

f) Why are the costs of 2008 Financial Services provided to Hydro One Inc, Telecom and Brampton lower than in the past? Please provide a detailed explanation.

g) Compare reconcile your answers to part c and d) to the Service Level Agreements Schedule A for 2008 as requested in Part A

Response

a) Please see Attachment A.

b) Confirmed.

c) Confirmed.

d)

i. Sample time studies for Corporate Controller

Line #	Description	Cost Driver Allocator (If Applicable)	Tx OMA	Dx OMA	General T&D	General HOI Operations	Telecom	Brampton	Remote	Shareholder Only	TOTAL
	ACTIVITIES AND FUNCTIONS										
1	Accting policies; External reports; External audit / review				25.9%	0.0%	0.3%	0.3%	0.3%		26.8%
2	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections				18.3%	0.2%	0.3%	0.3%	0.3%		19.3%
3	Regulatory Finance Activities	Rate Base			12.0%	0.0%	0.1%	0.1%	0.1%		12.3%
4	Manage Inergi- General and Inergi- Finance contract				0.0%	0.0%	0.0%	0.0%	0.0%		0.0%
5	Revenue analysis and reporting	Revenue			5.5%	0.0%	0.0%	0.2%	0.0%		5.7%
6	Monitor and support Financial systems and Corporate accounting				23.5%	0.0%	0.4%	0.4%	0.4%		24.5%
7	Internal controls				5.6%	0.0%	0.1%	0.0%	0.1%		5.9%
8	Other departmental activities				0.0%	5.5%	0.0%	0.0%	0.0%		5.5%
9											
10											
11	TOTALS	0.0%	0.0%	0.0%	90.8%	5.7%	1.2%	1.3%	1.1%	0.0%	100.0%

ii. Fully allocated costs of providing the total services are included below.

iii. Not applicable.

iv. None.

v. Refer to table on following page:

Calculation of 2008 Costs of Financial Services Provided by Networks to Affiliates

Group	Function or Services	Activities Performed	Cost Driver	Networks	Telecom	Brampton	Remotes
Corp. Services	BIT(IMIT &OGCC)	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager	496,416.10	0.00	0.00	0.00
Corp. Services	BIT(IMIT &OGCC)	Support Asset Management activities and projects	Asset Manager	854,938.83	0.00	0.00	0.00
Corp. Services	BIT(IMIT &OGCC)	Provide operational support for Transmission and Distribution activities	Asset Manager	99,283.22	0.00	0.00	0.00
Finance	Taxation	Support Construction activities	Capital expenditures	27,459.75	522.86	523.48	521.11
Finance	Corporate Controller	Other departmental activities	Contr. Dept. Labor (Internal)	386,743.91	4,938.57	5,337.60	4,835.22
Finance	Corporate Controller	General Departmental activities	Contr. Dept. Labor (Internal)	192,414.69	2,457.06	2,655.59	2,405.64
Finance	Financial Strategy	Other department activities	Fin_Strat Dept. Labor (Internal)	374,273.44	5,030.61	4,003.23	3,613.53
Finance	Treasury	General departmental expenses	Fin_Treas Dept. Labor (Internal)	516,681.41	6,615.50	0.00	4,503.96
Network Executive	Internal Audit & Risk Mgmt	Finance	Finance Labor Costs (Internal)	448,330.63	5,758.28	3,903.84	4,167.50
Corp. Services	BIT(IMIT &OGCC)	Support Finance activities and projects	Finance Labor Costs (Internal)	0.00	0.00	0.00	0.00
Finance	Corporate Controller	Actuarial consultants	FTEs	735,840.65	8,829.97	0.00	5,078.03
Finance	Treasury	Fiduciary insurance policy	FTEs	54,069.49	648.83	0.00	373.13
Finance	Financial Strategy	Decision support for lines of business	Gross utility plant xB	623,227.64	27,827.58	0.00	0.00
Network Executive	Internal Audit & Risk Mgmt	Human Resources	HR Dept. Labor (Internal)	11,367.12	136.40	0.00	78.44
Network Executive	Internal Audit & Risk Mgmt	IMIT	IMIT Dept. Labor (Internal)	228,747.72	1,908.93	0.00	982.70
Corp. Services	BIT(IMIT &OGCC)	Other departmental activities	IMIT Dept. Labor (Internal)	141,618.87	1,181.83	0.00	608.40
Corp. Services	BIT(IMIT &OGCC)	General Departmental Expenses	IMIT Dept. Labor (Internal)	545,602.96	4,553.12	0.00	2,343.92
Finance	Corporate Controller	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)	0.00	0.00	0.00	0.00
Finance	Financial Strategy	Inergi Finance Contract Relationship	Inergi Finance_Total Blend (Internal)	263,122.19	0.00	0.00	0.00
Corp. Services	BIT(IMIT &OGCC)	Manage IT capital projects and IT strategy	Inergi IT (Internal)	1,828,221.39	20,905.78	0.00	9,675.33
Corp. Services	BIT(IMIT &OGCC)	Support Inergi operations	Inergi IT (Internal)	786,623.45	8,995.07	0.00	4,162.97
Finance	Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB	223,398.48	2,855.19	0.00	2,049.99
Network Executive	Internal Audit & Risk Mgmt	General Departmental Expenses	IntAudit Dept. Labor (Internal)	94,993.90	500.99	1,946.45	2,520.03
Network Executive	Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	1,925,502.12	2,895.49	49,223.36	66,596.31
Finance	Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	1,910,487.03	21,767.16	20,092.76	23,441.56
Finance	Corporate Controller	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend	1,360,560.09	21,974.74	22,193.72	18,508.93
Finance	Treasury	Insurance- Claims	Non-energy Rev_Assets Blend xB	3,058,301.92	39,629.86	0.00	17,290.24
Network Executive	Internal Audit & Risk Mgmt	Purchasing	Oper Maint Cap	136,593.10	3,807.15	3,231.98	1,142.36
Finance	Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	541,351.97	52,753.36	31,485.18	30,515.32
Finance	Taxation	Tax Planning	OperMaint Exp_Assets Blend	254,606.29	22,909.36	0.00	12,496.01
Finance	Taxation	Special Projects	OperMaint Exp_Assets Blend	39,050.04	0.00	0.00	0.00
Finance	Corporate Controller	Regulatory Finance Activities	Regulatory Dept. Labor (Internal)	884,081.64	6,697.59	6,697.59	6,697.59
Finance	Taxation	Support regulatory filings	Regulatory Dept. Labor (Internal)	41,653.38	0.00	2,603.34	1,301.67
Finance	Taxation	Other departmental activities	Tax Dept. Labor (Internal)	446,800.73	2,095.41	480.10	619.94
Finance	Taxation	Tax Consultants	Tax Dept. Labor (Internal)	122,700.11	10,293.93	4,688.53	6,054.25
Finance	Taxation	General Departmental activities	Tax Dept. Labor (Internal)	57,260.05	4,803.83	2,187.98	2,825.32
Finance	Treasury	IT Costs	Total Capital	0.00	0.00	0.00	0.00
Finance	Taxation	Support Debt issuance	Total Debt	4,975.35	83.12	125.80	22.41
Network Executive	Internal Audit & Risk Mgmt	Customers	Total Revenue	0.00	0.00	0.00	0.00
Finance	Corporate Controller	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend	1,727,977.75	26,790.35	26,790.35	26,790.35
Finance	Corporate Controller	Internal controls	Total Revenue_Assets Blend	415,250.47	8,371.99	3,348.79	8,371.99
Finance	Corporate Controller	Bill 198	Total Revenue_Assets Blend	0.00	0.00	0.00	0.00
Finance	Financial Strategy	Support business activities - Systems	Total Revenue_Assets Blend	1,189,698.04	0.00	0.00	0.00
Finance	Financial Strategy	Internal control compliance - Bill 198	Total Revenue_Assets Blend	543,326.66	11,296.35	31,133.83	28,103.10
Finance	Corporate Controller	Revenue analysis and reporting	Total Revenues	405,204.09	0.00	13,395.18	0.00
Corp. Services	BIT(IMIT &OGCC)	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	1,239,777.83	14,372.19	0.00	8,953.17
TOTAL FINANCIAL SERVICES				**25,238,534.50**	**354,208.42**	**236,048.68**	**307,650.44**

e) The Transmission and Distribution businesses do not share in costs of services provided by Networks to affiliates. The costs as shown for the Distribution business are net of the costs that are paid for by the Affiliates for services received and are charged per the Rudden Study.

f) The costs of 2008 Financial Services provided to Hydro One Inc, Telecom and Brampton are lower than in the past due to a number of factors:

- Reduced Corporate Controller activities supporting Brampton
- Reduced decision support activities for Telecom
- Reduced planned audits for Telecom and Brampton

g) The total costs for services to be provided by Hydro One Networks for Financial Services as shown in (d) above match the costs as per Schedule A of the SLA in (a) above.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

	SERVICES TO BE PROVIDED BY HYDRO ONE NETWORKS INC. TO: (in $Thousands)			
SERVICES	**Hydro One Inc.**	**Hydro One Remote Communities Inc.**	**Hydro One Telecom Inc.**	**Hydro One Brampton Networks Inc.**
General Counsel and Secretary Services	**75**	**220**	**75**	**150**
Financial Services	**57**	**308**	**354**	**236**
Corporate Services		**89**	**146**	**28**
Telecommunication Services		**118**	**195**	
Other Services		**479**	**1,086**	
Totals	**132**	**1,214**	**1,856**	**414**

DESCRIPTION OF SERVICES:

The following provides a generic description of all Services to be provided by the Services Provider.

GENERAL COUNSEL AND SECRETARY SERVICES

The Services Provider shall provide the Services Recipient with professional legal advice and input which shall include, but not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licenses), contracts, and environmental and health and safety issues. The Services Provider will also provide services regarding the protection of assets and management of security risks.

FINANCIAL SERVICES

The Services Provider shall provide financial services support to the Services Recipient by providing timely and reliable financial information. The Services Provider will also provide services relating to business planning, budgeting and financial reporting. As required, services relating to treasury/pension/investor relations, taxation, internal audit and risk management, insurance, financial systems and services, cost and inventory accounting and decision support will also be provided. Other financial services such as transaction processing (accounts payable and receivable), and fixed asset and general accounting will also be provided.

CORPORATE SERVICES

The Services Provider shall provide corporate services in three main areas:

- facility management and support services – management services related to acquisition, maintenance, protection and disposal of the Services Recipient's portfolio of land holdings as well as facilities and buildings management, including office accommodation and all related support and services; services related to the appraisal, negotiation and acquisition of real estate rights including: full ownership, easements, leases, licenses, and permits, as well as special projects.
- human resource services – provision of human resource policy, strategy and standards to meet legal and other requirements. This includes staff planning, leadership development, succession planning and change management, as well as labour relations services, pay equity, diversity, health services and performance management, compensation, health and benefits programs and administration of payroll, benefits plans and incentive programs.
- corporate communications – provision of strategy, program and support for corporate communications, public affairs and media relations, as well as corporate and shareholder relations and strategy and programs related to internal communications.

TELECOMMUNICATIONS SERVICES

The Services Provider shall provide the Services Recipient with various telecommunications-related services including field and engineering, logistics, corporate, construction, telecommunication and information technology services.

OTHER SERVICES

The Services Provider shall provide the Services Recipient with:

- Supply Procurement – provision of demand planning, management and procurement, vendor and inventory management, process development, data management, warehousing, waste management and investment recovery.
- Customer Services Operation – provision of bill production and dispatch and settlements service, as well as data services related to field-based service orders.
- Information Management – provision of infrastructure operations, including a variety of activities such as system testing and integration, Internet and database management services, as well as services related to mainframe infrastructure operations, end user and desk-top support.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2 List 1

Interrogatory

Reference: Exhibit A, Tab 8, Schedule 3, page 5, Table 2

Question:

a) Provide a Copy of Schedule A to the SLA for 2008 Services from Hydro One Inc. to its affiliates, including Networks [Exhibit A Tab 8 Schedule 3 Appendix A Page 8/9]].

b) Confirm that there is no Market for Services provided to Networks by Hydro One Inc and Telecom (Inbound Services).

c) Confirm that the fully allocated costs of Hydro One Inc. and Telecom is used to set the transfer prices.

d) Provide a sample calculation of the 2008 costs of President/CEO Services provided to Networks and other affiliates, including
   i. Time studies/estimates
   ii. Fully allocated costs of providing the total services
   iii. The return on capital employed
   iv. Direct Allocations to affiliates
   v. Indirect allocations to affiliates using cost drivers
   vi. Why are the costs of 2008 Corporate Services provided to Networks lower than in the past? Please provide a detailed explanation

e) Why are the Telecom Services provided to Networks higher in cost than 2006 and 2007 Please provide a detailed explanation and highlight the cost drivers and/or expanded service levels.

f) Provide details of the Basis of the 2008 allocation of Corporate Services and Telecom Services to Transmission and Distribution.

g) Compare/reconcile your answers to part c, d, and e to Schedule A of the 2008 Service Level Agreements either as requested in part A, or filed at Exhibit A-8-3, Appendix E.

Response

a) Please see Attachment A.

b) Confirmed.

c) Confirmed.

d) We are assuming that this question refers to Exhibit A, Tab 8, Schedule 3, page 7, Table 3.

HYDRO ONE COMMON CORPORATE COST MODEL

YEARLY COST DISTRIBUTION

PRESIDENT/CEO Services

			Total 2008 Activity Cost to Business Unit						
Function or Services	Activities Performed	Cost Driver	Tx	Dx	Telecom	Brampton	Remotes	Share-holder Only	Total
Chair	OVERALL ASSIGNMENT OF TIME	Non-energy Rev_Assets Blend	168,762	120,142	3,090	6,180	7,725	3,090	308,988
Chair	General Departmental Expenses	Non-energy Rev_Assets Blend	13,972	9,946	310	637	135	0	25,000
Board	OVERALL ASSIGNMENT OF TIME	Non-energy Rev_Assets Blend	0	0	0	0	0	0	0
Board	Audit Fee	Total Revenue_Assets Blend xBxTxR	320,320	377,209	0	0	0	0	697,529
Board	General departmental expenses	Non-energy Rev_Assets Blend	322,727	229,750	7,159	14,711	3,123	0	577,471
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct	41,573	33,874	616	616	308	0	76,987
President/CEO Office	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct	166,293	135,498	2,464	2,464	1,232	0	307,949
President/CEO Office	Develop and maintain relationships with major customers and customer groups	All Direct	166,293	135,498	2,464	2,464	1,232	0	307,949
President/CEO Office	Develop and maintain relationships with regulators, shareholder, lenders	All Direct	166,293	135,498	2,464	2,464	1,232	0	307,949
President/CEO Office	Monitor, assess and remediate risks to operational and financial performance	All Direct	83,146	67,749	1,232	1,232	616	0	153,975
President/CEO Office	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct	166,293	135,498	2,464	2,464	1,232	0	307,949
President/CEO Office	Plan for management succession	All Direct	41,573	33,874	616	616	308	0	76,987
President/CEO Office	General Departmental Expenses	Pres_CEO Dept. Labor (Internal)	162,000	132,000	2,400	2,400	1,200	0	300,000
TOTAL			1,819,243	1,546,536	25,277	36,246	18,342	3,090	3,448,734

Time Study for Chairman:

Line #	Description	Cost Driver Allocator	Tx OMA	Dx OMA	General T&D	General HOI Operations	Telecom	Brampton	Remote	Shareholder Only	TOTAL
ACTIVITIES AND FUNCTIONS		(If Applicable)									
1	OVERALL ASSIGNMENT OF TIME				93.5%		1.0%	2.0%	2.5%	1.0%	100.0%
2											0.0%
3											0.0%
4											0.0%
5											0.0%
6											0.0%
7											0.0%
8											0.0%
9											0.0%
10	OTHER DEPARTMENT ACTIVITIES										0.0%
11	TOTALS		0.0%	0.0%	93.5%	0.0%	1.0%	2.0%	2.5%	1.0%	100.0%

Time Study for Board:

Line #	Description	Tx OMA	Dx OMA	General T&D	General HOI Operations	Telecom	Brampton	Remote	Shareholder Only	TOTAL
ACTIVITIES AND FUNCTIONS										
1	OVERALL ASSIGNMENT OF TIME			93.5%		1.0%	2.0%	2.5%	1.0%	100.0%
2										0.0%
3										0.0%
4										0.0%
5										0.0%
6										0.0%
7										0.0%
8										0.0%
9										0.0%
10	OTHER DEPARTMENT ACTIVITIES									0.0%
11	TOTALS	0.0%	0.0%	93.5%	0.0%	1.0%	2.0%	2.5%	1.0%	100.0%

Time Study for President/CEO:

Line #	Description	Tx OMA	Dx OMA	General T&D	General HOI Operations	Telecom	Brampton	Remote	Shareholder Only	TOTAL
ACTIVITIES AND FUNCTIONS										
1	Establish performance targets for safety, customer service, reliability	2.70%	2.20%			0.04%	0.04%	0.02%		5.0%
2	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	10.80%	8.80%			0.16%	0.16%	0.08%		20.0%
3	Develop and maintain relationships with major customers and customer groups	10.80%	8.80%			0.16%	0.16%	0.08%		20.0%
4	Develop and maintain relationships with regulators, shareholder, lenders	10.80%	8.80%			0.16%	0.16%	0.08%		20.0%
5	Monitor, assess and remediate risks to operational and financial performance	5.40%	4.40%			0.08%	0.08%	0.0%		10.0%
6	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	10.80%	8.80%			0.16%	0.16%	0.08%		20.0%
7	Plan for management succession	2.70%	2.20%			0.04%	0.04%	0.02%		5.0%
8										0.0%
9										0.0%
10	OTHER DEPARTMENT ACTIVITIES									0.0%
11	TOTALS	54.0%	44.0%	0.0%	0.0%	0.8%	0.8%	0.4%	0.0%	100.0%

i. As shown above.
ii. Fully allocated costs of providing the total services are shown above.
iii. None.
iv. As shown in calculation above.
v. As shown in calculation above.
vi. There are no Corporate Services provided **to** Networks in Exhibit A-8-3 Table 2. The 2008 Corporate Services provided **by** Networks in Exhibit A-8-3 Table 2 are higher, not lower, than in the past. The increase in Corporate Services costs for services provided by Networks to Remotes, Telecom and Brampton are due to a number of factors:
    - Increase in spending relating to HR development programs
    - Introduction of new Corporate Security programs

e) Telecom Services provided **to** Networks are reflected in Exhibit A-8-3 Table 3 (page 7) rather than Table 2 (page 5). This shows an increase from $6,361 in 2006 to $8,656 in 2007 to $9,000 in 2008. The single biggest impact to HONI in 2007 is the inclusion of a labour and pension adjustment. Hydro One Telecom had previously absorbed these increases and not passed them along to HONI. The increase in 2008 costs is primarily due to labour escalation.

f) 2008 Corporate Services allocation to Transmission & Distribution:

HYDRO ONE COMMON CORPORATE COST MODEL
YEARLY COST
DISTRIBUTION
CORPORATE SERVICES

				2008	Year 1 Total Activity Cost to Business Unit	
Group	Function or Services	Activities Performed	Cost Driver	Total $ Budget	Tx	Dx
Corp. Services	HR	Administer Compensation & Benefits Programs	FTEs	6,417,828	305,242	332,577
Corp. Services	HR	Decision support	FTEs		202,815	220,977
Corp. Services	HR	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		388,945	423,775
Corp. Services	HR	Administer Pension Plan	FTEs		388,945	423,775
Corp. Services	HR	Administer Inergi HR	Inergi HR (Internal)		112,382	122,447
Corp. Services	HR	Consulting support to LOBs and corporate functions	FTEs		1,317,277	1,435,242
Corp. Services	HR	Director	HR Dept. Labor (Internal)		298,809	325,568
Corp. Services	Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs	1,534,571	307,549	335,090
Corp. Services	Labour Relations	Negotiate with Bargaining Units	FTEs		96,385	105,016
Corp. Services	Labour Relations	Participate in grievance and arbitration filings	FTEs		255,336	278,201
Corp. Services	Labour Relations	Participate in OLRB hearings	FTEs		61,510	67,018
Corp. Services	Labour Relations	Internal vacancy management	FTEs		0	0
Corp. Services	Corp. Security	Provide Security Services for Company Assets	Assets	2,453,618	1,256,061	671,825
Corp. Services	Corp. Security	Theft of Power Program (Recovery of stolen electricity)	Direct Dx	2,453,618	0	481,530
Corp. Services	SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)	888,859	426,262	448,165

HYDRO ONE COMMON CORPORATE COST MODEL
YEARLY COST
DISTRIBUTION
CORPORATE SERVICES

				2008	Year 1 Total Activity Cost to Business Unit	
Group	Function or Services	Activities Performed	Cost Driver	Total $ Budget	Tx	Dx
Corp. Services	BIT(IMIT &OGCC)	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	6,068,234	595,584	644,194
Corp. Services	BIT(IMIT &OGCC)	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		280,608	215,808
Corp. Services	BIT(IMIT &OGCC)	Support Asset Management activities and projects	Asset Manager		579,923	275,016
Corp. Services	BIT(IMIT &OGCC)	Support Finance activities and projects	Finance Labor Costs (Internal)		0	0
Corp. Services	BIT(IMIT &OGCC)	Provide operational support for Transmission and Distribution activities	Asset Manager		67,346	31,937
Corp. Services	BIT(IMIT &OGCC)	Manage IT capital projects and IT strategy	Inergi IT (Internal)		735,575	1,092,647
Corp. Services	BIT(IMIT &OGCC)	Support Inergi operations	Inergi IT (Internal)		316,494	470,130
Corp. Services	BIT(IMIT &OGCC)	Other departmental activities	IMIT Dept. Labor (Internal)		68,751	72,868
Corp. Services	BIT(IMIT &OGCC)	General Departmental Expenses	IMIT Dept. Labor (Internal)		264,872	280,731
TOTAL					8,326,669	8,754,537

2008 Telecom Services allocations to Transmission & Distribution:

HYDRO ONE COMMON CORPORATE COST MODEL
YEARLY COST
DISTRIBUTION
TELECOM SERVICES

				2008	Year 1 Total Activity Cost to Business Unit	
Group	Function or Services	Activities Performed	Cost Driver	Total $ Budget	Tx	Dx
Telecom Services	Telecom Services	Operations and Carrier Management	Telecom Services	17,080,000.00	2,055,814.59	2,234,256.86
Telecom Services	Telecom Services	Data Network Services – Admin	Workstations		2,088,853.15	2,259,339.35
Telecom Services	Telecom Services	Voice Services	Telephones		1,602,212.13	1,745,739.86
Telecom Services	Telecom Services	Field Services	Telephones		2,288,203.25	2,493,182.73
TOTAL					8,035,083.13	8,732,518.81

g) The total costs for services to be provided by Hydro One Inc. to Hydro One Networks and other affiliates as shown in (d) above match the costs as per Schedule A of the SLA in (a) above.

Schedule "A"

The annual cost for the performance of the Services to be delivered is summarized as follows:

Services	SERVICES TO BE PROVIDED BY HYDRO ONE INC. TO: (in $Thousands)			
	Hydro One Networks Inc.	Hydro One Remote Communities Inc.	Hydro One Telecom Inc.	Hydro One Brampton Networks Inc.
General Counsel & Secretary (including Corporate Executive Office)	907	24	10	19
President / CEO / Chairman Services	3,366	18	25	36
Chief Financial Office Services (including Strategic Financial services)	804	7	28	38
Totals	5,077	49	63	93

DESCRIPTION OF SERVICES:

General Counsel and Secretary

The Services Provider shall provide the Services Recipient with professional legal advice and input. This advice shall include, but shall not be limited to, interpretation and analysis of legislation and regulations, advice concerning corporate structure and governance, development of regulatory instruments (licences), contracts, and environmental and health and safety issues. The Services Provider will also provide guidance on business ethics and support in the form of a business code of conduct.

President / CEO / Chairman services

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate goals are achieved.

Chief Financial Office services (including Strategic Financial services)

The Services Provider shall provide the Services Recipient with strategic direction and management in an attempt to ensure that the Services Recipient's corporate financial goals are achieved.

The Services Provider shall provide the Services Recipient with strategic approval with respect to investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting will also be provided by the Services Provider to the Services Recipient as required by the Services Recipient.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3 List 1

Interrogatory

Reference: Exhibit A, Tab 14, Schedule 1, Sections 1.0-4.0 Tables

Question:

a) Confirm which Business Planning/Economic/Interest rate assumptions will be updated
   i. prior to hearing, and
   ii. prior to issuance of the Boards Decision/rate Order

b) Provide the latest Global Insight Dx O&M and Capital Indices for 2008 and highlight the impact that any material change will have on 2008 costs and Revenue Requirement.

c) Provide the HO's latest summary of Consensus Forecast Bond Rates and ST interest rates. Compare the impact of the changes on the 2008 Cost of Capital and revenue requirement.

d) Confirm that the Tax rates shown in Section 4.0 the final rates, including Capital tax.

e) What will HO do if Provincial tax rates change in the Spring 2008 Provincial Budget?

Response

a. Hydro One is not planning on updating its 2008 Distribution rate filing for changes in planning assumptions. If directed by the Board as part of the Rate Decision, Hydro One will incorporate any requested changes in planning assumptions in the final revenue requirement calculation.

b. The following table lists the 2008 Dx O&M and Capital Indices assumptions used in the 2008 Distribution rate application and the latest Global Insights report which was issued in March 2008. The latest indices are higher compared to the indices used in the application which would result in a higher 2008 costs and revenue requirement.

	2008 Filed	Per Latest Global Insight Report
Dx cost escalation for Construction (%)	1.9%	4.7%
Dx cost escalation for Operations & Maintenance (%)	0.9%	3.6%

c. The interest rate summary shown below is based on the March 2008 Consensus forecast, actual term spreads from February 2008, and Hydro One's February 2008 credit spreads.

	2008
HO1 5-Year Bond Rate (%)	4.40
HO1 10-Year Bond Rate (%)	4.99
HO1 30-Year Bond Rate (%)	5.51
90-Day Banker's Acceptance Rate (%)	3.52

The change in Hydro One forecast bond rates for 2008 would not change the cost rate for Third Party long-term debt from the 5.71% shown in Exhibit B1, Tab 1, Schedule 1, Page 3. Hence, there would be no impact on Hydro One Distribution's revenue requirement.

d. The tax rates shown for 2008 in Section 4.0 are consistent with the assumptions used in preparing the 2008 Distribution rate filing.

e. See response to Exhibit H, Tab 1, Schedule 93 part a.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4 List 1

Interrogatory

Reference: Exhibit A, Tab 14, Schedule 3, page 4

Preamble: *Hydro One Distribution's load forecast has incorporated the Board's latest decision for Hydro One Transmission Rate case (EB-2006-0501) to include 350 MW of natural conservation in the provincial CDM target of 1350 MW for 2007. The load forecast in 2008 also accounts for 251 MW of CDM program impacts assumed in the OPA's IPSP that was filed with the Board on August 29, 2007*

Question:

a) Confirm that the 350 MW of natural conservation is a minimum and provide the range of estimates.

b) Provide details of the assumptions underlying the 251 MW of CDM in the IPSP and how this relates to HO service areas and customers.

c) Confirm that OPA IPSP CDM forecast are regional and not utility-specific

Response

a) Hydro One Distribution has not seen any detailed research and analysis done to date on natural conservation in Ontario, and as a result can not confirm that 350 MW of natural conservation for the province is a minimum or maximum. Hydro One Distribution's own estimate of natural conservation for the province is about 0.4% a year and therefore considers the estimate of 350 MW of natural conservation over a 3-year period (2005-2007) to be reasonable.

b) Details related to the 251 MW of CDM in the IPSP can be found in EB-2007-0707, Exhibit D, Tab 4, Schedule 1, Attachment 4 filed by the OPA with the Board on August 29, 2007. While no utility-specific estimates were available from the OPA, Hydro One Distribution believes the provincial CDM impacts in 2008 should at least be proportionately applicable to its customers. For the latest information on 2008 CDM programs, please see the response provided in Exhibit H, Tab 2, Schedule 8. For CDM results achieved to date by Hydro One customers, please see Attachment A of Exhibit H, Tab 1, Schedule 105.

c) Yes, the IPSP CDM forecasts released by the OPA to date are regional and not utility-specific.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5 List 1

Interrogatory

Reference: Exhibit A, Tab 14, Schedule 3, pages 8-9 and Table 2

Preamble: *Hydro One Distribution does not currently have the data required to do a bottom-up analysis of the CDM impact on Hydro One's load forecast from the various CDM programs driven by various sources such as the Ontario Power Authority, Provincial Government and Federal Government.*

Question:

a) Does Table 2 (and Table 4 on Page 20) reflect HO's estimates of 2006-2008 CDM load reductions in its service area and embedded LDCs as filed in its reports with the Board? Please discuss and compare 2008 to the 251 MW in the OPA IPSP.

b) Provide the corresponding MW reductions (Summer and Winter peak).

c) Provide the impact on forecast revenues and the revenue sufficiency/deficiency of a 50GWh change in Residential/GS CDM energy consumed and a corresponding impact of a 10MW reduction in forecast peak load.

d) Comment further regarding when HO will comply with the Board's Direction for a bottom up forecast of CDM Impacts on Energy and Demand.

Response

a) Yes, the CDM impacts in Table 2 and Table 4 reflected available CDM program results and information filed with the Board at the time when the CDM forecast was prepared. At the time when Hydro One Distribution forecast the 2008 CDM impacts, detailed 2008 programs were not yet available. As a result, Hydro One Distribution used the consumption share of the provincial total to prorate the 251 MW of CDM impacts for its customers. For the latest information on 2008 CDM programs, please see the response provided in Exhibit H, Tab 2, Schedule 8.

b) The requested information is provided below:

CDM Impact on Hydro One Distribution Peak Load
(MW)

	Winter			Summer		
Year	Retail	Embedded	Total	Retail	Embedded	Total
2006	44	34	78	44	34	78
2007	67	52	119	68	53	121
2008	99	75	174	101	77	178

c) The revenue impact of a 50 GWh reduction in Residential/GS CDM energy consumed is estimated to be about $1.2 million. The corresponding impact of a 10 MW reduction in peak load is estimated to be about $90,000 per month or about $1.1 million per year.

d) Hydro One Distribution has completed a detailed bottom-up analysis of CDM program results achieved to date (see Attachment A in Exhibit H, Tab 1, Schedule 105). Hydro One Distribution will continue to use the best available information, including bottom-up analysis, to forecast the CDM impacts.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6 List 1

Interrogatory

References: Exhibit A, Tab 14, Schedule 3, page 7;
Exhibit A, Tab 14, Schedule 3, pages 8-9

Preamble: *Approximately nine to ten thousand customers are added to Hydro One Distribution's customer base on an annual basis. Customer growth in 2007 and 2008 is expected to be approximately 11,000 and 9,400 respectively (2007 customer growth includes an addition of 1,100 customers from Terrace Bay). This compares to an average of about 12,000 customers that were added per year in the period 2002-2006. The lower figure for 2008 is attributed to a reduction in housing starts.*

Question:

a) Provide the Housing Start Forecast for HO service areas (and if available, actuals) for 2004-2007.

b) Provide the Housing Start Actual 2007 and Forecasts for Ontario for 2008 from Consensus Forecasts, the major Banks and from the Conference Board of Canada

Response

a) Hydro One does not have any housing starts forecast specific to its service areas.

b) The housing start actual for 2007 is currently estimated to be about 68,000. The consensus forecast for housing start for 2008 is estimated to be about 64,000 (see the table below)

Consensus Forecast of Housing Starts

	2007	**2008**
Global Insight (Feb 2008)	68.0	61.8
Conference Board (Feb 2008)	68.1	67.1
U of T (Jan 2008)	68.1	64.0
C4SE (Jan 2008)	68.8	66.3
CIBC (Oct 26, 2007)		63.0
BMO (Winter 2008)	68.1	61.5
RBC (Feb 2008)	68.1	66.4
Scotia (Feb 21, 2008)	68.0	62.0
TD (Jan 2008)	68.7	64.4
Average	**68.2**	**64.1**

Prepared on February 29, 2008

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7 List 1

Interrogatory

Reference: Exhibit A, Tab 14, Schedule 3, page 20, Table 4

Question:

a) Provide the 2008 Load Forecast without CDM, but including natural conservation
   i. Total Energy and Demand
   ii. Residential Energy and Demand

b) Provide the corresponding 2006-2007 Winter/Summer peak MW with and without CDM.

c) Indicate the Average Dx Loss factors for 2006-2008.

d) Indicate the Residential average use and total consumption actual vs forecast for 2006 and 2007 and forecast 2008.

Response

a) The requested information for 2008 is provided below:
   i. Total energy is estimated to be 41,601 GWh and total demand, 7,071 MW.
   ii. Residential energy is estimated to be 10,959 GWh and residential demand, 2,545 MW.

b) The requested information is provided below:

Hydro One Distribution Peak Load Before and After CDM

(MW)

	Before Deducting CDM Impact		After Deducting CDM Impact	
Year	Winter Peak	Summer Peak	Winter Peak	Summer Peak
2006	6,972	6,112	6,894	6,035
2007	6,988	6,119	6,869	5,998

c) Please see the response to Exhibit H, Tab 2, Schedule 3

d) The requested information is provided below. The 2006 forecast was prepared in early 2006 for the year 2006. The 2007 actual is not yet available.

Residential Average Usage and Total Consumption

Year	Average Usage (kWh)	Total Consumption (GWh)
2006 (Forecast)	11,091	10,587
2006 (Actual)	11,082	10,707
2007 (Forecast)	10,828	10,581
2008 (Forecast)	10,785	10,643

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8 List 1

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 1, page 5, Table 1

Question:

a) Provide an updated version of Table 1 showing 2007 actual CSIs and forecast 2008 CSIs.

b) Indicate whether the number of ER events in 2004-2007 were System or Weather related.

c) Provide a short summary of HO Dx's response to OEB Staffs Proposed changes to CSIs

Response

a.

Table 1
Customer Service Indicators

Performance Measure	OEB Target	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 OEB Target
Appointments (% met as agreed with customer)	**≥ 90**	**93**	**90**	**92**	**93**	**≥ 90**
Connection of New Services (% completed in ≤ 5 days)	**≥ 90**	**94**	**93**	**91**	**94**	**≥ 90**
Emergency Response (% responded to in ≤ 120 min)	**≥ 80**	**91** **90***	**86** **73***	**92** **65***	**88** **82***	**≥ 80**
Telephone Accessibility (% answered in ≤ 30 seconds)	**≥ 65**	**74**	**72**	**77**	**78**	**≥ 65**
Underground Cable Locates (% completed in ≤ 5 days)	**≥ 90**	**93**	**93**	**92**	**93**	**≥ 90**
Written Response to Inquiries (% responded to in ≤ 10 days)	**≥ 80**	**100**	**100**	**100**	**100**	**≥ 80**

*Emergency Response results including the impact of Force Majeure.

b. Emergency response is defined as "At a minimum, emergency trouble calls (e.g. fire, ambulance, police) will be responded to within 120 minutes in rural areas," as per Section 15.1.6 of the 2006 Electricity Distribution Rate Handbook. This means that Hydro One crews responded to events such as house fires, motor vehicle accidents involving our hydro poles, conductor on the ground due to the wind blowing a tree over, etc. The events were weather-related, a result of an action from the public or due to the failure of equipment on the distribution system.

c. Hydro One provided comment on the OEB Staff Discussion Paper in respect of the development of the Service Quality Regulation ("SQR") for electricity distributors in a letter to the Board secretary dated February 4, 2008, provided as an Attachment A to this response.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9 List 1

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 1, page 7, Table 2

Question:

a) Provide an updated version of Table 2 showing 2007 actual SQIs and forecast 2008 SQIs.

b) Hydro One deems a *force majeure* to have occurred when 10% or more of Hydro One customers have been interrupted by an event.
   i. Provide the Industry Technical Definition of a Force Majeure event (if different) and
   ii. Provide a summary whether the number and duration of events in 2004-2007 were system or weather related.

c) Provide a short summary of HO Dx's response to OEB Staffs Proposed changes to SQIs.

Response

a. Table 2 Service Reliability Indicators

Performance Measure	2004 OEB Tgt	2004 Act	2005 OEB Tgt	2005 Act	2006 OEB Tgt	2006 Act	2007 OEB Tgt	2007 Act	2008 OEB Tgt
SAIFI *Frequency of Interruptions* (#of interruptions per customer)	**≤ 3.0**	**3.1**	**≤ 3.1**	**2.9**	**≤ 3.1**	**2.9**	**≤ 2.9**	**3.6**	**≤ 3.6**
SAIFI including *Force Majeure*		**3.2****		**3.9†**		**5.2††**		**4.1†††**	

Performance Measure	2004 OEB Tgt	2004 Act	2005 OEB Tgt	2005 Act	2006 OEB Tgt	2006 Act	2007 OEB Tgt	2007 Act	2008 OEB Tgt
SAIDI *Duration of Interruptions* (hrs of interruption per customer)	**≤ 9.4**	**6.5**	**≤ 9.4**	**8.0**	**≤8.0**	**7.1**	**≤ 8.0**	**8.6**	**≤ 8.6**
SAIDI including *Force Majeure*		**6.9****		**14.5†**		**28.4††**		**11.4†††**	
CAIDI *Average Interruption Time* (#of hrs per interruption)	**≤ 3.1**	**2.1**	**≤ 3.0**	**2.8**	**≤ 2.6**	**2.4**	**≤ 2.8**	**2.4**	**≤ 2.4**
CAIDI including *Force Majeure*		**2.2****		**3.7†**		**5.5††**		**2.8†††**	

** See Exhibit A, Tab 15, Schedule 1 for details on "2004 Force Majeure Events"
† See Exhibit A, Tab 15, Schedule 1 for details on "2005 Force Majeure Events"
†† See Exhibit A, Tab 15, Schedule 1 for details on "2006 Force Majeure Events"
† †† See write-up below for details on "2007 Force Majeure Events"

2007 Force Majeure Events

In 2007 there were three force majeure events that met the 10% of customers affected definition. The storms occurred on March1-3, June 8-9 and July 8-12. Each of those days, respectively they interrupted the following percentages of customers: 16%, 16% and 18%.

March 1-3 – This storm consisted of freezing rain, ice pellets, snow, rain and winds gusting up to 70 km/hr, affected 16% or about 184,000 customers from southwestern Ontario to the Ottawa River.

June 8-9– A fast moving band of thunderstorms from Texas to Sault Saint Marie caused widespread damage and interruptions throughout Mid Western, Eastern United States and Ontario. The thunderstorms moved west to east with heavy rain, strong winds and hail affecting 16% or about 190,000 customers.

July 8-12 – A heavy band of thunderstorms North Western Ontario to South Eastern

Ontario caused widespread damage and interruptions throughout Hydro One's service territory affecting 18% or about 217,000 customers.

The effect of these storms resulted in a contribution to the annual SAIDI of 2.8 hours and annual SAIFI of .5 interruptions per customer, with a CAIDI of about 5.6 hours.

b.

i. There is no "Industry Technical Definition of a Force Majeure event" though the concept of excluding events beyond the control of the utilities exists within the industry.

ii. See answer to question a). All force majeure events were weather-related except the August 14, 2003 Blackout.

c. Please refer to interrogatory response in Exhibit H, Tab 12, Schedule 8, part c.

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Filed: April 4, 2008
EB-2007-0681
Exhibit H-12-8
Attachment A

BY COURIER

February 4, 2008

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

Re: Service Quality Regulation for Electricity Distributors
Board File No.: EB-2008-0001
Hydro One Networks Comments on Staff Discussion Paper

Hydro One Networks Inc. ("Hydro One") welcomes the opportunity to comment on the OEB ("Board") Staff Discussion Paper ("SDP") in respect of the development of the Service Quality Regulation ("SQR") for electricity distributors as outlined in the Board's communication of January 4, 2008.

Hydro One's comments are provided in the form of (i) general comments addressing the context for setting service quality standards and regulation, as well as outlining some key themes meant to assist the Board in developing the SQR metrics and standards, (ii) specific comments related to the proposals put forward in the SDP that are of concern to Hydro One, and (iii) responses to questions posed by Board Staff in the SDP.

1. General Comments

1.1. Setting the Context

Hydro One supports the Board's effort to move forward with SQR in the electricity distribution sector in Ontario. A set of service quality standards based on clear definitions is paramount to ensuring that utilities understand the intent behind the selected metrics, and in turn, collect and report the relevant information to implement this form of regulation in a consistent manner.

SQR is a necessary regulatory tool that enables the Regulator to assess utilities' performance in consistently providing the appropriate level of distribution services to electricity customers. In this

respect the move towards the setting of clear standards is consistent with the utilities' drive to maintain high levels of customer satisfaction.

In as much as Hydro One supports the Board's move to establishing SQR, we encourage the Board to do so in an orderly manner. Such an approach will provide the directional intent whilst at the same time allowing time for industry to adjust to new definitions, increased collection of data, analysis, reporting and compliance with standards. This will ensure that changes are effectively and efficiently implemented and that sufficient learning time is allowed to minimize misunderstandings and inconsistency to the greatest extent practicable.

In the following sections Hydro One offers commentary on the scope, need for change, application and impacts of the proposal for implementing SQR standards and suggests these be carefully examined to allow for an orderly transition from status quo to the desired goals for service quality regulation.

1.2. Scope of SQR Proposal

The SDP proposes to do three things, namely:

- Revise the definitions of SQR metrics.
- Increase the number of Service Quality Index ("SQI") metrics.
- Increase SQI targets.

In short, the Board proposes not only to change the foundation on which SQR will be based (definitions and number of measurable metrics), but to also simultaneously raise the bar for utility performance by increasing the minimum standards. Taken together, these proposals will result in very significant changes to the status quo, which if not handled in an orderly manner may ultimately detract from achieving the timely implementation of SQR standards.

To elaborate, the distribution industry generally recognizes that today's definitions of SQI metrics are insufficiently precise, resulting in ambiguity and utilities' misinterpretation of the requirements. Consequently data collection, analysis and performance reporting may not synchronize with what is expected. For example, individual Utility interpretation of the current definition of the Call Answer Service Level, has led to variances in how the measure was calculated with differing approaches to IVR-answered calls or how to view Abandoned Calls. As a result, the integrity of the reported SQI is questionable.

The SDP's attempt to address this issue on the three "fronts" identified above should ultimately lead to improvements to all aspects of SQR. However, the simultaneous implementation of all the proposed changes at this time could be problematic because the foundation for data collection, tracking, analysis and reporting is shifting, resulting in potential confusion. For example, a definitional change to SQI metrics could invalidate the continued use of historical data collected to date for the setting of SQI targets going forward, i.e. using old data to set new targets is questionable given that the data would have been collected under different circumstances where utilities used their judgment to interpret the current SQI definitions and consequently there is inconsistency in the reported data, measured performance etc. Consequently, the proposed targets would not match the

expected performance that is being sought. In addition, using currently available historical data collected on the basis of previous SQI definitions to then set increased SQI targets for metrics based on revised definitions will create obvious gaps and confusion. Standards must be consistent with new definitions.

In as much as Hydro One supports the Board Staff's efforts, we suggest that the improvements be implemented in a controlled manner so that their effectiveness is not lost or potentially masked, due to the sheer number of changes underway. We believe that the scope or timing of this effort should be adjusted, enabling utilities to change in step with proposals to improve clarity (definitions), the need for greater scrutiny (more SQIs) and increased oversight (tighter targets). Perhaps a phased-in implementation of the proposals over a period could provide the necessary time to make the changeover. The process could start with phase I that would clearly define the SQI requirements, thus allowing utilities to collect, analyze and report performance in a consistent manner. Phase II would entail setting the revised SQI targets. Sufficient time would have to be allowed between Phase I and Phase II so that utilities may put in place the necessary processes to collect analyze and report performance. This will ensure that the reported performance will lead to appropriate SQI standards that reflect actual performance in a consistent manner. Hydro One notes that the Electricity Distributors Association is also advocating a phased approach for implementing new SQI standards[1].

Furthermore, Hydro One recommends a continued dialogue with the distribution industry through consultations that would allow parties to discuss in detail the progress in Phase I whereby progress on selected key issues and key milestones can be monitored and advice provided accordingly.

1.3. The need for change in SQR scope

In as much as there is a need to make improvements to the definitions of SQI metrics to ensure consistency in measurement, analysis and reporting, Hydro One is not aware of any global concerns raised by distribution customers that would require changes to the number of SQI metrics that need to be reported or the need to increase SQI standards. Is the Board's decision to introduce increased SQI measurement and raise the bar on minimum standards based on customer feedback which indicates broad dissatisfaction with services measured by the SQIs? If so then this information should be shared with the distributors. Hydro One is not aware of significant customer dissatisfaction issues in our current performance of the SQI services.

Service quality is driven by customers needs. This in turn means that service levels reflect the customers' willingness to pay for that level of service. Consequently any changes from the established levels that increase SQI metrics or increase minimum standards must reflect customers' dissatisfaction with the set standards and equally their willingness to pay more for the revised standards, data collection, analysis and reporting. The proposals put forward in the SDP will inevitably result in increased costs to utilities and consequently to the rates charged to customers. This result must be tested to ensure that it reflects what customers need and want.

[1] EDA's Comments on OEB staff discussion paper on Service Quality Regulation for Electricity Distributors, February 4, 2008

1.4. Application of SQR Proposal

The Board appears to have concluded that a split approach in the application of SQIs is warranted. This envisages the move to immediately mandate customer-related SQIs as standards enshrined in a code, whilst monitoring reliability-related SQIs for a further period before these, too, are codified.

Presumably the rationale for this approach is that the quality of measured data and reporting of reliability-related SQIs is not yet at a sufficient level for setting mandatory standards, and that further monitoring is therefore required. At the same time the Board's decision suggests that the quality of measured reported data for the customer-related SQIs is sufficiently accurate to allow these to be implemented as mandatory standards. Yet Board Staff recognize the need to redefine *all* SQIs, including the customer-related SQIs, because the current definitions are not sufficiently accurate and leave too much room for interpretation that leads to inconsistency in measurement and reporting. The distributors are in general agreement on the fact that the current set of data measured and reported under existing definitions is not consistent. Consequently this would suggest that the issue of consistent measurement and reporting is common to both the customer-related and reliability-related SQIs. If that is indeed the case, then more time should be allowed to sort out the issues for both sets of metrics. The key is to move forward ensuring that improvements being sought are reflected in a consistent set of metrics. Only then can the Board a consistent set of standards.

The proposals being put forward in the SPD will ultimately result in increased costs to utilities. Redefining the metrics may result in the need to review supporting processes for measurement and reporting and that may drive incremental investments to address that need. The introduction of new metrics or new targets will inevitably result in the need for new processes and potentially new facilities to deliver the new performance, and to measure analyze and report.

The potential for increased costs needs to be considered not only from the perspective of customers' willingness to pay for the new standards of service but also in terms of the utilities ability to recover those costs. The Board is moving forward with 3rd Generation Incentive Regulatory Mechanism ("3GIRM") for electricity distributors – a regime that will involve mechanistic adjustments to rates without the need for annual cost of service reviews. The use of mechanistic adjustments may drive outcomes that are in fact opposite to what the Board is proposing for SQR. For example, the use of a price cap formula that includes inflation and productivity is essentially directed at driving down costs so that utilities rates are in step with the desired trajectory set at the outset of the price control period. If now utilities have to implement new SQIs and stricter standards how will this be accommodated within the IRM? These issues are not independent of each other and need to be given due consideration.

1.5. Implications of SQR Proposal

The SDP proposes many changes to SQR, all of which have implications for distributors.

First and foremost is the issue of cost to implement the proposed changes. To date, the potential changes required by utilities' data collection, reporting and related processes have not been assessed. Is the data collected today sufficient to meet the desired changes and is there a need for incremental

changes which will result in increased costs? It would seem prudent that utilities first establish what can be done within the existing processes and what would be required incrementally to achieve the desired results. A cost-benefit analysis would help to establish the pros and cons (and the overall value) of the proposed changes. Hydro One believes such an analysis would be prudent before enshrining the changes in mandatory standards. This would help address the issue whether customers want performance to be changed and are willing to pay for that change. This is a trade-off that needs to be considered.

Another important consideration is the time to implement the proposed changes. Not only do utilities need to assess their processes for monitoring and reporting requirements but in addition they need to gain a better understanding of how increases in costs incurred translate into improvements in service quality. Time is required to analyze the measured data to assess the validity and consistency with SQR requirements. Most distributors are only now starting to grapple with cost analyses in defense of their cost of service submissions and rates submission under the OEB's 2007-2010 rate setting plans. A phased process, as suggested above, is more likely to allow progress to be made in a coordinated and orderly manner toward achieving the desired goals of consistent measurement and reporting of.

In summary moving forward with improvements to SQR requires the recognition of the following key process elements:

- Data availability
- Time to collect required data in a consistent manner
- Time to analyze data and test whether the resultant outcomes meet the desired goals
- Time to set up supporting processes that will result in sustainable and consistent monitoring and reporting,
- Time to implement new service delivery processes if required to meet new measures or increased targets, and
- Time to implement to allow utilities to test processes.

All of these must be taken into consideration when the Board considers setting the timetable for implementing SQR.

2. Specific Comments

Hydro One has focused its detailed comments on those SQI changes which are most impactive on Hydro One's business and service provided to customers.

2.1 Existing Customer Service Indicators

2.1.1 C1 – Connection of New Services

This measure represents an evolution in application and while some of the quantifications of service that is the "5 days" and "94%" may require further analysis Hydro One agrees that the measure is appropriate.

2.1.2 C2 – Underground Cable Locate

Hydro One believes that the proposed change in definition is appropriate. However, we suggest that the definition could be rewritten to provide clearer meaning as this is only an appointment if the customer requests to be present, the way it is presently written says that "locates" will be abandoned and "locates" and "appointments" will be merged together. Hydro One proposes the following as change:

"Board staff proposes that the Board abandon the "Underground Cable Locate" indicator as a stand-alone measure and that requests for cable locates where the customer has requested to be present for the locate be addressed as part of the "Appointments Met" and "Appointment Scheduling" measures."

2.1.3 C3 – Appointments Met

Hydro One appreciates the proposed revision does focus on improvements to tracking customer appointments and may lead to greater customer satisfaction.

The revised metric focuses on a utility meeting the original appointment time, however does not allow for the customer re-scheduling the appointment. However:

- The current utility practice is to reschedule appointments that cannot be kept (assuming this occurs before they are missed). This practice seems to be excluded from the definition.
- The revised service level of 95% is substantially higher and is calculated in a more demanding fashion against the original appointment time (no reschedules).
- Reschedules initiated by the customer are an oversight; they should be treated as the original appointment time not as a reschedule.

The proposed definition and target changes will however have an impact on costs as changes to system that support these requirements needs to be assessed. Hydro One's initial assessment is that the cost of these changes could be substantial.

For example Hydro One does not track the following quantities in its current Customer Information Systems, all of which would be required to meet the proposed changes:

- Tracking whether the appointment time was re-scheduled (it can be changed
- Tracking whether the re-scheduling was a result of a customer request or a Hydro One missed appointment.
- The Tracking whether a call to re-schedule occurred within 2 hours of missing an appointment.

2.1.4 C4 – Telephone Accessibility

Beginning in 2005, Hydro One increased performance in this area to > 70% calls answered in 30 seconds, as an initiative to improve our service to customers. Despite this improvement, our

performance is more than 10% below the annual sector performance of 87% over the period 2004 – 2006 as reported in the SDP.

The SDP considers a change in definition as well as an increase in target, and both steps will improve call answer service to customers. A call service performance of 65% of calls answered in 30 seconds which includes IVR calls will provide less than 65%/30 performance from live call representatives. Given that the change to definition will improve call performance, Hydro One questions the need for an immediate second step of increased service performance, by increasing the target to 75% of live representative calls answered in 30 seconds.

Hydro One monitors customer satisfaction with our call response, and on a monthly basis we undertake follow up transactional surveying with customers who have recently called our call centre. In 2007, results tracked at about 80% of customers satisfied with their ability to access us. Accessibility dissatisfaction appears primarily during outage and storm activity, where large call volumes make it difficult for some customers to get through to Hydro One. Therefore, Hydro One is looking at options to improve call access and response during power outages, and was not considering investing in increasing the call answer service performance to 75% / 30 seconds.

Increasing our call answer performance to 75%/30 seconds we estimate could cost between $1.0 and $1.3 million annually. Given customers are generally satisfied with the existing call access for most types of enquiries, we do not believe there is a customer benefit for this investment.

We agree with the SQI Consulting Group's comment that call volumes are volatile and often increase dramatically and suddenly as a result of external conditions outside the utility's control. At Hydro One, an extensive storm can drive up to 100,000 calls to our call centre in one day. Any application of this measure should allow for this volatility and the potential that the target may be missed periodically in extreme situations.

2.1.5 C.5 – Written Responses to Enquiries

The change to the definition of this measure will expand the volume of activities included in this metric, to add written response to faxes and customer email.

The SQI Consultation Sub Group concluded that the original definition of this measure was largely acceptable, with some limited revisions. The SDP changes the definition from "enquiries relating to the customer account", to "enquiries relating to a customer's existing or prospective service." In our view these are very different definitions, where the current definition is relating primarily to the customer billing and information on their account, and the proposed new definition could be viewed with a broad interpretation of "service" to include power delivery, outage response, call response, and so forth. Further clarification to this definition is required.

2.2 Proposed New Customer Service Requirements

2.2.1 D1 – Rescheduling of Missed Appointments

Hydro One recognizes that this measure supports the appointment measure without moving to fines etc. It encourages better communication with our customers and drives utility behaviour to meet with customers when they promise. However, as per discussion on proposed changes to SQI C3 above, assessment of the information systems capability is required as tracking call back within 2 hours of a missed appointment is believed not a current system capability. Consequently the cost of implementing this change may be significant.

2.2.2 D2 – Appointment Scheduling

Hydro One believes that scheduling appointments within 5 days of service conditions being met may be possible. However existing business processes will need to be assessed to determine what changes are required and what would be the associated cost.

2.2.3 D3 – Telephone Call Abandon Rates

The discussion paper recommends a new metric of Call Abandon, and a target of 10% Abandon rate or less, on a yearly basis. Hydro One agrees that the Abandon rate is another measure of call centre service to customers, and we are able to track and report on our Abandon rates.

We agree with the SQI Consultation Sub Group's comment that call volumes are volatile and often increase dramatically and suddenly as a result of external conditions outside the utility's control. At Hydro One, an extensive storm can drive over 100,000 calls to our call centre in one day, and in these instances our abandon rates can be as high as 12%. Any application of the measure should allow for this volatility and the potential that the target may be missed periodically due to extreme situations.

2.3 Existing System Reliability Indicators

2.3.1 E1 – Setting Standards for System Reliability

Hydro One agrees that until the definitions and data gathering are refined the move to mandatory standards for reliability should be delayed. However, establishing clear definitions is a priority activity. At the same time Hydro One suggests that the Board should contemplate moving to establishing reliability SQIs for both urban and rural customers. This would mean taking line length into consideration when establishing a level of reliability to the customers.

2.3.2 E2 – SAIDI, SAIFI and CAIDI Definitions

Hydro One suggests that the CAIDI metric be removed from consideration as a primary SQI metric and instead be used as a secondary indicator. CAIDI is the ratio determined by dividing SAIDI by SAIFI and as such is not a direct measure of reliability. Consequently unmatched improvements in SAIDI and SAIFI may lead to misleading interpretations through the use of CAIDI.

2.3.3 E.3 - Adjusting Reliability Measures for "Loss of Supply"

Hydro One agrees with the need to continue to report SAIDI, SAIFI and CAIDI inclusive and exclusive of loss of supply. Also, consideration should be given to expand for inclusive and exclusive reporting of uncontrollable events, which are impactive on the operations of a utility. Furthermore, "loss of supply" should measure and report any loss of supply to LDCs whether it occurs from the bulk transmission system or through the distribution system, e.g. as for distribution embedded LDCs.

2.4 Proposed New System Reliability Measures

2.4.1 F.1 – Worst Performing Circuits

Hydro One believes that introducing a metric that measures worst performing circuits is a useful addition to the reliability SQI category. Relying solely on the measuring and reporting an average SAIDI and SAIFI may obscure the fact that some customers are receiving excellent reliability while other customers are receiving poor reliability service but both sets of customers paying the same distribution rate. However, if this metric were to be adopted it should be monitored for a period of time sufficiently long such that sufficient practical experience is gained in definitions, data collection and quality, analysis, and reporting to ensure consistency in understanding and reporting. Regarding what elements should be measured (for example, the 5 worst circuits, the worst 3% of circuits, or some other quantities) sample data from representative distributors could provide a statistical base e.g. a Bell curve distribution, for establishing a standard for reporting. Also, the term "worst" could be defined by using the reliability frequency (SAIFI) and duration (SAIDI) of interruptions as impacts of interruptions vary depending on customer circumstances. For example, frequency of interruptions has a greater impact on customers with manufacturing processes whereas duration of interruptions has a greater impact on residential customers. Any setting of a performance standard will require rigorous analysis of data quality.

2.4.2 F.2 – System restoration

This measure could be a replacement for CAIDI as a more effective reliability ESQI. Restoration time is of prime importance to electricity consumers and as such having a stand alone metric to measure such performance would be helpful in assessing quality of customer service in that respect. However, like all new measures it needs to be tested for consistency of reporting and data accuracy. Therefore we suggest that if this metric is introduced that it be monitored initially for a pre-requisite period during which understanding, data collection and reporting consistency is established before moving to mandatory standards. The measure of system restoration should be directly related to the impact caused to the customer, e.g. how long is the power interrupted?

2.4.3 F.3 – Effect of System Interruptions on Other Distributors

Hydro One is of the view that there is no need to develop a new reliability SQI that measures the "Effect of System Interruptions on Other Distributors". The Distribution System Code currently requires each LDC to monitor the effect that a "loss of supply" from an outside source has on its own

system reliability. Therefore embedded distributors must monitor and report the effect that "loss of supply" from a host distributor has on its own system reliability. Consequently it is not clear what advantages would accrue by imposing this SQI and having a host distributor that causes a "loss of supply" to an embedded distributor tracks the number of times that it is causing an outage or the number of distributors that are affected. As noted in Hydro One commentary on SQI E3 – Adjusting Reliability Measures for "Loss of Supply" – if the reporting on that SQI is enhanced to include all sources of "loss of supply" whether from transmission or distribution related incidents, there would be no need for introducing this new metric.

2.4.4 Momentary Average Interruption Frequency Index (MAIFI)

Hydro One suggests that it would be more productive to improve the SAIDI and SAIFI metrics to include both urban and rural measurements of performance instead of developing this Frequency Index (MAIFI). Research on MAIFI experience indicates that while it has the potential to be a useful measure, there appears to be significant variability in data gathering and reporting. For example, as the reporting improves it appears that more outages are occurring while it is the ability to capture the data that is improving. The costs incurred to track MAIFI performance depends on the degree of data required, but nevertheless operating systems would have to be more automated at a very significant cost. These implementation costs, which would have to be approved by the regulator appear to be exponential to degree of detail required. In a manually operated distribution system that makes up most of the Hydro One distribution system collecting the counter reading from a recloser does not give an adequate representation of the number of momentary interruptions. For example if the number of interruptions reported was 3, could one infer that it was 3 momentary interruptions or 2 momentary interruptions and one sustained interruption that was implied? There is no way of tracking the information with current systems to know what actually happened.

3. Responses to Board Staff Questions

3.1 Customer Service Index C4

Should the Telephone Accessibility ESQR apply only to those calls that are directed to a "customer care telephone number" or should it be expanded to apply to calls to other telephone numbers (such as telephone numbers identified as being for the purpose of inquiries relating to administrative or general matters)? Why or why not?

Hydro One does not recommend applying the Telephone Accessibility ESQR to other general telephone numbers. This measure is typical of a call centre environment, and it is due to this environment that the measure can be implemented. The call centre environment has installed the Computer Telephony-Integration (CTI) equipment and software required to accept, route and track calls to staff who are always at their desk and ready to answer calls and who work in a very strict scheduling environment. (For example, our call representatives cannot take a break from their desk unless it is scheduled when other people are able to replace them to respond to calls.) General enquiries can be about a variety of topics and are distributed to a range of contacts across the company; the tracking systems are not established to route and monitor answer time per call, nor

would it be prudent to schedule these experts to always be at their desks, restricting the time available for meetings, discussions, planning, and other normal work activities.

3.2 Customer Service Index C5

Should the Written Response to Enquiries ESQR apply only to those enquiries that relate to the customer's existing or prospective service, or should it be expanded to apply to enquiries that relate to administrative or general matters? Why or why not?

The ESQR should not be expanded to apply to enquiries that relate to administrative or general matters, primarily due to the organization of such activity within the Utility. Written response to the customer enquiries are generally coordinated within the customer care and call centre organization, supported by established tracking systems and staff "back office" scheduling processes that are able to maximize productivity and meet, track and report on turn-around time. These systems and scheduling opportunity are not established across the Company and would not be a prudent investment given the smaller numbers of administrative or general topics.

4. In Summary

Hydro One appreciates and supports wholeheartedly the effort that the Board is marshalling to move forward with the development of service quality regulation. This effort promises more efficient regulation for the electricity distributors in the province that should benefit the utilities, their customers and the regulator. In this respect Hydro One recommends an orderly process that allows sufficient time for utilities to adjust to the new definitions, new SQI metrics and higher standards so that monitoring and reporting of SQIs is done in a consistent manner. This in turn must reflect the need for appropriate standards that in turn reflect customer needs and wants.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10 List 1

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 2

Preamble: The PA Summary Conclusion is that
The study has produced some useful results for the company. In particular, the results provide an accurate portrayal of the performance of the company, while at the same time demonstrating the importance of measuring and reporting performance in an appropriate manner to fit the individual situation for each utility. Hydro One's service territory has some unique characteristics, most notably its low density, and the performance of the company appears different depending on whether or not those characteristics are taken into account in measuring performance. Overall performance of the company rates as "good to very good" when performance is normalized by the volume of assets (e.g. km of line). However, when measures that are normalized by customer base (e.g. spending or customer hours per customer served) are used, Hydro One performance appears to be less efficient. The low density/rural nature of the Hydro One system leads to this, since customer-normalized metrics tend to favor higher density systems.

Questions:

a) Provide in tabular form the following performance metrics for the Period 2004-2007 and Forecast 2008
   i. Assets $ per km of line; per customer; per GWh distributed
   ii. Capital $ per km of line; per customer; per GWh distributed
   iii. O&M $ per km of line; per customer; per GWh distributed

b) Compare and discuss the trends in the metrics.

c) Compare HO 2004-2006 3 year averages to the PA peer group in terms of Rank and discuss why HO ranks where it does.

d) What steps is HO taking to improve its performance?

e) With regard to Tree trimming what factors are contributing to HO's rank and what is HO doing to improve this?

Response

a) The requested metrics, using the PA study definitions for the various metric components, are provided in the table below. Data from 2004-2006 came from the study as submitted during 2007. The values for 2007 are based on actual

results and the 2008 are based on budget. We have provided the values for the sum of distribution lines and substations, to cover the entire distribution business.

	ACTUAL				BUDGET
	2004	2005	2006	2007	2008
Assets $ per km of line	46,655.37	48,774.74	51,748.68	52,330.92	57,280.63
Assets $ per customer	4,124.14	4,274.60	4,497.57	4,542.57	4,942.16
Assets $ per GWH distributed	119,249.85	123,227.32	133,897.73	131,043.76	143,108.62
Capital $ per km of line	1,819.97	1,956.16	2,534.05	2,436.04	2,542.77
Capital $ per customer	160.88	171.45	220.24	211.27	218.09
Capital $ per GWH distributed	4,651.78	4,942.47	6,556.77	6,094.88	6,315.30
O&M $ per km of line	1,477.58	1,518.73	1,814.91	2,003.71	2,153.10
O&M $ per customer	130.61	133.11	157.74	173.78	185.81
O&M$ per GWH distributed	3,776.67	3,837.24	4,696.01	5,013.21	5,380.41

b) Asset $ per customer, per km of line and per GWH have increased on average 4% per year for the period 2004 to 2007. The 2008 over 2007 increases for the various measures are largely due to the increasing asset base for 2008.

Capital spending increased each year from 2004 to 2006. In 2007, there was a decrease in capital expenditures from 2006 levels, which is reflected in the capital $ per line, per customer and per GWH metrics. On an investment per asset basis, Hydro One is still low in comparison to the other utilities in the panel.

O&M spending increased in the 2004 – 2007 period, and the budget reflects an increase for 2008. The increases in O&M are largely due to increases in storm-related costs, line maintenance costs, forestry costs, and line patrol and data collection costs .

c) The response below is based on the values for lines and substations together.

In the area of capital spending, Hydro One ranked 3rd lowest of 10 companies in spending per km of line, lowest of 11 in capital per asset, 3 of 6 in capital spending per GWH transported, and 9 of 11 in capital per customer.

In O&M, Hydro One ranked 4 of 10 in O&M per km of line, 6 of 11 in O&M per asset, 5 of 6 in O&M per GWh transported, and 10 of 11 in O&M per customer.

These figures are reflective of Hydro One Distribution's service territory and electric system, as well as its spending patterns. In the figures which are normalized by assets (gross book value or km), Hydro One's spending is on the low side of the panel. In the figures normalized by customers, Hydro One spending results are on the high side. This reflects the very rural nature of the Hydro One service territory, and the fact that a lot of assets and kilometers of line are necessary to serve each customer. That translates to a relatively high investment per customer, both in terms of capital and O&M. The low spending on a per-asset basis provides a better indication of the effectiveness of the management approach at Hydro One in terms of minimizing spending to the extent possible given distribution system required to serve a largely rural customer base.

d) Hydro One has analyzed reliability performance as shown in Exhibit A, Tab 3, Schedule 1, pages 18 and 19. Based on the results, which indicate that the greatest contributor to unreliability is "Tree Contacts", Hydro One plans to enhance its Vegetation Management Program. Enhancements will focus on reducing the maintenance cycle to 8 years, which is expected to result in reliability improvements as detailed in the interrogatory response at Exhibit H, Tab 1, Schedule 49.

In addition to enhancing the Vegetation Management Program, Hydro One is undertaking initiatives in both the sustaining and development capital areas to improve reliability as discussed in the interrogatory response at Exhibit H, Tab 1, Schedule 52, part c .

e) Hydro One's rank based on tree trimming measures is heavily influenced by the vegetation maintenance cycle. As shown on page C-41 of Exhibit A, Tab 15, Schedule 2, Hydro One's 2006 clearing cycle is in the fourth quartile and longer than other utilities. The longer cycle results in more vegetation growth and increased numbers of hazard trees on and adjacent to rights of way. These characteristics require greater effort to maintain and increase expenditures. Hydro One has recognized the impact of a long maintenance cycle on long-term vegetation management costs and has taken action to implement a shorter tree clearing cycle. As well, recognizing that vegetation management presents one of the greatest long term risks, if not the greatest, for the company, Hydro One has studied the area of vegetation in detail and has retained experts in this field to provide advice on the most prudent course of action. Refer to Exhibit H, Tab 1, Schedule 49, and the report entitled "2008 Vegetation Management Program Review" attached to Exhibit H, Tab 1, Schedule 14. In addition Hydro One has and continues to investigate areas of improvement as demonstrated in Exhibit H, Tab 1, Schedule 15.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #11 List 1

Interrogatory

Reference: Exhibit A, Tab 15, Schedule 3, page 10, Table 3

Preamble: *The Board does accept the submissions of intervenors regarding the expected benefits of the $4.75 million expenditure and directs Hydro One to include in its next main rates case filing a budget and a work plan to implement all the cost-effective line-loss reduction suggestions contained within the Kinetrics study. If Hydro One concludes that any of the recommendations in the Kinetrics study should not be implemented, it must clearly demonstrate the reasons for that position, and an accompanying budget and work plan for its preferred implementation plan.(4.3.10)*

Question:

a) What DLFs/TLFs are to be included in 2008 rates for each of the customer groups- the values in column 1 of Table 3 or the values arising from the Kinetrics Study- column 2?

b) Where is the Comprehensive Work Plan and Budget for Loss Reduction?

c) Provide a summary Table showing historic and forecast 2008 expenditures and describe how the 2008 plan relates to the new Kinetrics Study recommendations.

Response

a) The proposed loss factors are shown on the Table of loss factors in Exhibit G1, Tab 10, Schedule 1, page 3 and are described in the same Exhibit.

b) Please see interrogatory response at Exhibit H, Tab 1 Schedule 97 and Exhibit H, Tab 3, Schedule 2.

c) Please see interrogatory response at Exhibit H, Tab 1 Schedule 97 and Exhibit H, Tab 3, Schedule 2.

Table 1: Hydro One Distribution Network Loss Reduction Program

Year	Spending ($M)
2006	1.1
2007	5.6
2008 Projection	1.3
Total (YE 2007)	8.0

The Distribution Network Loss Reduction Program, scheduled to be completed in 2008, implements the Kinectrics update study recommendations. The program is fully funded through an approved Conservation and Demand Management initiative, and as such no costs are included in the 2008 revenue requirement in this Application.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #12 List 1

Interrogatory

References: Exhibit B1, Tab 1, Schedule 1, Section 2.0;
Exhibit B1, Tab 2, Schedule 1, pages 4/5

Questions:

a) Provide Hydro One Networks' rationale for proposing a 60% debt/40% equity structure for 2008 rates rather than a transitional debt/equity structure.

b) Please provide a revised Capital Structure/Cost of Capital the deemed capital structure approved by the Board for 2008 Networks' transmission rates.

c) Please provide the actual Coupon (effective debt cost) for the 5 and 10 year debt issued in the latter part of 2007 and the amount mapped to Dx. Compare this to the forecast.

d) For debt to be issued in 2008 has HO updated the forecast effective coupon rate and/or the amounts to reflect latest bond rate forecasts? If not when will this be done?

Response

a. See response in Exhibit H, Tab 1, Schedule 111 part a.

b. Hydro One Transmission's approved deemed capital structure for 2007/08 was the same as that being proposed for Hydro One Distribution for 2008 (ie. 60% debt and 40% equity).

c. In October of 2007, Hydro One issued $300 million of 10 year notes with a 5.18% coupon rate, of which $75 million was mapped to Hydro One Distribution. This compares to the forecast of $102.5 million of 10 year notes with a 4.71% coupon rate and $102.5 million of 5.5 year notes with a 4.47% coupon rate (as shown on lines 33 and 34 of page 4, Exhibit B2, Tab 1, Schedule 2).

d. Hydro One has not updated forecast debt rates or amounts for 2008. See response in Exhibit H, Tab 12, Schedule 3 part a.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #13 List 1

Interrogatory

Reference: Exhibit B2, Tab 1, Schedule 2, pages 4 – 5

Question:

a) For the debt that matured in 2007 (lines 1-9 page 4 the Schedule) in an amount of $ 237.2 million, provide a calculation of the impact on overall 2007 (and 2008) carrying cost and embedded debt cost due to replacement with lower denominated debt.

b) For the debt to be issued in 2008 (lines 24-26 page 5 the Schedule) in an amount of $434.1 million please calculate the impact of a change in the effective rate of 10 basis points on the 2008 carrying costs.

c) Please explain the increase in carrying costs and effective embedded debt rate between 2007 and 2008.

Response

a) The impact of refinancing maturing debt in 2007 with lower coupon debt issued in 2007 (lines 31, 33 & 34 page 4 the Schedule) is approximately $2.2 million lower carrying costs or about 10 basis points lower embedded debt rate in 2007, and approximately $4.0 million lower carrying costs or about 17 basis points lower embedded debt rate in 2008. This impact has been included in calculations of the embedded debt rates on pages 4 and 5 of Exhibit B2, Tab 1, Schedule 2.

b) For the debt to be issued in 2008 in the amount of $434.1 million an increase in the effective rate of 10 basis points would increase 2008 carrying costs by $0.2 million.

c) The increase in carrying costs is due to an increase in the average debt outstanding from $2,131.1 million in 2007 to $2,325.8 million in 2008. The embedded cost of debt rate, however, declines from 5.84% in 2007 to 5.71% in 2008.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #14 List 1

Interrogatory

Reference: Exhibit B1, Tab 1, Schedule 1, page 3

Question:

a) Which of the following 2008 forecast debt amounts and rates will be updated prior to hearing and prior to issuance of the Board's Rate Order
   i. Embedded Debt
   ii. Third Party Long Term Debt
   iii. Short Term Debt

b) Since the January 2008 OEB Forecast is now available, please provide an updated version of the Table at B1T1S1 Page 3 Section 7

Response

a. Hydro One is not planning on updating its 2008 Distribution rate filing for revised forecast debt rates or amounts. See response to Exhibit H, Tab 12, Schedule 3 part "a".

b. An update to the table in Exhibit B1, Tab 1, Schedule 1 page 3 is provided below based on the OEB forecast:

2008 Cost of Capital

Particulars	$ Millions	%	Cost Rate (%)	Return ($M)
Third Party long-term debt	2,326	53.1	5.71	133
Deemed long-term debt	128	2.9	6.10	8
Deemed short-term debt	175	4.0	4.47	8
Common equity	1,753	40.0	8.57	150
Total	4,382	100.0	6.82	299

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #15 List 1

Interrogatory

Reference: Exhibit C1 Tab 2 Schedule 2 Page 3- lines 15-25 and Tables 1, 2 and 3

Preamble: *The change in overall (Sustaining OM&A) spending for 2008 relative to historic expenditures is attributed to the following reasons:*
• Increased vegetation management line clearing and brush control to manage and improve reliability.
• Increased maintenance on distribution station transformers to restore the condition of these aging assets.
• Maintenance and other OM&A spending for Smart Meters.
• Continuing efforts on lines data collection and increased emphasis in defect corrections to manage reliability and safety.

Questions:

a) Discuss why the Demand (and budget) for Stations Maintenance is lower in 2008 than 2006-2007? Provide Activity levels for all three years.

b) Provide 2007 Line management trouble call volume and actual spending and discuss why the Line Management Trouble forecast of 49,100 is lower/higher than 2007.

Response

a. There was an increase in 2006 and 2007 Demand and Corrective spending to address identified site, safety and security issues that were, to a large part, initiated by the increase in copper theft at distribution stations. Hydro One increased the number of site inspections and repairs to address these concerns. In addition, as a result of additional diagnostics introduced during 2005 and 2006 a greater number of equipment issues were identified that required immediate attention under the Demand program, thereby requiring a higher level of spending during the 2006 and 2007 period. The best indicator of demand activity is that the security inspections and repairs will not be required to the same extent during 2008 as occurred during 2006 and 2007, and emergency equipment repairs are not projected to be as great as occurred during the previous two years.

b. Please refer to interrogatory response in Exhibit H, Tab 13, Schedule 3, parts a and b. There is no material variance between the 2008 forecast and the 2007 actual result.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #16 List 1

Interrogatory

References: Exhibit C1 Tab 2 Schedule 2 Pages 29-34 and Table 9
Exhibit C1 Tab 2 Schedule 2 Page 35 and Table 10
Exhibit D1, Tab 2, Schedule 1

Questions:

a) Provide the Business Plan for the Vegetation Management Program that supports the increase in Accomplishment and Budgets from 2006-2008.

b) What Arborist input was provided in preparing the Plan. If not covered in the Plan please describe?

c) Please update Table 10 on page 35 with 2007 actuals and 2008 forecast.

d) Provide either the latest ACA report for Vegetation Management or a summary of current conditions and remedial plans and budgets.

e) Discuss why HO Tree trimming cost per tree and per km of ROW are the highest/second highest of the Comparator group in the PA study [Exhibit A-15-2 Attachment A, Appendix C-39 and C-40.]

Response

a. Hydro One does not prepare a detailed business plan on an individual program basis. Additional support for the 2008 Vegetation Management Program is also provided in the interrogatory response at Exhibit H, Tab 1, Schedule 49.

b. Hydro One incorporates a number of analyses, studies, and professional/expert opinions into its business plan. Arborists or forestry professionals that worked on, influenced, or reviewed the 2008 plan include:

- R.T. Griffiths – Author of the Griffiths Vegetation Management Study that was referenced at Hydro One's EB-2005-0378 rate filing and that was used as a basis for the 2008 program. Mr. Griffiths is a Registered Professional Forester (R.P.F.) with over 20 years in utility forestry operations.

- John Hawkins – The Senior Network Management Officer at Hydro One responsible for planning the Vegetation Management Program. Mr.

Hawkins has a Bachelor of Science in Forestry (BScF) and 35 years experience with utility forestry operations and vegetation management. He is also a registered member of the International Society of Arborists (ISA), Utility Arborists Association (UAA), and the Ontario Vegetation Management Association (OVMA).

- Stephen Cieslewicz – A Utility Arborist who has over 20 years experience in utility vegetation management. He is the President and Chief Operating officer of CN Utility Consulting Inc., vegetation management consulting firm. Mr. Cieslewicz reviewed Hydro One's plan.

- A number of other forestry and utility vegetation management professionals within Hydro One have contributed to the plan including Program Development Officers, Forestry Schedulers, and field staff.

c. Please see addition to table below. Hydro One does not forecast reliability measures broken out by cause contribution and as a result 2008 has not been included in the table.

Year	All Interruptions (hrs)			Force Majeure Events (hrs)		
	Total	Tree Contribution	Tree %	Total	Tree Contribution	Tree %
2007	11.4	3.9	34%	2.8	1.3	46%

d. The summary of current vegetation conditions is provided in Exhibit D1, Tab 2, Schedule 1, page 16. The remedial plan along with associated budgets is discussed in Exhibit C1, Tab 2, Schedule 2 beginning on page 29. The plan is centred on increasing vegetation management accomplishments to reduce maintenance cycles and improve the condition of Hydro One's rights of way.

e. The primary driver for Hydro One's high cost per tree and per km is the long clearing cycle length in comparison to other utilities as shown in Exhibit A, Tab 15, Schedule 2, Attachment A, Appendix C41. The long cycle results in greater amounts of vegetation that need to be removed on a per tree or per km basis than would be the case if the cycle was shorter and vegetation did not have the time to grow as much. In addition, as vegetation comes closer to energized conductors, the procedures to remove tree growth become more time consuming and costly.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #17 List 1

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 5, page 9 and Table 2

Questions:

a) Provide reasons why meter reading costs are lower in 2008 compared to 2006 while metering OM&A is significantly higher.

b) Compare the 2008 meter reading Unit costs (per customer) to those identified in the PA Benchmarking Study [Exhibit A-15-2 Attachment A] and indicate the main components of costs included in the $13.97 per customer/yr cost in Appendix C page C-35.

Response

a. The meter reading costs were expected to decline in 2008 due to a reduction in the number of manual meter reads relating to the Smart Meter Project. The primary reason for the increase in metering OM&A costs is the maintenance of additional equipment and systems related to the Smart Meter program.

b. The meter reading unit cost per customer in 2008 is forecasted to be $12.50.

The $13.97 per customer cost (in Appendix C page C-35 of the PA Benchmarking Study) contains two major cost components:

Labour costs 87%
Transportation costs 12%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #18 List 1

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 6, page 6 and Table 3

Questions:

a) Provide the 2006 and 2008 Service Schedules/Descriptions corresponding to the CCF&S services costs shown in Table 3.

b) For each category highlight the increase in service levels and costs adding to the total $10 million (13.5%) increase in CCF&S costs 2006-2008

Response

a) For Service Schedules/Descriptions corresponding to the CCF&S services as shown in Table 3, please refer to the following as contained in the Rudden Study:

Detailed Description of Common Corporate Functions and Services	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Board of Directors (Corporate Management)	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
Chair (Corporate Management)	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
President and CEO (Corporate Management)	The CEO's primary accountability is leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. The CEO develops and updates Hydro One's strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.
CFO's Office (Corporate Management)	The CFO provides Hydro One and its subsidiaries with strategic review and approval with respect to all financial and investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting are also provided by the CFO to Hydro One Inc. and its subsidiaries as required.

Detailed Description of Common Corporate Functions and Services	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Corporate Controller (Finance)	Revenue Management; Financial Modeling & Analysis; Corporate Planning & Reporting, Support & Accounting Policy; Corporate Accounting Policies & Systems; Regulatory Finance; Inergi Finance; Financial Strategy
Treasury (Finance)	• Risk management including insurance purchasing • Insurance claims settlement • Financial risk management-foreign exchange, interest, credit • Cash & banking operations-cash forecasting, strategy & banking relationships, bank account management • Debt management-prospectus, debt issuance, borrowing, maintain relationship with shareholders • Funds management-deployment of short term funds and manage longer term funds Investor Relations is responsible for: Relationship with shareholders, creditors, equity analysts & rating agencies
Taxation (Finance)	Meet internal and external tax compliance requirements and reduce the overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, GST, PST, and DRC returns for all entities), tax accounting, lobbying for legislative tax changes, and government tax audits.
Financial Strategy (Finance)	Provides financial support services, including business case review and preparation, project management, decision support, business valuation, transaction support, deal structuring, and business consulting services.
Human Resources	Focused primarily on Employee and Labour Relations.
Labour Relations (Human Resources)	Provides full-scale service pertaining to bargaining, Ontario Labour Relations Board hearings, grievance and arbitration hearings, advice and guidance, plus training to all levels of Hydro One management. This involves interaction with 21 different unions and 24 collective agreements.
Corporate Services- SVP (Human Resources)	Oversight of Corporate Services departments

Detailed Description of Common Corporate Functions and Services	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Corporate Communications	Supports all communications initiatives, both external and internal. Interacts with most other Hydro One departments but has a special focus on working with Customer Service department.
Law (General Counsel & Secretariat)	Provides legal advice to all business units, acting as an internal "law firm" for the Corporation on most aspects of law affecting it, and is also well acquainted with day- to-day requirements of the Corporation.
Corporate (General Counsel & Secretariat)	Oversee and support Law, Regulatory and Corporate Secretariat General Counsel functions.
Corporate Secretariat (General Counsel & Secretariat)	Provides direction and analysis in areas of: 1) Board and Committee(s); 2) Support to the Office of the Chair and members of the Board of Directors; 3) Code of Business Conduct; 4) Community Citizenship; 5) Freedom of Information and Privacy, 6) Corporate Archives, 7) Corporate Records, and 8) Corporate Secretariat Support.
Regulatory Affairs	Coordinate filings with OEB; Manage relationship with OEB; Cost Allocation and Rate Design for regulated Tx and Dx, in particular, rate structures and rates for Tx and Dx Tariffs; Assist implementation of approved Tx and Dx rates; Support transmitters' representative on IESO Technical Panel; Provide load forecasts for all business units of Hydro One and for IESO; Manage MV Star to support wholesale and retail settlement; Provided strategic and analytical support to load research and CDM initiatives.
Regulatory Affairs- OEB Cost (Regulatory Affairs)	OEB costs for Tx and Dx activities.
Corporate Security	Provides security services including initiatives to address new security threats, investigations into Code of Business Conduct violations and criminal acts, conducting threat and risk assessments, background clearances, emergency response, and revenue-protection – theft of power investigation.

Detailed Description of Common Corporate Functions and Services	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Internal Audit & Risk Management (Internal Audit)	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.

b) The following are the service levels and associated increases in costs for the period 2006 through 2008:

i) Finance: +$4.6M associated with increased work requirements related to Bill 198 and new internal control and regulatory requirements, and transition to international accounting (IFRS) standards.

ii) Human Resources: +$2.1M associated with higher purchased contract services for HR and higher costs for increased HR-related transactional work.

iii) General Counsel & Secretariat: +$0.7M Higher external legal costs due to work related to general civil litigation, regulatory rate filings, Bruce x Milton transmission expansion, and labour contract negotiations

iv) Regulatory Affairs: +$3.9M Higher OEB fees and higher labour associated with increased regulatory compliance requirements.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #19 List 1

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 6, page 37 and Table 13

Question:

a) For each Category in Table 13 Provide a description of the Increased Service levels and costs adding to the total increase of $14 million (15%) in Asset Management costs 2006-2008.

Response

a) As there is a slight decrease between 2006 and 2007, the increase shown in Table 13 is primarily between 2007 and 2008. Please see the response to Exhibit H, Tab 1, Schedule 85 for a description of the underlying reasons for that increase.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #20 List 1

Interrogatory

Reference: Exhibit C1 Tab 3 Schedule 1
Exhibit C1 Tab 3 Schedule 2

Questions:

a) Provide the number of employees for each year 2004-2008 reflected in the Annual Networks Payroll table.

b) Provide similar tables to that attached below showing Compensation for each major employee group (e.g., Society Staff, PWU Staff, Management Staff, etc.). In each case, please also provide the number of staff in each category by year.

Number of Employees - Full-Time Equivalents (FTEs)	2002	2003	2004	2005	2006
Executives	8	6	5	5	5
Managerial	29	32	22	24	24
Management/Non-Union	247	240	145	160	168
Unionized	1,258	1,235	1,079	1,130	1,158

Compensation - Average Yearly Base Wage	2002	2003	2004	2005	2006
Executives	$ 159,543	$ 137,812	$ 163,696	$ 173,545	$ 178,347
Managerial	$ 106,243	$ 74,940	$ 104,604	$ 113,378	$ 116,860
Management/Non-Union	$ 73,045	$ 47,168	$ 71,798	$ 92,539	$ 94,271
Unionized	$ 59,558	$ 53,981	$ 62,159	$ 63,724	$ 65,747

Compensation - Average Yearly Overtime	2002	2003	2004	2005	2006
Executives	$ -	$ -	$ -	$ -	$ -
Managerial	$ 119	$ -	$ -	$ -	$ -
Management/Non-Union	$ 6,465	$ 2,731	$ 3,802	$ -	$ -
Unionized	$ 4,645	$ 4,538	$ 4,825	$ 6,085	$ 6,368

Compensation - Average Yearly Incentive	2002	2003	2004	2005	2006
Executives	$ 40,263	$ 51,393	$ 51,399	$ 59,590	$ 62,632
Managerial	$ 7,649	$ 8,050	$ 13,318	$ 14,608	$ 15,321
Management/Non-Union	$ 3,560	$ 2,294	$ 3,889	$ 4,173	$ 5,000
Unionized	$ 81	$ 61	$ 76	$ -	$ -

Compensation - Average Yearly Benefits	2002	2003	2004	2005	2006
Executives	$ 49,157	$ 157,059	$ 110,220	$ 71,938	$ 75,287
Managerial	$ 25,722	$ 23,403	$ 38,797	$ 39,373	$ 40,810
Management/Non-Union	$ 21,568	$ 19,449	$ 27,502	$ 33,805	$ 31,693
Unionized	$ 16,005	$ 18,435	$ 23,096	$ 22,679	$ 23,185

Total Compensation - Year over Year Percentage Increases - Interrogatory 25 (c)

Executives	Total Compensation	Percent Increase
2002	$ 1,991,705	
2003	$ 2,077,382	4.3%
2004	$ 1,626,575	-21.7%
2005	$ 1,525,360	-6.2%
2006	$ 1,581,330	3.7%
Managerial		
2002	$ 4,052,251	
2003	$ 3,404,583	-16.0%
2004	$ 3,447,813	1.3%
2005	$ 4,016,616	16.5%
2006	$ 4,151,784	3.4%
Management/Non-Union		
2002	$ 25,845,690	
2003	$ 17,194,176	-33.5%
2004	$ 15,513,673	-9.8%
2005	$ 20,882,720	34.6%
2006	$ 22,001,952	5.4%
Unionized		
2002	$ 101,003,650	
2003	$ 95,139,201	-5.8%
2004	$ 97,278,259	2.2%
2005	$ 104,511,440	7.4%
2006	$ 110,356,242	5.6%

Response

a) and b)

For the years 2004, 2005, 2006 and 2007, the attached table (Attachment A)contains by representation group: number of employees, total wages, per cent change in total compensation, average wage, per cent change in average wage and benefits.

As noted at Exhibit C1, Tab 3, Schedule 1, Page 1, "Hydro One utilizes a work-based approach to staffing, whereby the Company resources according to work programs rather than plans the work around the number of internal resources available". Consequently, the requested information for the forecast year 2008 is not available.

2004						
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	571	36,164,442		10,216		
MCP	287	36,904,235		191	19,793	n/a
PWU	3,080	246,066,961		13,339	2,099	n/a
SOCIETY	935	85,096,183		6,663	182	n/a
Total	**4873**	**404,231,822**				
2005						
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	594	34,788,694	33.51%	6,952		
MCP	322	41,337,068	-0.95%	459	17,628	3,855
PWU	3,280	262,822,737	-1.12%	13,393	811	2,876
SOCIETY	882	58,938,274	13.58%	2,767	54	2,352
Total	**5078**	**397,886,774**				
2006						
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	598	39,153,993	12.55%	9,828		
MCP	476	59,707,957	44.44%	120	9,239	3,624
PWU	3,495	294,019,129	11.87%	16,901	1	2,901
SOCIETY	732	66,443,825	12.73%	2,030		3,390
Total	**5301**	**459,324,903**				
2007						
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades	740	50,810,389	29.77%	9,972		
MCP	524	67,717,643	13.41%	121	12,690	3,879
PWU	3,825	306,580,259	4.27%	13,439	0	2,788
SOCIETY	804	70,417,819	5.98%	2,955	8	2,629
TOTAL	**5893**	**495,526,109**				
2008						
REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	% CHANGE	Average Overtime	Average Incentive	Benefits per EE
Building trades						
MCP						
PWU						
SOCIETY						
TOTAL	**7079**	**580,700,000**				

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #21 List 1

Interrogatory

Reference: Exhibit C1-3-2 Appendix "A" Page 2 line 5 (table) and Line 22

Questions:

a) Provide a Comparison of Pension Costs for 2006 and 2007 in the same format as the table at line 5.

b) Provide a Summary of the Pension Valuation submitted to FSCO in 2007.

c) Provide a commentary and Comparison to the previous actuarial valuation, including implications and costs for 2008 and beyond.

Response

a. Please refer to the response to Exhibit H, Tab 1, Schedule 75.

b. Summary of Results:

In '000s

	Valuation of Dec. 31, 2006	Valuation of Dec.31, 2003
Smoothed Value of Assets	$4,586,364	$4,141,237
Actuarial Liability	$4,802,087	$4,308,535
Funding Shortfall	($215,723)	($167,298)
Total Current Service Cost	$87,040	$74,565
Est. Members' Required Contributions	$16,555	$14,477
Est. Employers' Current Service Cost	$70,485	$60,088
Employer's Current Service Costs as % of Members' Pensionable Earnings	20.3%	20.4%

Minimum Special Payments	$23,917	$16,769
Est. Minimum Employer Contribution for year	$94,402	$76,857

c. The valuation establishes Hydro One's required level of contribution to the plan. For external reporting purposes, Hydro One records pension costs on a cash basis. As a result, the amount of funding contributions required by the valuation will also be reflected in the financial results. Pension costs are attributed to labour and charged either to operations, or capitalized as part of the costs of fixed assets.

The increase in funding contributions from the prior valuation in 2003 is a result of increased service cost due to higher staff growth and changes in actuarial assumptions, partially offset by the impact of asset gains. Assumptions in the 2006 valuation are consistent with that currently used by other pension plans and the current economic environments.

The valuation report submitted to FSCO in September 2007 will establish a level of contribution of about $95 million for the three year period 2007 through 2009. The actual contribution will vary with the level of the regular staff complement. Of the total funding contribution, roughly 62% is expected to be charged to operations.

Contributions commencing in 2010 will be based on a valuation to be prepared no later than December 31, 2009 and will depend on future investment performance, market interest rates, changes in benefits and actuarial assumptions.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #22 List 1

Interrogatory

Reference: Exhibit C1, Tab 4, Schedule 2, Page 14-16 and Table 2

Preamble: *In the OEB's Decision with Reasons on Hydro One's recent Transmission rate filing (Ref EB-2006-0501), issued on August 16, 2007, the Board stated "in the [compensation] study that Hydro One is [now] preparing, the Board expects it to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities". A broad indicator of workforce productivity improvement is provided in Figure 3, which displays the amount of work accomplished per regular staff count (as indicated by work program spend in $million per regular staff count) for Hydro One Networks (total Distribution and Transmission businesses).*

Questions:

a) Why is the amount of work ($ spend) per regular staff count, a good measure?

b) Is the measure circular in that $ spend includes a high amount of staff/labour costs.

c) Compare the Amount of work per staff count to a classical Total Factor Productivity Factor in terms of inputs and outputs.

d) Breakdown the data and compare the Total Spend per employee between Transmission and Distribution.

e) Has HO conducted a TFP analysis for either Tx or Dx as have the Ontario (and other) gas utilities? If not why not? If so, then provide the results of the study.

f) How do HO labour rates compare to the other utilities in Table 2. Is the $million spend per employee a function of labour rates.

g) Compare HO Dx productivity 2003-2007 to the Board Approved Productivity Factor (X Factor) of 1.1 % for 2nd Generation IRM.

Response

a) As noted in the filing the amount of work per staff is used as a broad indicator, not a specific measure, of the utilization of staff, thus productivity. Utility industry information has not revealed a commonly-used productivity measure. This broad measure shows that despite a projected 40% increase in Hydro One

Networks Distribution and Transmission businesses' work program expenditures between 2006 and 2008, over this same time period the regular staff count is expected to only have grown by 23% and total staff resources (regular and non-regular) by 34%. This is an indication that Hydro One is getting more work done without a corresponding increase in resource levels.

b) The indicator uses a standard labour productivity formula of output /input and it is normal for such a tool is used to provide data and direction not specific measurement.

c) The data used for the indicator is the amount of work accomplished per regular staff count (as indicated by work program spend in $million per regular staff count) for Hydro One Networks (total Distribution and Transmission businesses). As noted in "b)" this is a standard labour productivity indicator and reflects the short-term, approximate, nature of the indicator and the comparisons. The tool referred to in the Interrogatory, "classical Total Factor Productivity Factor" and its variants such as Multi-Factor Productivity, tend to be more subjective, require a longer-time frame and have greater reliance on more specific data.

d) Hydro One does not specifically assign staff to its Transmission or Distribution businesses and has an integrated workforce. Consequently, Total Spend per employee cannot be provided for each of the Transmission and Distributions businesses."

e) No, Hydro One has not conducted a TFP analysis for either Tx or Dx.

Hydro One understands that TFP is used in regulatory environments such as the OEB's 2nd Generation IRM as part of the X-Factor, and was utilized to arrive at a generic X-Factor which is applied to all LDC's .

Neither the X Factor nor the TFP portion of the X-Factor in the OEB's 2nd Generation IRM is defined by the OEB in a manner that would allow OEB regulated LDCs to estimate company specific historic or forecast X-Factors in a consistent manner. Further, a regulatory construct such as TFP would not be useful measure within Hydro One to plan and track cost efficiency savings as the cost efficiency initiatives are identified and reviewed as part of the annual business planning process.

f) Hydro One has not compared its labour rates to the three identified utilities. Two of these utilities, Hydro Ottawa and Toronto Hydro, did participate in the "2007 Comparison of Labour Rates & Overtime Policy" prepared by HayGroup and which was filed as evidence in this application. There was an agreement with the utilities who participated in the Benchmarking study that the information provided would be kept confidential. Confidentiality is a common and important element

of benchmarking which encourages participation and therefore a higher quality product than might otherwise be available. While Hydro One recognizes interveners' interest in the data, requiring the disclosure of information that belongs to 3rd parties and was collected on a confidential basis would jeopardize future benchmarking opportunities. As a result Hydro One cannot conjecture how its labour rates compare to these three specific utilities.

The measure "$million spend per employee" is not a function of labour rates since expenditures include labour as well as other major cost elements such as material, equipment, Inergi costs and other contract costs, and overheads.

g) The 2nd Generation IRM X Factor is in fact 1% and not 1.1% as stated by VECC in its question.

Hydro One has provided the following estimation of annual incremental cost savings for its Distribution business in Exhibit C1, Tab 4, Schedule 2, Page 6, Table 1:

Table 1
Total Incremental Cost Savings – Distribution

	2004	2005	2006	2007 Bridge	2008 Test	Total
OM&A Savings ($M)	13.4	10.5	5.9	3.3	7.5	40.7
Capital Savings ($M)	9.5	8.1	4.6	1.0	2.1	25.4
Total Savings ($M)	23.0	18.6	10.5	4.4	9.6	66.1
Total Spend** ($M)	**618**	**679**	**797**	**1,006**	**1,055**	**4,155**
Savings as % of Total Spend	**3.7%**	**2.7%**	**1.3%**	**0.4%**	**0.9%**	**1.6%**

** Total Spend includes capital plus OM&A expenditures

The X Factor in the OEB's 2nd Generation IRM is not defined by the OEB in a manner that would allow OEB regulated companies to estimate company specific historic or forecast X-Factors. However, conceptually, the cost savings quantified in the above table would be included in a Networks X-factor, if it was possible to calculate such a factor.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #23 List 1

Interrogatory

Reference: Exhibit C1 Tab 5 Schedule 1 Pages 4 -5 and Tables 1-4
Preamble: *The allocation of Asset Management, Operating and Customer Care Management costs is based on a time study, as submitted in the Transmission submission EB-2006-0501 Exhibit C1-5-1. This time study is still relevant and yields an appropriate result.*

Questions:

a) Provide a Summary of the 2008 Common Cost Allocation for Dx in the same format as Table 2 of C1 Tab5 Schedule 1 in EB-2005-0501 For convenience please include Table 2 for Tx including any necessary updates.

b) Refile the Rudden Report Exhibit C1T5 S1 of EB-2005-0501.

c) Refile the Time Study referred to above in this Proceeding.

d) Why is only ~$200,000 of Common CC&FS costs allocated to Hydro One Inc.? Is this a direct allocation or based on a time study or other cost drivers. Please provide details.

e) Why are no Asset Management Costs Allocated to Hydro One Inc.

f) Confirm if Hydro One Inc was an identified Business Unit In the Rudden Report and whether Hydro One Inc was One of the "buckets" for time study allocations or included in "Other".

g) How many "Buckets" were used ie Hydro One Networks (Tx and Dx) and "Other" or a larger number?

h) As well as Time allocation, indicate how much of the indirect allocations listed in Table 4 (totals) are based on other cost drivers and list the major Cost Drivers.

Response

a)

Table 2
Hydro One Common Cost Allocation 2008
Distribution OM&A Costs ($Millions)

Total Charges		Direct Charges		Inergi Charges		Common Charges	
Sustaining	280.0	Sustaining	280.0	Sustaining	0.0	Sustaining	0.0
Development	9.1	Development	9.1	Development	0.0	Development	0.0
Operations	13.4	Operations	3.9	Operations	0.0	Operations	9.5
Shared Services & Other	170.8	Shared Services & Other	0.8	Shared Services & Other	76.7	Shared Services & Other	93.3
Taxes	4.5	Taxes	4.5	Taxes	0.0	Taxes	0.0
Total	477.7	Total	298.3	Total	76.7	Total	102.8

Table 2
Hydro One Common Cost Allocation 2008
Transmission OM&A Costs ($Millions)
(As provided in EB-2006-0501 (most recent available)

Total Charges		Direct Charges		Inergi Charges		Common Charges	
Sustaining	200.9	Sustaining	200.9	Sustaining	0.0	Sustaining	0.0
Development	8.1	Development	8.1	Development	0.0	Development	0.0
Operations	46.2	Operations	15.2	Operations	0.0	Operations	31.0
Shared Services & Other	57.1	Shared Services & Other	(73.9)	Shared Services & Other	28.0	Shared Services & Other	103.0
Taxes	75.1	Taxes	75.1	Taxes	0.0	Taxes	0.0
Total	387.5	Total	225.4	Total	28.0	Total	134.0

b. See Attachment A.

c) Asset Management time study included in (b) above.

d) Approximately $200K of CCFS costs are allocated to Hydro One Inc; this represents the costs for activities performed exclusively for the benefit of the sole shareholder of Hydro One Inc. The assignment of costs is based on either time studies or appropriate cost drivers according to the specific services being provided, and is consistent with the methodology as per the Rudden Study. The following are the details of the costs and associated cost drivers for Hydro One Inc.

1

HYDRO ONE COMMON CORPORATE COST MODEL
YEARLY COST DISTRIBUTION

				2008 Cost
Group	Function or Services	Activities Performed	Cost Driver	Share-holder Only
Finance	Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	41,849
Finance	Taxation	Tax Planning	OperMaint Exp_Assets Blend	4,165
Finance	Taxation	Support Debt issuance	Total Debt	0
Finance	Taxation	Special Projects	OperMaint Exp_Assets Blend	0
Finance	Taxation	Support regulatory filings	Regulatory Dept. Labor (Internal)	0
Finance	Taxation	Support Construction activities	Capital expenditures	391
Finance	Taxation	Other departmental activities	Tax Dept. Labor (Internal)	641
Finance	Taxation	Tax Consultants	Tax Dept. Labor (Internal)	6,263
Finance	Taxation	General Departmental activities	Tax Dept. Labor (Internal)	2,923
Network Executive	Internal Audit & Risk Mgmt	Finance	Finance Labor Costs (Internal)	1,118
Network Executive	Internal Audit & Risk Mgmt	General Departmental Expenses	IntAudit Dept. Labor (Internal)	39
General Counsel	Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	54,358
General Counsel	Law	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)	19,036
General Counsel	Law	General departmental expenses	GC_Law Dept. Labor (Internal)	1,464
HOI	Chair	OVERALL ASSIGNMENT OF TIME	Non-energy Rev_Assets Blend	3,090
HOI	General Counsel - VP	OVERALL ASSIGNMENT OF TIME	Non-energy Rev_Assets Blend	5,679
HOI	General Counsel - VP	General Departmental Expenses	GC_Corp Dept. Labor (Internal)	750
HOI	Corp. Secretariat	OVERALL ASSIGNMENT OF TIME	Non-energy Rev_Assets Blend	2,273
HOI	Corp. Secretariat	General Departmental Expenses	GC_Secy Dept. Labor (Internal)	1,000

HYDRO ONE COMMON CORPORATE COST MODEL
YEARLY COST DISTRIBUTION

HOI	CFO Office	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend	6,039
HOI	CFO Office	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend	6,039
HOI	CFO Office	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend	3,020
HOI	CFO Office	Support BOD	Non-energy Rev_Assets Blend	0
HOI	CFO Office	Ensure access to capital on reasonable terms	Total Capital	3,020
HOI	CFO Office	OTHER DEPARTMENT ACTIVITIES	CFO Dept. Labor (Internal)	91
HOI	CFO Office	General departmental expenses	CFO Dept. Labor (Internal)	9,045
TOTAL				172,291

e) The Asset Management group is responsible for the utility's operating assets, including investment strategy and investment planning. There are no services provided to Hydro One Inc; therefore no costs are assigned.

f) Confirmed, Hydro One Inc. was an identified business unit in the Rudden Study, and was one of the buckets used for time study allocations.

g) A total of six buckets was used as follows:
   a. Hydro One Networks Tx
   b. Hydro One Networks Dx
   c. Hydro One Telecom Inc.
   d. Hydro One Brampton Inc.
   e. Hydro One Remotes Communities
   f. Hydro One Inc.

h) Of the total $84.2M costs in Table 4, $60.7M is allocated based on time studies and other drivers. A listing of the drivers follows:

DRIVER	DESCRIPTION
Physical	
Asset Manager	Results of Asset Manager time study, December 2004
Facilities SqFt	Square feet of facilities included in LBSS activities, 12/31/06 values (Shared)
FTEs	Full time equivalent employees, 12/31/06 values (Shared)
Invoices To Vendors	Self-explanatory, 2006 and 12/31/06 values (Shared)
ProgramProjectCosts	Program and Project Costs for Capital and OM spending on Transmission and Distribution for 2006
Other Bills To Customers	Bills to customers other than retail bills to customers, 2006 values
Telephones	Self-explanatory, 2006 and 12/31/06 values (Shared)
Workstations	Self-explanatory, 2006 and 12/31/06 values (Shared)
Financial ($ millions)	
Capital expenditures	Budgeted amounts for 2008
Gross utility plant	Projected balances as of 12/31/07
Gross utility plant xB	Gross utility plant excl. Brampton
Gross utility plant xBxTxR	Gross utility plant excl. Brampton, Telecom, Remotes
Market Ready	Hydro One Networks Market Ready Transition Costs
Net utility plant	Projected balances as of 12/31/05
Non-energy revenue	Budgeted amounts for 2007
Oper Maint Cap	Budgeted amounts for 2007
Oper Maint Cap xB	Oper Maint Cap excl. Brampton
Oper Maint Cap xBxT	Oper Maint Cap excl. Brampton, Telecom
Oper Maint Cap xBxTxR	Oper Maint Cap excl. Brampton, Telecom, Remotes
Oper Maint Exp	Budgeted amounts for 2007
Total Assets	Projected balances as of 12/31/07
Total Assets xBxTxR	Total Assets excl. Brampton, Telecom, Remotes
Total Capital	Projected balances as of 12/31/07
Total Debt	Projected balances as of 12/31/07
Total Revenue	Budgeted amounts for 2007
Total Revenue xB	Budgeted amounts for 2007 excl. Brampton
Derived Financial	
Assets	Average Net utility Plant, Total Assets
Non-energy Rev_Assets Blend	50% Non-energy Revenue, 50% Assets
Non-energy Rev_Assets Blend xB	Non-energy Rev_Assets Blend excl. Brampton
Non-energy Rev_Assets Blend xBxTxR	Non-energy Rev_Assets Blend excl. Brampton, Telecom, Remotes
OperMaint Exp_Assets Blend	50% Oper Maint Exp, 50% Assets
Non-energy Rev_Workstations Blend	50% Non-energy Revenue, 50% Workstations
Non-energy Rev_Workstations Blend xB	Non-energy Rev_Workstations Blend excl. Brampton
Total Revenue_Assets Blend	50% Total Revenue, 50% Assets
Total Revenue_Assets Blend xBxTxR	Total Revenue_Assets Blend excl. Brampton, Telecom, Remotes

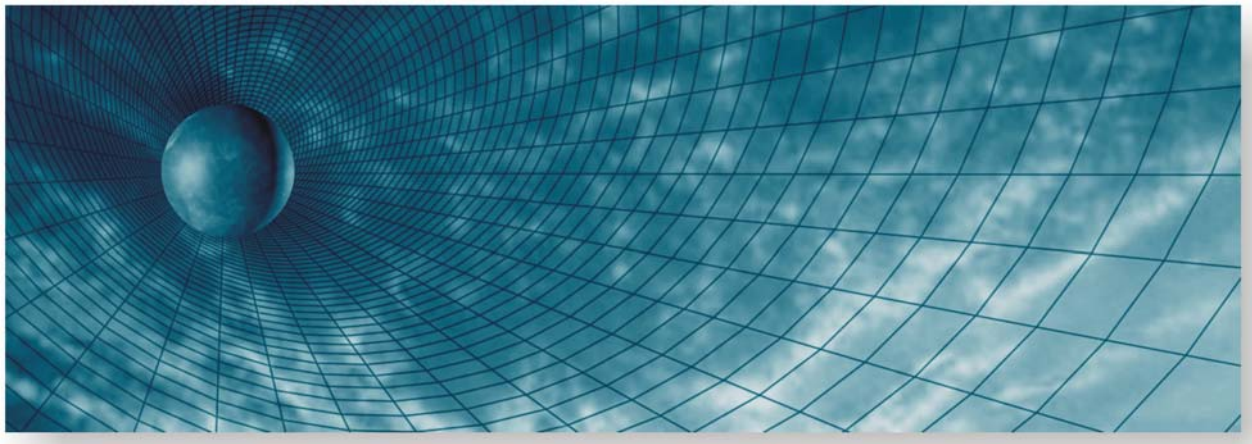
Report to

Hydro One Networks Inc.

Regarding

Review of Implementation of Common Corporate Costs Methodology

May 31, 2006



R.J. Rudden ASSOCIATES
A Black & Veatch Company

Review of Implementation of Common Corporate Costs Methodology

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Review of Implementation of Common Corporate Costs Methodology

EXHIBITS

Exhibit A – Detailed Description Of Common Corporate Functions And Services

Exhibit B –Budgeted Costs And Activities For Common Corporate Functions And Services- 2007 Budget

Exhibit C –Activity Cost Assignments To Business Units- 2007 Budget

Exhibit D – Cost Drivers

Exhibit E – Activity Costs Distributed To Business Units- 2007 Budget

Exhibit F – Summary Of CCFS Costs Distributed To Business Units- 2007 Budget

Exhibit B (2008) –Budgeted Costs And Activities For Common Corporate Functions And Services- 2008 Budget

Exhibit C (2008) –Activity Cost Assignments To Business Units- 2008 Budget

Exhibit E (2008) – Activity Costs Distributed To Business Units- 2008 Budget

Exhibit F(2008) – Summary Of CCFS Costs Distributed To Business Units- 2008 Budget

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Review of Implementation of Common Corporate Costs Methodology

I. SUMMARY

R. J. Rudden Associates ("Rudden" or "we") is pleased to submit this Report on our Review of Implementation of Common Corporate Costs Methodology ("Review") to Hydro One Networks Inc. In 2004, Rudden was engaged by Hydro One Networks Inc. to recommend a best practice methodology to distribute the costs of providing the common corporate functions and services ("CCFS"), including costs under its outsourcing contract with Inergi LP, to Hydro One Inc. and its various subsidiaries. Rudden recommended, Hydro One adopted, and the Ontario Energy Board ("OEB") approved a methodology, described in our *Report on Common Corporate Costs Methodology Review* dated May 20, 2005 ("2005 Report"). In this Report, that OEB-approved methodology is applied to Business Plan 2007-2011 ("BP 2007") data for the years 2007 and 2008. No changes were made to the OEB-approved methodology. The reader is referred to the 2005 Report for additional information.

Hydro One Inc. is wholly owned by the Province of Ontario. It operates primarily through wholly owned subsidiaries: Hydro One Networks Inc., which includes the Transmission business and the Distribution business; Hydro One Brampton Inc. and Hydro One Brampton Networks Inc. ("Brampton"); Hydro One Remote Communities Inc. ("Remotes"); and Hydro One Telecom Inc. ("Telecom"). See Section III.D Table 6- Business Units for further information on these businesses.

CCFS comprises the functions and services identified below; Exhibit A further describes the functions and services.

TABLE 1 FUNCTIONS AND ACTIVITIES IN CCFS	
• Hydro One Inc. Corporate Office	• Customer Support Operations
• Corporate Services	• Settlements
• Finance	• Finance and Accounting Services
• General Counsel	• Human Resources
• Telecom Services	• Supply Management Services
• ETS- Applications Support and Infrastructure Support	

The BP 2007 includes approximately C$218.3M in 2007 and C$219.2M in 2008 to provide the common corporate functions and services. These functions and services are provided, and the costs are incurred, for the benefit of the business units listed in Section III.D Table 6- Business Units.

Approximately half of the CCFS costs are incurred under an outsourcing arrangement with Inergi LP ("Inergi"). In this Report, CCFS includes the portions of Inergi services identified in BP 2007-2011 as sustainment.

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Our approach was designed to ensure compliance with OEB precedent including Docket RP-2002-0133, and compliance with relevant provisions of the Affiliate Relationships Code for Electricity Distributors and Transmitters, November 24, 2003 revision. In addition, we addressed the following aspects: Cost incurrence (Are the costs needed to perform services needed by the business units?); Cost allocation (Were the costs appropriately allocated to the recipient business units?) and Cost / benefit (Did the benefit received equal or exceed the cost?).

Our approach is described in Section II- Approach. Our approach uses direct assignment of costs to business units when possible and, consistent with OEB precedent, uses costs drivers to allocate costs when direct assignment is not possible. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The use of cost drivers conforms to OEB precedent, including Docket RP-2002-0133.

The guiding principle that Rudden used in assigning cost drivers was cost causation, which means there is a causal relationship between the cost driver and the costs incurred in performing the activity. Where cost causation cannot be easily implemented or established, selecting cost drivers based on benefits received is a fair and consistent treatment. Other factors considered included practicality; stability; and materiality.

Consistent with standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., counts of workstations, counts of FTEs, budgeted amounts), subject only to overall reasonableness and actual contrary knowledge, but without independent confirmation.

This Report presents the Total Amounts and the amounts in the Transmission business unit. All amounts in this Report are in Canadian dollars.

Table 2 shows the CCFS costs distributed to each business unit for 2007 and 2008.

TABLE 2 TOTAL CCFS COSTS, 2007 AND 2008 BUDGET

Business Unit	2007 Budget ($000s)	2008 Budget ($000s)
Transmission	$ 73,136	$ 73,419
Distribution	121,046	120,986
Others	24,161	24,765
Total CCFS Costs	$218,343	$219,170

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II. APPROACH

The purpose of our Common Corporate Costs Methodology Review was:

> Recommend a best practice methodology to distribute the cost of providing Hydro One Inc.'s common corporate functions and services among the business units that use the functions and services. The methodology must use cost drivers that reflect causality and benefit and meet the requirements of the OEB. The cost drivers should also take into account cost effectiveness, simplicity, regulatory acceptability and flexibility.

Our approach was to:

- Identify the functions and services included in CCFS;
- Identify activities that are performed in order to provide the CCFS;
- Distribute the 2007 and 2008 budgeted cost to perform each function and service among the activities required to perform it, based on time and/or cost studies;
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not.

A. Principles Of Cost Distribution

There are two methods to distribute shared costs among business units – Direct Assignment and Allocation. Direct Assignment is used when the portion of an activity used by a business unit can be reasonably established. Direct assignment is preferable to Allocation because it is based on a more direct relationship. Approximately 33% of CCFS budgeted costs were assigned directly to one or more of the business units.

Allocation is used when more than one business unit uses an activity, but the portions of the activity that each uses cannot be directly established. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The principles used by Rudden to assign cost drivers are discussed below.

B. Cost Drivers

As stated above, a cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The guiding principle that Rudden used in assigning

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cost drivers was cost causation, which means that there is a causal relationship between the cost driver and the costs incurred in performing the activity. In some cases, cost causation cannot be easily implemented or established, in which cases selecting cost drivers based on benefits received is a fair and consistent treatment.

Other factors considered included practicality (cost drivers should be understandable, obtainable at reasonable cost and objectively verifiable); stability (estimates should be reasonably accurate and unbiased); and materiality (when choosing between cost drivers, small differences can often be ignored in favor of practicality and stability).

C. Types of Cost Drivers

Cost drivers can be classified as External or Internal. External drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts. Internal drivers are based on values computed as part of the allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised. Table 3 describes the types of cost drivers.

TABLE 3 DESCRIPTION OF TYPES OF COST DRIVERS

TYPE	DESCRIPTION	EXAMPLES
External Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Number of customers, employees, phone calls or workstations; time studies; MWh or MW
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Oper Maint (expense), Total assets, Total capital, Total revenue
Blended	Weighted combinations of other drivers, used when one or more drives are applicable and none is clearly preferable; weights determined by judgment	Non-energy Rev_Assets Blend = 50% weight for Non-Energy Revenue and 50% weight for Assets

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TABLE 3 DESCRIPTION OF TYPES OF COST DRIVERS		
TYPE	**DESCRIPTION**	**EXAMPLES**
Driver *xBusiness Unit*	Any driver may be modified by excluding one or more business units to which the activity does not apply	Cost driver for payroll preparation activity is FTEs (Full-Time Employees), but Brampton business unit prepares its own payroll and does not use the shared service, therefore activity cost driver is called FTE xB (Full-Time Employees excluding Brampton)
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

Table 4 summarizes the types of cost drivers used to assign the CCFS costs for 2007. The results for 2008 would be very similar.

TABLE 4 DIRECT ASSIGNMENTS AND COST DRIVERS USED FOR CCFS COSTS		
TYPE	**2007 $ ASSIGNED (C$ 000s)**	**% OF TOTAL**
Direct Assignment	$71,351	32.7%
Physical	36,414	16.7%
Financial	72,949	33.4%
Internal	37,629	17.2%
Total CCFS Costs	$218,343	100.0%

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D. Summary of Tasks

Our Review comprised the tasks listed in Table 5. Where the results of a task or other information are presented in an exhibit, the exhibit is identified. Section III of this report, Description of Each Task, provides a detailed discussion of each task.

TABLE 5 TASKS

TASK	DESCRIPTION	EXHIBITS
Task 1	*Identified the functions and services* included in the common corporate functions and services (CCFS).	Table 1, Exhibits A, B
Task 2	*Identified the activities* that are performed in order to provide each of the CCFS identified in Task 1.	Exhibit B
Task 3	*Determined 2007 and 2008 budgeted* cost for the CCFS identified in Task 1.	Exhibit B
Task 4	*Identified the business units* (service recipients or beneficiaries) which use the CCFS.	Table 6
Task 5	*Distributed total budgeted resources* (time for labor and cost for non-labor and Inergi) required for each of the CCFS identified in Task 1, among the activities identified in Task 2.	Exhibit B
Task 6	*Assigned activity costs* to business units.	Exhibit C
Task 7	For activities where less than all of the resources were directly assigned to business units in Task 6, *assigned a cost driver* that reflects cost causation.	Exhibits C
Task 8	*Populated* the cost drivers.	Exhibit D
Task 9	*Computed total cost of CCFS* distributed to each business unit.	Exhibits E, F
Task 10	*Reviewed* inputs and results for reasonableness and consistency.	

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III. DESCRIPTION OF EACH TASK

A discussion of each subtask follows, including the purpose of the subtask, the detailed steps performed, the source of the information and the results. In most cases the detailed results are presented in exhibits.

Changes from the information in the 2005 Report were minor.

A. Task 1: Identified Functions and Services Included in CCFS

The purpose of this subtask was to identify and understand the common corporate functions and services; the allocation of the cost of the CCFS is the goal of this Review.

The CCFS support the Hydro One Networks Inc. Transmission and Hydro One Networks Inc. Distribution business units and also support the Remotes, Brampton and Telecom business units of Hydro One Inc. as well.

CCFS comprises the functions and services identified in Table 1 in Section I.- Summary. Exhibit A further describes the functions and services. This information was obtained from Hydro One Inc. internal documents, the Inergi Scopes of Work, and discussions with Hydro One Inc. personnel.

B. Task 2: Identified Activities Performed to Provide Each of the CCFS

The purpose of this subtask was to identify the activities that are performed in order to provide each of the CCFS.

Functions and services (identified in Task 1) are performed for the benefit of the business units, while *activities* (discussed in this subsection) are the tasks performed in order to render the functions and services. *Functions and services* can be measured in benefits received, while *activities* are measured in resources used.

To distribute the resources used in providing the CCFS among the business units on the basis of cost causation, it is necessary to identify and understand the activities that are performed to provide the CCFS.

The activities performed to provide the CCFS were identified in discussions among Hydro One Inc. management personnel, Rudden, and the Hydro One manager responsible for each of the functions and services identified in Task 1. Rudden summarized the information, following which the Hydro One managers verified that the list of activities was complete and the descriptions were accurate.

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Exhibit B and Exhibit B (2008) list each of the CCFS (column A) and the activities performed to provide the CCFS (column B). Exhibit B and Exhibit B (2008) also shows other information that will be discussed under Task 3, Task 5 and Task 7.

C. Task 3: Determined 2007 and 2008 Budgeted Cost for Each of the CCFS

This task was to obtain the 2007 and 2008 budgeted cost for each of the CCFS. As part of this subtask, Rudden identified the labour and non-labour portions of the budget for each of the CCFS and identified and obtained descriptions of major non-labour items.

The information was obtained from Hydro One Inc. Exhibit B and Exhibit B (2008) show the 2007 and 2008 budgeted cost, respectively, for each of the CCFS (column E).

D. Task 4: Identified Business Units

The purpose of this task was to identify the business units that use the common corporate functions and services. The information was obtained from Hydro One Inc. In addition, in discussions with the management of each business unit, it was confirmed that the business unit uses the common corporate functions and services for which it was assigned costs. The business units that use the CCFS are listed in Table 6.

TABLE 6 BUSINESS UNITS

BUSINESS UNIT	DESCRIPTION
Trans-mission	Owns and operates substantially all of Ontario's electricity transmission system.
Distribution	Owns and operates a distribution system which spans approximately 75% of Ontario and serves approximately 1.1 million customers.
Brampton	Owns, operates and manages electricity distribution systems and facilities in Brampton, Ontario.
Remotes	Owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario
Telecom	Sells dark fibre to other carriers and high bandwidth telecommunication services to carriers, Internet service providers and others.

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TABLE 6 BUSINESS UNITS	
BUSINESS UNIT	**DESCRIPTION**
Shareholder	Represents activities performed exclusively for the benefit of the sole shareholder of Hydro One Inc.
Note- The cost distribution methodology also identified the costs to include in the Materials Surcharge, which are included in materials costs and ultimately charged to business units.	

E. Task 5: Distributed Total Budgeted Resources for Each CCFS Among Activities

The purpose of this task was to distribute the resources (time for labour and costs for non-labour and Inergi) required for each of the CCFS identified in Task 1, among the activities identified in Task 2. In subsequent tasks, the cost of each activity was either directly assigned to one or more business units or allocated using cost drivers.

To distribute budgeted labor costs, the Hydro One manager responsible for each CCFS unit estimated the portion of annual time spent by the personnel under his or her supervision on each of the activities identified in Task 2. Some managers based their estimates on concurrent time records that they maintain, some conducted interviews with their personnel, and some used their informed judgment. The information provided by the managers was reviewed by Hydro One Inc. and Rudden, and compared to information in the 2005 Report, and was found to be reasonable.

To distribute the budgeted non-labour costs, $22.0M, or 78.0%, of the 2007 budgeted total of $35.1M, were specifically examined and distributed based on direct assignment or allocation. This included OEB invoices, communications programs, insurance costs and claims, human resources programs, labour Relations programs, actuarial and tax consultants, audit fee and donations. The balance of non-labour costs includes items such as training and development, non-specific expenses and general expenses (such as travel).

The costs of the functions and services provided by Inergi were distributed among the activities, based on information provided by Hydro One Inc., assignments and allocations by Hydro One Inc. and Rudden, and the application of judgment by Rudden. The approach for each of the CCFS provided by Inergi is described below.

- Customer Support Operations – Hydro One Inc. estimated the portion of total effort required by Inergi to perform each activity. The amounts were very close to the historical efforts when Hydro One personnel performed the work.

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- Settlement – Only one activity, no distribution of costs required.
- Supply Management Services – Hydro One Inc. estimated the portions of total effort required by Inergi to perform each activity.
- Finance – Rudden assigned costs among activities based on historic salaries of Hydro One employees that formerly performed similar activities.
- Human Resources – Only one activity, no distribution of costs required.
- Enterprise Technology Services –Hydro One analyzed the activities distributed the 2007 costs among the following ETS activities: customer support operations applications; finance applications; human resources applications; Passport applications; Market Ready applications; telecom services; and infrastructure services.

The results of this task are shown in Exhibit B and Exhibit B (2008), which shows the percent of 2007 and 2008 total budgeted cost, respectively, for each CCFS that was distributed to each activity (column F), and cost distributed to each activity (column G).

F. Task 6: Assigned Activity Costs To Business Units

The purpose of this task was to assign, among the business units identified in Task 4, the resources (time for labour and costs for non-labour and Inergi) for each activity identified in Task 2. In subsequent tasks, these assignments were used to distribute the costs of each activity among the business units.

This task was performed concurrently with Task 5 – Distributing Total Budgeted Resources for Each CCFS Among Activities. The results of this task are shown in Exhibit C and Exhibit C (2008) for 2007 and 2008, respectively.

For each activity identified in Task 2, the Hydro One manager responsible for the CCFS was asked to divide the resources among one or more business units, based on which business units caused the costs to be incurred. Wherever possible, the costs were assigned directly. The amounts assigned directly are shown in Exhibit C and Exhibit C (2008), columns C through E.

When less than 100% of an activity was assigned directly, it was allocated among the business units using cost drivers, as described in Task 7.

G. Task 7: Assigned Cost Drivers

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As discussed above, when an activity cannot be 100% directly assigned to one or more business units, it must be allocated using a cost driver. The purpose of this task was to find appropriate cost drivers for the activities which were not 100% directly assigned in Task 6. In subsequent tasks, the cost drivers were used to distribute the activity costs among the business units.

The portion of each activity not directly assigned in Task 6 was determined to be:

- Caused by Transmission and Distribution only, and the split cannot be determined (Exhibit C and Exhibit C (2008), column G), or
- Caused by Transmission or Distribution and at least one other business unit, and the split cannot be determined. (Exhibit C and Exhibit C (2008), column H), or
- Assigned to be recovered in Material Surcharge (Exhibit C and Exhibit C (2008), column I).

The principles that Rudden used to assign cost drivers are discussed on page 3, section II.B. – Cost Drivers, including both economic criteria and implementation considerations. Rudden assigned cost drivers by applying the principles discussed above, Rudden's experience in performing cost allocation studies, consultations with Hydro One Inc. to ascertain the nature of each activity, and knowledge of industry practices and regulatory requirements.

Section II.B. Types of Cost Drivers describes the types of cost drivers. The cost driver assignments for each activity are shown in Exhibit B and Exhibit B (2008), column C and Exhibit C and Exhibit C (2008), column F.

H. Task 8: Populated Cost Drivers

The purpose of this activity was to determine the values of each cost driver that are attributable to each business unit, in order to distribute the costs of each activity among the business units. The information was obtained from Hydro One Inc.

Exhibit D lists and describes each cost driver. The values of each cost driver attributable to each business unit are shown on pages 1, 3 and 5; the portion that each business unit is of the cost driver total is shown on pages 2, 4 and 6.

The Asset Management time study ratios were based on a time study conducted in April 2006, which is described in Section V. The results of the time study were similar to the results of Asset Management time studies performed by Hydro One in March 2003 and April 2006.

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I. Task 9: Computed Total Cost of CCFS Distributed To Each Business Unit

The purpose of this task was to distribute the total cost of each activity among the business units. The amount distributed was the sum of the amounts directly assigned in Task 6 and allocations based on the cost drivers identified in Task 7.

For allocations based on the cost drivers, the amount allocated to each business unit was computed by multiplying the cost to be allocated, shown in Exhibit C and Exhibit C (2008), columns G through I, by the cost driver portion value for the business unit.

The cost drivers were developed by Rudden based on the criteria established on page 3, section II.A. Principles Of Cost Distribution. The cost driver methodology meets the criteria established by the OEB and is consistent with industry practice for allocating the types of costs included in CCFS.

J. Task 10: Reviewed Inputs and Results

The purpose of this task was to ensure that the inputs were reasonable and accurate and that the results were reasonable. This included a review of:

- Proportions of total cost distributed to each business unit
- Levels of total cost and of cost for selected departments, which were reviewed by Rudden in a separate assignment performed for Hydro One Networks Inc.
- Levels of total cost assigned to each business unit

The inputs and results were reviewed by Hydro One Inc. and by Rudden, and the results were then reviewed with each business unit to which the costs of the common corporate functions and services were distributed.

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IV. SUMMARY OF RESULTS

A. Results

Exhibit E and Exhibit E (2008) present the budgeted cost of each activity distributed to each business unit for the 2007 and 2008 budgets (from BP 2007), respectively.

Exhibit F and Exhibit F (2008) summarize the information for each of the common corporate functions and services for the 2007 and 2008 budgets (from BP 2007), respectively.

B. Implementation

This section reports on the resolution of issues related to implementation that were discussed in the 2005 Report.

Absorption of Overage/Underage; True-ups

Hydro One confirms that differences arising from the use of estimates are charged or credited to the appropriate business unit as an end of the year adjustment.

Updates

Hydro One confirms that it is following the schedule for updates recommended in the 2005 Report.

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V. ASSET MANAGEMENT

The Asset Management group, which includes Asset Management and Operators, is responsible for the utility's operating assets, including investment strategy and investment planning. The Operators portion of the group is responsible for the day-to-day operation of the Ontario Grid Control Centre. Work includes 24 hour/day monitoring of grid system status, coordination of system outages and remote operations/switching of Transmission system assets. Substantially all Asset Management and Operators costs are labor and labor-related.

Hydro One determined the portion of Asset Management costs devoted to capital projects by performing a time study for these personnel for the five-week period ending April 7, 2006. Asset Management personnel are able to determine with reasonable accuracy, on a current basis, the time they spend on Distribution Operations and Maintenance, Distribution Capital Projects, Transmission Operations and Maintenance and Transmission Capital Projects.

It is easier for Asset Management personnel to determine the time spent on these areas, because the projects on which they work are more clearly defined than for the common corporate functions ands services. In addition, a four-week period will closely approximate full-year results for Asset Management, while that is not so for the common corporate functions and services personnel, because their work varies during the year.

A properly performed time study measures cost causation and is widely accepted as a basis for allocating costs. Rudden reviewed the time study method used by Hydro One for Asset Management personnel and found it to be appropriate. It was not practical to perform a full-year study, but any effects of performing the study over four weeks, instead of a full year, are believed to be minimal. To support this judgment, Rudden reviewed the two prior Asset Management studies performed by Hydro One and found that the results are similar.

Therefore, Rudden found the time study to be a proper basis for assigning Asset Management costs between the Distribution and Transmission business units.

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The results of the Asset Management performed by Hydro One for the five weeks ended April 7, 2006 are summarized in Table 7.

TABLE 7 ASSET MANAGEMENT TIME STUDY, APRIL 2006

	Transmission		Distribution		Total	
	Oper. and Maint.	Capital Projects	Oper. and Maint.	Capital Projects	Oper. and Maint..	Capital Projects
Asset Management	41.6%	26.0%	22.8%	9.6%	64.4%	35.6%
Customer Care	3.3%	1.2%	93.9%	1.6%	97.2%	2.8%
Operations	70.4%	6.8%	20.3%	2.5%	90.7%	9.3%
Total Asset Management	50.9%	16.9%	25.9%	6.3%	76.8%	23.2%
Total Transmission and Distribution	67.8%		32.2%		100.0%	

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Review of Implementation of Common Corporate Costs Methodology

GLOSSARY

Brampton means Hydro One Brampton Networks Inc., a wholly owned subsidiary of Hydro One Brampton Inc. Hydro One Brampton Inc. is a wholly owned subsidiary of Hydro One Inc.

CCFS means Common Corporate Functions and Services, a major cost category for Hydro One Networks Inc.

Inergi means Inergi LP, an Ontario limited partnership that provides outsourced services to Hydro One Networks Inc. under a ten-year contract

OEB means the Ontario Energy Board

Remotes means Hydro One Remote Communities Inc., a wholly owned subsidiary of Hydro One Inc.

Review means the Hydro One Shared Functions and Service Review 2004, the subject of this Report

Telecom means Hydro One Telecom Inc., a wholly owned subsidiary of Hydro One Inc.

Rudden means R. J. Rudden Associates, A Unit of Enterprise Management Solutions, Black & Veatch Corporation

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EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Hydro One Inc. Corporate Office	
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
Chair	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary
President and CEO	The CEO's primary accountability is leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. The CEO develops and updates Hydro One's strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.
CFO's Office	The CFO provides Hydro One and its subsidiaries with strategic review and approval with respect to all financial and investment decisions. Services relating to the review of policies and procedures, treasury operations and tax planning, financial control and reporting are also provided by the CFO to Hydro One Inc. and its subsidiaries as required.
Treasurer's Office	Treasurer's Office is responsible for Debt and equity issuance, Capital structure management and oversight of Finance- Treasury function.
Donations	Includes donations made to support injury prevention, corporate donations (e.g. Salvation Army), energy education, United Way support and local community causes.
Corporate Services	
Human Resources	Focused primarily on Employee and Labour Relations.

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EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Labour Relations	Provides full-scale service pertaining to bargaining, Ontario Labour Relations Board hearings, grievance and arbitration hearings, advice and guidance, plus training to all levels of Hydro One management. This involves interaction with 21 different unions and 24 collective agreements**.**
Corporate Communications	Supports all communications initiatives, both external and internal. Interacts with most other Hydro One departments but has a special focus on working with Customer Service department.
Supply Management Services (Hydro One)	Management of the Inergi SMS services; Over-all supply and procurement strategic direction including contracting with outside parties.
Corporate Services- SVP	Oversight of Corporate Services departments
Information Management & Information Technology	Enterprise IT Architecture, Governance of IT architecture, Business Analysis and Information Management, Project Management & Control, Large Project Management, Inergi & Telecom services management.
Finance	
Corporate Controller	Revenue Management; Financial Modeling & Analysis; Corporate Planning & Reporting, Support & Accounting Policy; Corporate Accounting Policies & Systems; Regulatory Finance; Inergi Finance; Financial Strategy

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EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Treasury	• Risk management including insurance purchasing • Insurance claims settlement • Financial risk management-foreign exchange, interest, credit • Cash & banking operations-cash forecasting, strategy & banking relationships, bank account management • Debt management-prospectus, debt issuance, borrowing, maintain relationship with shareholders • Funds management-deployment of short term funds and manage longer term funds • Investor Relations is responsible for: Relationship with shareholders, creditors, equity analysts & rating agencies
Taxation	Meet internal and external tax compliance requirements and reduce the overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, GST, PST, and DRC returns for all entities), tax accounting, lobbying for legislative tax changes, and government tax audits.
Financial Strategy	Provides financial support services, including business case review and preparation, project management, decision support, business valuation, transaction support, deal structuring, and business consulting services.
Internal Audit & Risk Management	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.
General Counsel	

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EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Regulatory Affairs	Coordinate filings with OEB; Manage relationship with OEB; Cost Allocation and Rate Design for regulated Tx and Dx, in particular, rate structures and rates for Tx and Dx Tariffs; Assist implementation of approved Tx and Dx rates; Support transmitters' representative on IESO Technical Panel; Provide load forecasts for all business units of Hydro One and for IESO; Manage MV Star to support wholesale and retail settlement; Provided strategic and analytical support to load research and CDM initiatives.
Regulatory Affairs- OEB Cost	OEB costs for Tx and Dx activities.
Law	Provides legal advice to all business units, acting as an internal "law firm" for the Corporation on most aspects of law affecting it, and is also well acquainted with day- to-day requirements of the Corporation.
Corporate	Oversee and support Law, Regulatory and Corporate Secretariat General Counsel functions.
Corporate Secretariat	Provides direction and analysis in areas of: 1) Board and Committee(s); 2) Support to the Office of the Chair and members of the Board of Directors; 3) Code of Business Conduct; 4) Community Citizenship; 5) Freedom of Information and Privacy, 6) Corporate Archives, 7) Corporate Records, and 8) Corporate Secretariat Support.

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EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Telecom Services	Telecom Services provides telecommunications infrastructure across the Province, including both voice and data. Links staff and business applications at Trinity, Richview TS, Markham and London Call Centers, Mill Creek data centre, 125 field offices (400 total sites including stations) and customers via Call Centres and Web sites.
Customer Support Operations	Inbound Call Handling; Bill Production; Collections; Data Services
Settlements	Wholesale Settlements - Provide settlement and reconciliation services for power procured from the Independent Electricity Market Operator and embedded Retail Generators with due consideration to legislative initiatives for fixed energy prices for low volume customers and Business Protection Plan Rebates, transmission revenues and inter-utility load transfers, and cost of power reporting, and; Retail Settlements - Provide complex billing for interval meter accounts.
Finance and Accounting Services	Accounts Payable Billing; Accounts Receivable (Non-energy related); Fixed Asset and Project Cost Accounting; General Accounting and Planning, Budgeting and Reporting
Human Resources	Payroll
Supply Management Services	Demand Planning, Demand Management and Procurement, Sourcing, Vendor Management and Inventory Management, Process Development and Data Management, Negotiating and managing transportation contract with logistics providers, Asset Disposal

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R.J. Rudden ASSOCIATES
A Black & Veatch Company

EXHIBIT A – DETAILED DESCRIPTION OF COMMON COPORATE FUNCTIONS AND SERVICES	
FUNCTIONS AND SERVICES	**DETAILED DESCRIPTION**
Applications Support	Support the following applications: Customer Support Operations, Finance, Human Resources, Passport, Market Ready, Telecomm Services,
Infrastructure Support	Support the infrastructure including platforms, servers, printers, workstations, IT communications and Help Desk

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EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Human Resources	Administer Compensation & Benefits Programs	FTEs	5,069,000	8.3%	418,760
	Decision support	FTEs		10.2%	518,060
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		13.7%	694,340
	Administer Pension Plan	FTEs		14.4%	727,440
	Administer Inergi HR	Inergi HR (Internal)		4.1%	209,380
	Consulting support to LOBs and corporate functions	FTEs		42.0%	2,128,600
	Director	HR Dept. Labor (Internal)		7.3%	372,420
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs	1,389,000	43.3%	602,000
	Negotiate with Bargaining Units	FTEs		13.1%	181,450
	Participate in grievance and arbitration filings	FTEs		34.9%	485,150
	Participate in OLRB hearings	FTEs		8.7%	120,400
	Internal vacancy management	FTEs		0.0%	0
Communications	Provide communications support for corporate safety program & activities	FTEs	5,527,000	7.7%	427,700
	Provide communications support for customer information requirements	Direct Dx		20.2%	1,119,050
	Provide Media Program for Community Info & Employee Contributions	FTEs		28.4%	1,570,400
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital		15.5%	855,400
	Provide Support to CDM and Other Special Programs	Direct Dx		5.0%	276,350
	Provide other internal communications support	FTEs		7.7%	427,700
	Other departmental activities	Non-energy Rev_Assets Blend		15.4%	850,400
	General departmental expenses	CorpComm Dept. Labor (Internal)		0.0%	0
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	1,399,000	71.8%	1,004,513
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend		18.3%	256,487
	General departmental expenses	Strategic Dept. Labor (Internal)		9.9%	138,000
Corporate Security	Provide Security Services for Company Assets	Assets	2,291,000	100.0%	2,291,000

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR	18,960,000	13.2%	2,500,000
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR		15.8%	3,000,000
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR		0.2%	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)		0.7%	125,000
	Transportation	Oper Maint Cap xBxTxR		21.1%	4,000,000
	Investment Recovery	Gross utility plant xBxTxR		1.1%	200,000
	Inergi Inspection Project	Inergi SMS (Internal)		6.3%	1,200,000
	Other departmental activities	Oper Maint Cap xBxTxR		0.5%	93,750
	Purchasing	Oper Maint Cap xB		26.6%	5,051,093
	Transportation	Oper Maint Cap xB		1.0%	189,416
	Asset disposal and Investment recovery	Gross utility plant xBxTxR		2.0%	378,832
	Strategic Sourcing Initiative	Oper Maint Cap xBxT		4.7%	883,941
	Support management of warehouse facilities	Total Assets xBxTxR		3.3%	631,387
	Other departmental activities	Inergi SMS (Internal)		3.6%	675,331
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)	1,075,000	100.0%	1,075,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	6,061,000	18.8%	1,139,673
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		7.4%	446,706
	Support Asset Management activities and projects	Asset Manager		12.8%	773,145
	Support Finance activities and projects	Finance Labor Costs (Internal)		12.4%	750,237
	Provide operational support for Transmission and Distribution activities	Asset Manager		1.5%	91,632
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		27.6%	1,672,284
	Support Inergi operations	Inergi IT (Internal)		11.9%	721,602
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		2.2%	131,721
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		5.5%	334,000

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	6,995,000	22.0%	1,541,475
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend		16.9%	1,178,775
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)		11.0%	770,738
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)		0.0%	0
	Revenue analysis and reporting	Total Revenue		6.3%	438,263
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend		14.7%	1,027,650
	Internal controls	Total Revenue_Assets Blend		5.8%	408,038
	Other departmental activities	Contr. Dept. Labor (Internal)		9.7%	680,063
	Actuarial consultants	FTEs		10.7%	750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend		0.0%	0
	General departmental expenses	Contr. Dept. Labor (Internal)		2.9%	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB	3,904,000	5.3%	208,800
	Insurance- Claims	Non-energy Rev_Assets Blend xB		79.7%	3,112,308
	Fiduciary insurance policy	FTEs		1.4%	55,091
	IT Costs	Total Capital		0.0%	0
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		13.5%	527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	1,663,000	38.3%	636,363
	Tax Planning	OperMaint Exp_Assets Blend		19.2%	318,903
	Support Debt issuance	Total Debt		0.8%	12,987
	Special Projects	OperMaint Exp_Assets Blend		1.6%	25,974
	Support regulatory filings	GC_Reg Dept. Labor (Internal)		1.1%	18,759
	Support Construction activities	Capital Expenditures		1.2%	20,202
	Other departmental activities	Tax Dept. Labor (Internal)		24.6%	409,812
	Tax Consultants	Tax Dept. Labor (Internal)		9.0%	150,000
	General departmental expenses	Tax Dept. Labor (Internal)		4.2%	70,000
Financial Strategy	Support Regulatory Activities	All Direct	2,084,000	8.6%	178,400
	Support Business Activities	All Direct		4.3%	89,200
	Special Projects	All Direct		8.6%	178,400
	Decision support for lines of business	All Direct		51.4%	1,070,400
	DSM	All Direct		8.6%	178,400
	Ontario Hydro Energy	All Direct		4.3%	89,200
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		14.4%	300,000

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	2,783,000	69.0%	1,919,130
	Purchasing	Oper Maint Cap		6.8%	189,210
	IMIT	Fin_IMIT Dept. Labor (Internal)		11.7%	324,360
	Human Resources	HR Dept. Labor (Internal)		1.0%	27,030
	Finance	Finance Labor Costs (Internal)		7.8%	216,240
	Customers	Total Revenue		1.0%	27,030
	General departmental expenses	IntAudit Dept. Labor (Internal)		2.9%	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct	7,709,000	29.4%	2,269,465
	Manage HO Relationship with OEB (incl. complaints)	All Direct		0.7%	52,235
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct		0.0%	0
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct		22.4%	1,727,872
	Provide Load Forecasts for HO and IMO	All Direct		10.2%	783,522
	Support Wholesale and Retail Settlement Process	All Direct		15.0%	1,159,475
	Section 92 Applications	All Direct		2.7%	209,627
	Code Reviews	All Direct		3.7%	282,480
	Other departmental activities	GC_Reg Dept. Labor (Internal)		5.0%	388,325
	All other costs	All Direct		10.8%	836,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct	12,229,000	100.0%	12,229,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	6,811,000	73.6%	5,011,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		24.5%	1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		1.9%	128,571
Telecom Services	Management of Telecoms Services	Telecom Services	16,962,230	18.7%	3,178,000
	Data backbone, assets and lines for all users	Workstations		28.5%	4,832,030
	Voice backbone, assets and lines for all users	Telephones		22.7%	3,849,400
	Repairs, adds, changes to telephones	Telephones		30.1%	5,102,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)	26,441,859	25.5%	6,732,405
	Support Finance Applications	Inergi Finance (Internal)		17.0%	4,488,270
	Support HR Applications	Inergi HR (Internal)		13.6%	3,590,616
	Support Passport Applications	ProgramProjectCosts		11.9%	3,141,789
	Support Market Ready Applications	Market Ready		27.0%	7,142,298
	Support Telecommunications Infrastructure	Telephones		5.1%	1,346,481

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)	25,583,140	13.6%	3,477,265
	Direct Assignments	All Direct		4.0%	1,014,964
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		82.4%	21,090,911
Customer Support Operations	Inbound calls / correspondence	All Direct	38,619,000	55.8%	21,549,402
	Bill Production	All Direct		24.6%	9,500,274
	Data Services- Timesheets for field personnel, Tx operations	All Direct		8.0%	3,089,520
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct		11.6%	4,479,804
Settlements	Wholesale and Retail Settlements	All Direct	3,000,000	100.0%	3,000,000
Finance	Accounts Payable processing	Invoices To Vendors	10,330,000	17.7%	1,828,262
	Accounts Receivable processing	Other Bills To Customers		13.2%	1,367,043
	Fixed Assets processing	Gross utility plant xB		6.3%	655,035
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		52.2%	5,387,497
	Pension support	FTEs		0.5%	53,193
	Inergi Corp. Finance	Inergi Total (Internal)		10.1%	1,038,970
HR - Pay Services	Payroll Services and Recordkeepping	FTEs	3,481,000	100.0%	3,481,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	326,000	92.3%	301,000
	General departmental expenses	Non-energy Rev_Assets Blend		7.7%	25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend	1,275,000	0.0%	0
	Audit Fee	Total Revenue_Assets Blend xBxTxR		54.7%	697,529
	General departmental expenses	Non-energy Rev_Assets Blend		45.3%	577,471

EXHIBIT B

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2007

Function or Service	Activities Performed	Cost Driver	2007 Budget for Function or Service	% Activity 2007 Budget	$ Activity 2007 Budget
(A)	(B)	(C)	(D)	(E)	(F)
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct	2,575,000	4.2%	107,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct		16.7%	430,800
	Develop and maintain relationships with major customers and customer groups	All Direct		16.7%	430,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct		16.7%	430,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct		8.4%	215,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct		16.7%	430,800
	Plan for management succession	All Direct		4.2%	107,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		16.3%	421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	671,000	88.8%	596,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		11.2%	75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	309,000	67.6%	209,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		32.4%	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	1,071,000	15.7%	168,250
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)		12.6%	134,600
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)		3.1%	33,650
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend		6.3%	67,300
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend		9.1%	97,585
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend		6.3%	67,300
	Support BOD	Non-energy Rev_Assets Blend		3.1%	33,650
	Ensure access to capital on reasonable terms	Total Capital		6.3%	67,300
	Other departmental activities	CFO Dept. Labor (Internal)		0.3%	3,365
	General departmental expenses	CFO Dept. Labor (Internal)		37.2%	398,000
Donations	Donations	Direct Holding Company	1,750,000	100.0%	1,750,000
Total CCFS			218,343,229		218,343,229

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
Human Resources	Administer Compensation & Benefits Programs Decision support Staffing & Leadership- Recruitment, Hiring, Succession Administer Pension Plan Administer Inergi HR Consulting support to LOBs and corporate functions Director			
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements Negotiate with Bargaining Units Participate in grievance and arbitration filings Participate in OLRB hearings Internal vacancy management			
Communications	Provide communications support for corporate safety program & activities Provide communications support for customer information requirements Provide Media Program for Community Info & Employee Contributions Provide Support for Shareholder and External Stakeholder Relationships Provide Support to CDM and Other Special Programs Provide other internal communications support Other departmental activities General departmental expenses			
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations		167,461	
	Develop working relationships with customers, regulators, shareholder, lenders	44,892	166,704	
	General departmental expenses			
Corporate Security	Provide Security Services for Company Assets	1,056,600	616,350	44,025

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2007 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
Human Resources	Administer Compensation & Benefits Programs	FTEs		418,760		418,760
	Decision support	FTEs		518,060		518,060
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		694,340		694,340
	Administer Pension Plan	FTEs		727,440		727,440
	Administer Inergi HR	Inergi HR (Internal)		209,380		209,380
	Consulting support to LOBs and corporate functions	FTEs		2,128,600		2,128,600
	Director	HR Dept. Labor (Internal)		372,420		372,420
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs		602,000		602,000
	Negotiate with Bargaining Units	FTEs		181,450		181,450
	Participate in grievance and arbitration filings	FTEs		485,150		485,150
	Participate in OLRB hearings	FTEs		120,400		120,400
	Internal vacancy management	FTEs				-
Communications	Provide communications support for corporate safety program & activities	FTEs	427,700			427,700
	Provide communications support for customer information requirements	Direct Dx	1,119,050			1,119,050
	Provide Media Program for Community Info & Employee Contributions	FTEs	1,570,400			1,570,400
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital	855,400			855,400
	Provide Support to CDM and Other Special Programs	Direct Dx	276,350			276,350
	Provide other internal communications support	FTEs	427,700			427,700
	Other departmental activities	Non-energy Rev_Assets Blend	155,000	695,400		850,400
	General departmental expenses	CorpComm Dept. Labor (Internal)				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	837,052			1,004,513
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend	44,892			256,487
	General departmental expenses	Strategic Dept. Labor (Internal)		138,000		138,000
Corporate Security	Provide Security Services for Company Assets	Assets		574,025		2,291,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)			
	Warehouse (Provincial lines)			
	Strategic Sourcing Initiative			
	Supervise Inergi- SMS			
	Transportation			
	Investment Recovery			
	Inergi Inspection Project			
	Other departmental activities			
	Purchasing			
	Transportation			
	Asset disposal and Investment recovery			
	Strategic Sourcing Initiative			
	Support management of warehouse facilities			
	Other departmental activities			
Corporate Services SVP	Manage all Corp Services Departments			
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications			
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements		74,451	
	Support Asset Management activities and projects			
	Support Finance activities and projects			
	Provide operational support for Transmission and Distribution activities			
	Manage IT capital projects and IT strategy			
	Support Inergi operations			
	Other departmental activities			
	General departmental expenses			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2007 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR			2,500,000	2,500,000
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR			3,000,000	3,000,000
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR			31,250	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)			125,000	125,000
	Transportation	Oper Maint Cap xBxTxR			4,000,000	4,000,000
	Investment Recovery	Gross utility plant xBxTxR			200,000	200,000
	Inergi Inspection Project	Inergi SMS (Internal)			1,200,000	1,200,000
	Other departmental activities	Oper Maint Cap xBxTxR			93,750	93,750
	Purchasing	Oper Maint Cap xB			5,051,093	5,051,093
	Transportation	Oper Maint Cap xB			189,416	189,416
	Asset disposal and Investment recovery	Gross utility plant xBxTxR			378,832	378,832
	Strategic Sourcing Initiative	Oper Maint Cap xBxT			883,941	883,941
	Support management of warehouse facilities	Total Assets xBxTxR			631,387	631,387
	Other departmental activities	Inergi SMS (Internal)			675,331	675,331
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)		1,075,000		1,075,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations		1,139,673		1,139,673
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		372,255		446,706
	Support Asset Management activities and projects	Asset Manager		773,145		773,145
	Support Finance activities and projects	Finance Labor Costs (Internal)		750,237		750,237
	Provide operational support for Transmission and Distribution activities	Asset Manager		91,632		91,632
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		1,672,284		1,672,284
	Support Inergi operations	Inergi IT (Internal)		721,602		721,602
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		131,721		131,721
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		334,000		334,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
Corporate Controller	Accting policies; External reports; External audit / review			57,428
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections			49,569
	Regulatory Finance Activities			18,135
	Manage Inergi- General and Inergi- Finance contract			
	Revenue analysis and reporting			12,090
	Monitor and support Financial systems and Corporate accounting			54,405
	Internal controls			24,180
	Other departmental activities			
	Actuarial consultants			
	Consultants- Bill 198 (Canadian SOX) compliance			
	General departmental expenses			
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management			
	Insurance- Claims			
	Fiduciary insurance policy			
	IT Costs			
	General departmental expenses			
Taxation	Compliance activities including tax filings and audits			111,111
	Tax Planning			12,987
	Support Debt issuance			
	Special Projects			1,443
	Support regulatory filings			2,886
	Support Construction activities			1,443
	Other departmental activities			
	Tax Consultants			
	General departmental expenses			
Financial Strategy	Support Regulatory Activities		178,400	
	Support Business Activities		89,200	
	Special Projects		178,400	
	Decision support for lines of business	610,128	406,752	53,520
	DSM		178,400	
	Ontario Hydro Energy			89,200
	General departmental expenses			

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2007 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	1,484,048			1,541,475
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend	1,129,206			1,178,775
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)	752,603			770,738
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)				-
	Revenue analysis and reporting	Total Revenue	426,173			438,263
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend	973,245			1,027,650
	Internal controls	Total Revenue_Assets Blend	383,858			408,038
	Other departmental activities	Contr. Dept. Labor (Internal)	317,363	362,700		680,063
	Actuarial consultants	FTEs		750,000		750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend				-
	General departmental expenses	Contr. Dept. Labor (Internal)		200,000		200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB		208,800		208,800
	Insurance- Claims	Non-energy Rev_Assets Blend xB		3,112,308		3,112,308
	Fiduciary insurance policy	FTEs		55,091		55,091
	IT Costs	Total Capital				-
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		527,801		527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	512,265	12,987		636,363
	Tax Planning	OperMaint Exp_Assets Blend	305,916			318,903
	Support Debt issuance	Total Debt		12,987		12,987
	Special Projects	OperMaint Exp_Assets Blend	24,531			25,974
	Support regulatory filings	GC_Reg Dept. Labor (Internal)	15,873			18,759
	Support Construction activities	Capital Expenditures	18,759			20,202
	Other departmental activities	Tax Dept. Labor (Internal)	409,812			409,812
	Tax Consultants	Tax Dept. Labor (Internal)		150,000		150,000
	General departmental expenses	Tax Dept. Labor (Internal)		70,000		70,000
Financial Strategy	Support Regulatory Activities	All Direct				178,400
	Support Business Activities	All Direct				89,200
	Special Projects	All Direct				178,400
	Decision support for lines of business	All Direct				1,070,400
	DSM	All Direct				178,400
	Ontario Hydro Energy	All Direct				89,200
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		300,000		300,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
Internal Audit & Risk Mgmt	Audits	648,720	378,420	162,180
	Purchasing			
	IMIT			
	Human Resources			
	Finance			
	Customers			
	General departmental expenses			
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,435,770	806,203	27,492
	Manage HO Relationship with OEB (incl. complaints)	687	51,548	
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates			
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	428,875	1,298,997	
	Provide Load Forecasts for HO and IMO	372,517	411,005	
	Support Wholesale and Retail Settlement Process	503,104	656,372	
	Section 92 Applications	209,627		
	Code Reviews	107,219	175,262	
	Other departmental activities	144,333	243,992	
	All other costs	275,283	560,717	
Regul. Affairs- OEB Cost	OEB Billed costs	6,736,526	5,492,474	
Law	Overall Assignment of Time			325,715
	Consultants and External Legal Counsel			
	General departmental expenses			
Telecom Services	Management of Telecoms Services			
	Data backbone, assets and lines for all users			
	Voice backbone, assets and lines for all users			
	Repairs, adds, changes to telephones			
ETS - Applications Support	Support CSO Applications			
	Support Finance Applications			
	Support HR Applications			
	Support Passport Applications			
	Support Market Ready Applications			
	Support Telecommunications Infrastructure			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2007 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	729,810			1,919,130
	Purchasing	Oper Maint Cap		189,210		189,210
	IMIT	Fin_IMIT Dept. Labor (Internal)		324,360		324,360
	Human Resources	HR Dept. Labor (Internal)		27,030		27,030
	Finance	Finance Labor Costs (Internal)		216,240		216,240
	Customers	Total Revenue		27,030		27,030
	General departmental expenses	IntAudit Dept. Labor (Internal)		80,000		80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct				2,269,465
	Manage HO Relationship with OEB (incl. complaints)	All Direct				52,235
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct				1,727,872
	Provide Load Forecasts for HO and IMO	All Direct				783,522
	Support Wholesale and Retail Settlement Process	All Direct				1,159,475
	Section 92 Applications	All Direct				209,627
	Code Reviews	All Direct				282,480
	Other departmental activities	GC_Reg Dept. Labor (Internal)				388,325
	All other costs	All Direct				836,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct				12,229,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	4,685,285			5,011,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		1,671,429		1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		128,571		128,571
Telecom Services	Management of Telecoms Services	Telecom Services		3,178,000		3,178,000
	Data backbone, assets and lines for all users	Workstations		4,832,030		4,832,030
	Voice backbone, assets and lines for all users	Telephones		3,849,400		3,849,400
	Repairs, adds, changes to telephones	Telephones		5,102,800		5,102,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)		6,732,405		6,732,405
	Support Finance Applications	Inergi Finance (Internal)		4,488,270		4,488,270
	Support HR Applications	Inergi HR (Internal)		3,590,616		3,590,616
	Support Passport Applications	ProgramProjectCosts		3,141,789		3,141,789
	Support Market Ready Applications	Market Ready		7,142,298		7,142,298
	Support Telecommunications Infrastructure	Telephones		1,346,481		1,346,481

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services			
	Direct Assignments		1,014,964	
	General Infrastructure Support			
Customer Support Operations	Inbound calls / correspondence		21,549,402	
	Bill Production		9,481,755	18,519
	Data Services- Timesheets for field personnel, Tx operations	463,428	2,626,092	
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,464,886	14,918
Settlements	Wholesale and Retail Settlements	450,000	2,550,000	
Finance	Accounts Payable processing			
	Accounts Receivable processing			
	Fixed Assets processing			
	Corporate accounting, Budgeting, Analysis			
	Pension support			
	Inergi Corp. Finance			
HR - Pay Services	Payroll Services and Recordkeepping			
Chair	Overall Assignment of Time			19,565
	General departmental expenses			
Board	Overall Assignment of Time			
	Audit Fee			
	General departmental expenses			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2007 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)		3,477,265		3,477,265
	Direct Assignments	All Direct				1,014,964
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		21,090,911		21,090,911
Customer Support Operations	Inbound calls / correspondence	All Direct				21,549,402
	Bill Production	All Direct				9,500,274
	Data Services- Timesheets for field personnel, Tx operations	All Direct				3,089,520
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct				4,479,804
Settlements	Wholesale and Retail Settlements	All Direct				3,000,000
Finance	Accounts Payable processing	Invoices To Vendors		1,828,262		1,828,262
	Accounts Receivable processing	Other Bills To Customers		1,367,043		1,367,043
	Fixed Assets processing	Gross utility plant xB		655,035		655,035
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		5,387,497		5,387,497
	Pension support	FTEs		53,193		53,193
	Inergi Corp. Finance	Inergi Total (Internal)		1,038,970		1,038,970
HR - Pay Services	Payroll Services and Recordkeepping	FTEs		3,481,000		3,481,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	281,435			301,000
	General departmental expenses	Non-energy Rev_Assets Blend		25,000		25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend				-
	Audit Fee	Total Revenue_Assets Blend xBxTxR		697,529		697,529
	General departmental expenses	Non-energy Rev_Assets Blend		577,471		577,471

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
President/CEO Office	Establish performance targets for safety, customer service, reliability	58,158	47,388	2,154
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	232,632	189,552	8,616
	Develop and maintain relationships with major customers and customer groups	232,632	189,552	8,616
	Develop and maintain relationships with regulators, shareholder, lenders	232,632	189,552	8,616
	Monitor, assess and remediate risks to operational and financial performance	116,316	94,776	4,308
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	232,632	189,552	8,616
	Plan for management succession	58,158	47,388	2,154
	General departmental expenses			
Corporate	Overall Assignment of Time			38,740
	General departmental expenses			
Corp. Secretariat	Overall Assignment of Time			13,585
	General departmental expenses			
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans			6,730
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder			5,048
	Ensure financial services are provided efficiently and reliably			6,730
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities			6,730
	Monitor performance against operational, financial and regulatory targets			30,285
	Ensure sufficient revenue for operating, financial and regulatory needs			6,730
	Support BOD			
	Ensure access to capital on reasonable terms			10,095
	Other departmental activities			
	General departmental expenses			
Donations	Donations			
TOTAL CCFS		14,650,867	54,765,965	1,268,562

EXHIBIT C

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2007

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2007 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct				107,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct				430,800
	Develop and maintain relationships with major customers and customer groups	All Direct				430,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct				430,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct				215,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct				430,800
	Plan for management succession	All Direct				107,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		421,000		421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	557,260			596,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		75,000		75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	195,415			209,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		100,000		100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	161,520			168,250
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)	129,553			134,600
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)	26,920			33,650
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend	60,570			67,300
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend	67,300			97,585
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend	60,570			67,300
	Support BOD	Non-energy Rev_Assets Blend		33,650		33,650
	Ensure access to capital on reasonable terms	Total Capital	57,205			67,300
	Other departmental activities	CFO Dept. Labor (Internal)		3,365		3,365
	General departmental expenses	CFO Dept. Labor (Internal)		398,000		398,000
Donations	Donations	Direct Holding Company		1,750,000		1,750,000
TOTAL CCFS			19,480,035	109,217,798	18,960,000	218,343,229

EXHIBIT D

HYDRO ONE COMMON CORPORATE COST MODEL
COST DRIVERS - 2007

DRIVER	DESCRIPTION	EXTERNAL DRIVER VALUES				EXTERNAL DRIVER %			
		Total	Trans-mission	Distrib-ution	Other	Total	Trans-mission	Distrib-ution	Other
Direct Dx	Place all costs of an activity into one business unit	1		1	-	100.0%	0.0%	100.0%	0.0%
Direct Tx	Place all costs of an activity into one business unit	1	1		-	100.0%	100.0%	0.0%	0.0%
Direct Shareholder	Place all costs of an activity into one business unit	1			1	100.0%	0.0%	0.0%	100.0%
All Direct	Placeholder when activity is 100% directly assigned	-			-	0.0%			
Physical									
Asset Manager	Results of Asset Manager time study, December 2004	100.0%	67.8%	32.2%	0.0%	100.0%	67.8%	32.2%	0.0%
Facilities SqFt	Square feet of facilities included in LBSS activities, 12/31/05 values (Shared)	130,858	71,201	59,072	585	100.0%	54.4%	45.1%	0.4%
FTEs	Full time equivalent employees, 12/31/05 values (Shared)	4,936	2,351	2,487	98	100.0%	47.6%	50.4%	2.0%
Invoices To Vendors	Self-explanatory, 2005 and 12/31/05 values (Shared)	90,260	40,694	44,114	5,452	100.0%	45.1%	48.9%	6.0%
ProgramProjectCosts	Program and Project Costs for Capital and OM spending on Transmission and Distribution for 2005	100.0%	47.6%	52.4%	0.0%	100.0%	47.6%	52.4%	0.0%
Other Bills To Customers	Bills to customers other than retail bills to customers, 2005 values	28,737	13,834	12,527	2,376	100.0%	48.1%	43.6%	8.3%
Telephones	Self-explanatory, 2005 and 12/31/05 values (Shared)	4,948	2,357	2,494	97	100.0%	47.6%	50.4%	2.0%
Workstations	Self-explanatory, 2005 and 12/31/05 values (Shared)	4,880	2,337	2,451	92	100.0%	47.9%	50.2%	1.9%

Each cost driver marked (Shared) included common portions in addition to portions due to business units. These common portions were allocated between Transmission and Distribution using ProgramProjectCosts cost driver or Asset Manager driver, as appropriate.

EXHIBIT D

HYDRO ONE COMMON CORPORATE COST MODEL
COST DRIVERS - 2007

DRIVER	DESCRIPTION	EXTERNAL DRIVER VALUES				EXTERNAL DRIVER %			
		Total	Trans-mission	Distrib-ution	Other	Total	Trans-mission	Distrib-ution	Other
Financial ($ millions)									
Capital expenditures	Budgeted amounts for 2007	752	389	333	31	100.0%	51.7%	44.3%	4.1%
Gross utility plant	Projected balances as of 12/31/07	16,059	9,742	5,770	547	100.0%	60.7%	35.9%	3.4%
Gross utility plant xB	Gross utility plant excl. Brampton	15,652	9,742	5,770	140	100.0%	62.2%	36.9%	0.9%
Gross utility plant xBxTxR	Gross utility plant excl. Brampton, Telecom, Remotes	15,512	9,742	5,770	-	100.0%	62.8%	37.2%	0.0%
Net utility plant	Projected balances as of 12/31/07	10,080	6,254	3,502	325	100.0%	62.0%	34.7%	3.2%
Non-energy revenue	Budgeted amounts for 2007	2,267	1,199	961	108	100.0%	52.9%	42.4%	4.8%
Oper Maint Cap	Budgeted amounts for 2007	1,364	649	632	82	100.0%	47.6%	46.4%	6.0%
Oper Maint Cap xB	Oper Maint Cap excl. Brampton	1,328	649	632	46	100.0%	48.9%	47.6%	3.5%
Oper Maint Cap xBxT	Oper Maint Cap excl. Brampton, Telecom	1,298	649	632	16	100.0%	50.0%	48.7%	1.2%
Oper Maint Cap xBxTxR	Oper Maint Cap excl. Brampton, Telecom, Remotes	1,282	649	632	-	100.0%	50.7%	49.3%	0.0%
Oper Maint Exp	Budgeted amounts for 2007	612	261	299	52	100.0%	42.6%	48.9%	8.4%
Total Assets	Projected balances as of 12/31/07	11,736	6,800	4,452	484	100.0%	57.9%	37.9%	4.1%
Total Assets xBxTxR	Total Assets excl. Brampton, Telecom, Remotes	11,252	6,800	4,452	-	100.0%	60.4%	39.6%	0.0%
Total Capital	Projected balances as of 12/31/07	10,177	6,214	3,563	400	100.0%	61.1%	35.0%	3.9%
Total Debt	Projected balances as of 12/31/07	6,042	3,654	2,109	279	100.0%	60.5%	34.9%	4.6%
Total Revenue	Budgeted amounts for 2007	4,412	1,199	2,824	389	100.0%	27.2%	64.0%	8.8%
Total Revenue xB	Budgeted amounts for 2007 excl. Brampton	4,085	1,199	2,824	62	100.0%	29.3%	69.1%	1.5%
Derived Financial									
Assets	Average Net utility Plant, Total Assets	100.0%	59.99%	36.33%	3.67%	100.0%	60.0%	36.3%	3.7%
Non-energy Rev_Assets Blend	50% Non-energy Revenue, 50% Assets	100.0%	56.43%	39.35%	4.21%	100.0%	56.4%	39.4%	4.2%
Non-energy Rev_Assets Blend xB	Non-energy Rev_Assets Blend excl. Brampton	97.4%	56.43%	39.35%	1.58%	100.0%	58.0%	40.4%	1.6%
Non-energy Rev_Assets Blend xBxTxR	Non-energy Rev_Assets Blend excl. Brampton, Telecom, Remotes	96.3%	59.99%	36.33%	-	100.0%	62.3%	37.7%	0.0%
OperMaint Exp_Assets Blend	50% Oper Maint Exp, 50% Assets	100.0%	52.77%	42.15%	5.08%	100.0%	52.8%	42.1%	5.1%
Non-energy Rev_Workstations Blend	50% Non-energy Revenue, 50% Workstations	100.0%	50.39%	46.29%	3.32%	100.0%	50.4%	46.3%	3.3%
Non-energy Rev_Workstations Blend xB	Non-energy Rev_Workstations Blend excl. Brampton	98.7%	50.39%	46.29%	1.98%	100.0%	51.1%	46.9%	2.0%
Total Revenue_Assets Blend	50% Total Revenue, 50% Assets	100.0%	43.58%	50.17%	6.24%	100.0%	43.6%	50.2%	6.2%
Total Revenue_Assets Blend xBxTxR	Total Revenue_Assets Blend excl. Brampton, Telecom, Remotes	93.8%	43.58%	50.17%	-	100.0%	46.5%	53.5%	0.0%

EXHIBIT D

HYDRO ONE COMMON CORPORATE COST MODEL
COST DRIVERS - 2007

DRIVER	DESCRIPTION	INTERNAL DRIVER VALUES				INTERNAL DRIVER %			
		Total	Trans-mission	Distrib-ution	Other	Total	Trans-mission	Distrib-ution	Other
CFO Dept. Labor (Internal)	Self-explanatory	669,635	333,398	262,471	73,765	100.0%	49.8%	39.2%	11.0%
Contr. Dept. Labor (Internal)	Self-explanatory	5,364,938	2,653,910	2,495,221	215,807	100.0%	49.5%	46.5%	4.0%
CorpComm Dept. Labor (Internal)	Self-explanatory	2,781,600	1,117,754	1,663,846	-	100.0%	40.2%	59.8%	0.0%
Corp Svcs Group (Internal)	Self-explanatory	25,426,000	12,353,649	12,852,062	220,289	100.0%	48.6%	50.5%	0.9%
Finance Labor Costs (Internal)	Self-explanatory	16,427,810	7,958,634	7,726,471	742,705	100.0%	48.4%	47.0%	4.5%
Fin_IMIT Dept. Labor (Internal)	Self-explanatory	5,595,279	2,684,803	2,819,494	90,981	100.0%	48.0%	50.4%	1.6%
Fin_Strat Dept. Labor (Internal)	Self-explanatory	1,784,000	610,128	1,031,152	142,720	100.0%	34.2%	57.8%	8.0%
Fin_Treas Dept. Labor (Internal)	Self-explanatory	240,000	144,062	91,055	4,883	100.0%	60.0%	37.9%	2.0%
GC_Corp Dept. Labor (Internal)	Self-explanatory	596,000	328,321	228,939	38,740	100.0%	55.1%	38.4%	6.5%
GC_Law Dept. Labor (Internal)	Self-explanatory	5,011,000	2,760,427	1,924,858	325,715	100.0%	55.1%	38.4%	6.5%
GC_Reg Dept. Labor (Internal)	Self-explanatory	6,484,676	3,057,798	3,399,386	27,492	100.0%	47.2%	52.4%	0.4%
GC_Secy Dept. Labor (Internal)	Self-explanatory	209,000	115,133	80,282	13,585	100.0%	55.1%	38.4%	6.5%
HR Dept. Labor (Internal)	Self-explanatory	4,054,440	1,930,917	2,043,026	80,497	100.0%	47.6%	50.4%	2.0%
Insurance Costs xB	Self-explanatory	4,751,237	2,866,631	1,785,007	99,599	100.0%	60.3%	37.6%	2.1%
IntAudit Dept. Labor (Internal)	Self-explanatory	2,703,000	1,480,346	1,031,090	191,564	100.0%	54.8%	38.1%	7.1%
IntAudit TD Audits (Internal)	Self-explanatory	0	0	0	-	100.0%	63.2%	36.8%	0.0%
Pres_CEO Dept. Labor (Internal)	Self-explanatory	2,154,000	1,163,160	947,760	43,080	100.0%	54.0%	44.0%	2.0%
Security Dept. Labor (Internal)	Self-explanatory	1,761,000	1,083,012	632,346	45,642	100.0%	61.5%	35.9%	2.6%
Strategic Dept. Labor (Internal)	Self-explanatory	1,261,000	564,506	696,494	-	100.0%	44.8%	55.2%	0.0%
Tax Dept. Labor (Internal)	Self-explanatory	1,033,188	500,863	401,197	131,128	100.0%	48.5%	38.8%	12.7%
Telecom Services	Self-explanatory	13,517,636	6,578,987	6,938,649	-	100.0%	48.7%	51.3%	0.0%
Inergi CSO (Internal)	Self-explanatory	34,139,196	463,428	33,657,249	18,519	100.0%	1.4%	98.6%	0.1%
Inergi Finance (Internal)	Self-explanatory; excl. Inergi Corp. Finance to avoid circularity	9,291,030	5,038,057	3,935,151	317,822	100.0%	54.2%	42.4%	3.4%
Inergi HR (Internal)	Self-explanatory	3,481,000	1,657,818	1,754,070	69,112	100.0%	47.6%	50.4%	2.0%
Inergi IT (Internal)	Self-explanatory	52,024,999	20,350,054	30,901,761	773,184	100.0%	39.1%	59.4%	1.5%
Inergi SMS (Internal)	Self-explanatory	7,134,669	3,624,295	3,316,850	193,524	100.0%	50.8%	46.5%	2.7%
Inergi Total (Internal)	Self-explanatory	106,070,894	31,133,651	73,565,082	1,372,161	100.0%	29.4%	69.4%	1.3%
Inergi Finance_Total Blend (Internal)	Self-explanatory	100.00%	41.79%	55.85%	2.36%	100.0%	41.8%	55.9%	2.4%

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2007 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Human Resources	Administer Compensation & Benefits Programs	199,433	211,012	8,314	418,760
	Decision support	246,725	261,050	10,286	518,060
	Staffing & Leadership- Recruitment, Hiring, Succession	330,678	349,877	13,786	694,340
	Administer Pension Plan	346,442	366,556	14,443	727,440
	Administer Inergi HR	99,717	105,506	4,157	209,380
	Consulting support to LOBs and corporate functions	1,013,740	1,072,598	42,262	2,128,600
	Director	177,364	187,662	7,394	372,420
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	286,701	303,347	11,952	602,000
	Negotiate with Bargaining Units	86,415	91,432	3,603	181,450
	Participate in grievance and arbitration filings	231,051	244,466	9,632	485,150
	Participate in OLRB hearings	57,340	60,669	2,390	120,400
	Internal vacancy management				-
Communications	Provide communications support for corporate safety program & activities	207,817	219,883		427,700
	Provide communications support for customer information requirements		1,119,050		1,119,050
	Provide Media Program for Community Info & Employee Contributions	763,049	807,351		1,570,400
	Provide Support for Shareholder and External Stakeholder Relationships	543,662	311,738		855,400
	Provide Support to CDM and Other Special Programs		276,350		276,350
	Provide other internal communications support	207,817	219,883		427,700
	Other departmental activities	454,730	366,369	29,301	850,400
	General departmental expenses				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	493,165	511,347		1,004,513
	Develop working relationships with customers, regulators, shareholder, lenders	71,340	185,147		256,487
	General departmental expenses	61,778	76,222		138,000
Corporate Security	Provide Security Services for Company Assets	1,408,961	822,660	59,379	2,291,000

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2007 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)			2,500,000	2,500,000
	Warehouse (Provincial lines)			3,000,000	3,000,000
	Strategic Sourcing Initiative			31,250	31,250
	Supervise Inergi- SMS			125,000	125,000
	Transportation			4,000,000	4,000,000
	Investment Recovery			200,000	200,000
	Inergi Inspection Project			1,200,000	1,200,000
	Other departmental activities			93,750	93,750
	Purchasing			5,051,093	5,051,093
	Transportation			189,416	189,416
	Asset disposal and Investment recovery			378,832	378,832
	Strategic Sourcing Initiative			883,941	883,941
	Support management of warehouse facilities			631,387	631,387
	Other departmental activities			675,331	675,331
Corporate Services SVP	Manage all Corp Services Departments	522,307	543,379	9,314	1,075,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	545,847	572,341	21,486	1,139,673
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	252,509	194,197		446,706
	Support Asset Management activities and projects	524,441	248,704		773,145
	Support Finance activities and projects	363,461	352,858	33,918	750,237
	Provide operational support for Transmission and Distribution activities	62,156	29,476		91,632
	Manage IT capital projects and IT strategy	654,129	993,302	24,853	1,672,284
	Support Inergi operations	282,261	428,616	10,724	721,602
	Other departmental activities	63,204	66,375	2,142	131,721
	General departmental expenses	160,264	168,305	5,431	334,000

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2007 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Corporate Controller	Accting policies; External reports; External audit / review	874,356	609,692	57,428	1,541,475
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	665,294	463,912	49,569	1,178,775
	Regulatory Finance Activities	356,395	396,208	18,135	770,738
	Manage Inergi- General and Inergi- Finance contract				-
	Revenue analysis and reporting	127,004	299,168	12,090	438,263
	Monitor and support Financial systems and Corporate accounting	452,422	520,823	54,405	1,027,650
	Internal controls	178,440	205,418	24,180	408,038
	Other departmental activities	342,991	322,482	14,590	680,063
	Actuarial consultants	357,186	377,924	14,891	750,000
	Consultants- Bill 198 (Canadian SOX) compliance				-
	General departmental expenses	98,935	93,020	8,045	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	125,978	78,445	4,377	208,800
	Insurance- Claims	1,803,913	1,257,876	50,519	3,112,308
	Fiduciary insurance policy	26,237	27,760	1,094	55,091
	IT Costs				-
	General departmental expenses	316,817	200,245	10,740	527,801
Taxation	Compliance activities including tax filings and audits	291,666	232,926	111,771	636,363
	Tax Planning	170,085	135,831	12,987	318,903
	Support Debt issuance	7,854	4,534	599	12,987
	Special Projects	13,639	10,892	1,443	25,974
	Support regulatory filings	7,517	8,356	2,886	18,759
	Support Construction activities	10,102	8,657	1,443	20,202
	Other departmental activities	227,546	182,266		409,812
	Tax Consultants	72,716	58,246	19,037	150,000
	General departmental expenses	33,934	27,182	8,884	70,000
Financial Strategy	Support Regulatory Activities		178,400		178,400
	Support Business Activities		89,200		89,200
	Special Projects		178,400		178,400
	Decision support for lines of business	610,128	406,752	53,520	1,070,400
	DSM		178,400		178,400
	Ontario Hydro Energy			89,200	89,200
	General departmental expenses	102,600	173,400	24,000	300,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2007 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Internal Audit & Risk Mgmt	Audits	1,109,653	647,297	162,180	1,919,130
	Purchasing	90,076	87,718	11,416	189,210
	IMIT	155,639	163,447	5,274	324,360
	Human Resources	12,873	13,620	537	27,030
	Finance	104,760	101,704	9,776	216,240
	Customers	7,346	17,303	2,382	27,030
	General departmental expenses	43,813	30,517	5,670	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,435,770	806,203	27,492	2,269,465
	Manage HO Relationship with OEB (incl. complaints)	687	51,548		52,235
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	428,875	1,298,997		1,727,872
	Provide Load Forecasts for HO and IMO	372,517	411,005		783,522
	Support Wholesale and Retail Settlement Process	503,104	656,372		1,159,475
	Section 92 Applications	209,627			209,627
	Code Reviews	107,219	175,262		282,480
	Other departmental activities	144,333	243,992		388,325
	All other costs	275,283	560,717		836,000
Regul. Affairs- OEB Cost	OEB Billed costs	6,736,526	5,492,474		12,229,000
Law	Overall Assignment of Time	2,760,427	1,924,858	325,715	5,011,000
	Consultants and External Legal Counsel	920,746	642,040	108,643	1,671,429
	General departmental expenses	70,827	49,388	8,357	128,571
Telecom Services	Management of Telecoms Services	1,516,807	1,599,729	61,464	3,178,000
	Data backbone, assets and lines for all users	2,314,303	2,426,632	91,096	4,832,030
	Voice backbone, assets and lines for all users	1,833,792	1,940,144	75,463	3,849,400
	Repairs, adds, changes to telephones	2,430,892	2,571,873	100,035	5,102,800
ETS - Applications Support	Support CSO Applications	91,390	6,637,363	3,652	6,732,405
	Support Finance Applications	2,433,762	1,900,975	153,532	4,488,270
	Support HR Applications	1,710,022	1,809,305	71,289	3,590,616
	Support Passport Applications	1,495,437	1,646,352		3,141,789
	Support Market Ready Applications	1,440,958	5,701,340		7,142,298
	Support Telecommunications Infrastructure	641,442	678,643	26,396	1,346,481

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2007 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	1,766,394	1,616,552	94,319	3,477,265
	Direct Assignments		1,014,964		1,014,964
	General Infrastructure Support	10,770,649	9,896,266	423,996	21,090,911
Customer Support Operations	Inbound calls / correspondence		21,549,402		21,549,402
	Bill Production		9,481,755	18,519	9,500,274
	Data Services- Timesheets for field personnel, Tx operations	463,428	2,626,092		3,089,520
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,464,886	14,918	4,479,804
Settlements	Wholesale and Retail Settlements	450,000	2,550,000		3,000,000
Finance	Accounts Payable processing	824,274	893,555	110,433	1,828,262
	Accounts Receivable processing	658,118	595,896	113,028	1,367,043
	Fixed Assets processing	407,705	241,475	5,855	655,035
	Corporate accounting, Budgeting, Analysis	3,122,627	2,177,421	87,450	5,387,497
	Pension support	25,333	26,804	1,056	53,193
	Inergi Corp. Finance	304,956	720,574	13,440	1,038,970
HR - Pay Services	Payroll Services and Recordkeepping	1,657,818	1,754,070	69,112	3,481,000
Chair	Overall Assignment of Time	165,813	115,622	19,565	301,000
	General departmental expenses	14,109	9,838	1,053	25,000
Board	Overall Assignment of Time				-
	Audit Fee	324,253	373,276		697,529
	General departmental expenses	325,892	227,246	24,332	577,471

EXHIBIT E

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2007

Function or Service	Activities Performed	Total Activity Cost to Business Unit			Total 2007 Activity Budget
		Transmission	Distribution	Other	
(A)	(B)	(D)	(C)	(E)	(F)
President/CEO Office	Establish performance targets for safety, customer service, reliability	58,158	47,388	2,154	107,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	232,632	189,552	8,616	430,800
	Develop and maintain relationships with major customers and customer groups	232,632	189,552	8,616	430,800
	Develop and maintain relationships with regulators, shareholder, lenders	232,632	189,552	8,616	430,800
	Monitor, assess and remediate risks to operational and financial performance	116,316	94,776	4,308	215,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	232,632	189,552	8,616	430,800
	Plan for management succession	58,158	47,388	2,154	107,700
	General departmental expenses	227,340	185,240	8,420	421,000
Corporate	Overall Assignment of Time	328,321	228,939	38,740	596,000
	General departmental expenses	41,316	28,809	4,875	75,000
Corp. Secretariat	Overall Assignment of Time	115,133	80,282	13,585	209,000
	General departmental expenses	55,087	38,413	6,500	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	95,163	66,357	6,730	168,250
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	65,735	63,817	5,048	134,600
	Ensure financial services are provided efficiently and reliably	13,659	13,261	6,730	33,650
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	28,157	32,413	6,730	67,300
	Monitor performance against operational, financial and regulatory targets	39,651	27,649	30,285	97,585
	Ensure sufficient revenue for operating, financial and regulatory needs	35,686	24,884	6,730	67,300
	Support BOD	18,990	13,242	1,418	33,650
	Ensure access to capital on reasonable terms	36,357	20,848	10,095	67,300
	Other departmental activities	1,675	1,319	371	3,365
	General departmental expenses	198,156	156,001	43,843	398,000
Donations	Donations			1,750,000	1,750,000
TOTAL CCFS		73,136,118	121,045,890	24,161,221	218,343,229

HYDRO ONE COMMON CORPORATE COST MODEL
SUMMARY OF CCFS COSTS DISTRIBUTED TO BUSINESS UNITS - 2007

Function or Service	Transmission	Distribution	Other	Total
Human Resources	2,414,099	2,554,261	100,641	5,069,000
Labour Relations	661,508	699,915	27,577	1,389,000
Communications	2,177,075	3,320,623	29,301	5,527,000
External Relations	626,284	772,716		1,399,000
Corporate Security	1,408,961	822,660	59,379	2,291,000
Suppy Management Services			18,960,000	18,960,000
Corporate Services SVP	522,307	543,379	9,314	1,075,000
Info Management & Info Technology	2,908,272	3,054,174	98,554	6,061,000
Corporate Controller	3,453,022	3,288,646	253,332	6,995,000
Treasury	2,272,945	1,564,326	66,729	3,904,000
Taxation	835,059	668,891	159,050	1,663,000
Financial Strategy	712,728	1,204,552	166,720	2,084,000
Internal Audit & Risk Mgmt	1,524,159	1,061,607	197,234	2,783,000
Regulatory Affairs	3,477,414	4,204,094	27,492	7,709,000
Regulatory Affairs- OEB Cost	6,736,526	5,492,474		12,229,000
Law	3,752,000	2,616,285	442,715	6,811,000
Telecom Services	8,095,795	8,538,378	328,058	16,962,230
ETS - Applications Support	7,813,012	18,373,979	254,869	26,441,859
ETS - Infrastructure	12,537,042	12,527,782	518,315	25,583,140
CSO	463,428	38,122,136	33,436	38,619,000
Settlements	450,000	2,550,000		3,000,000
Finance	5,343,013	4,655,725	331,262	10,330,000
HR	1,657,818	1,754,070	69,112	3,481,000
Chair	179,922	125,460	20,618	326,000
Board	650,145	600,522	24,332	1,275,000
President/CEO Office	1,390,500	1,133,000	51,500	2,575,000
Corporate	369,636	257,749	43,615	671,000
Corporate Secretariat	170,220	118,695	20,085	309,000
CFO Office	533,230	419,791	117,979	1,071,000
Donations			1,750,000	1,750,000
Total	73,136,118	121,045,890	24,161,221	218,343,229

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Human Resources	Administer Compensation & Benefits Programs	FTEs	5,252,000	8.2%	432,880
	Decision support	FTEs		10.1%	528,280
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		13.6%	712,920
	Administer Pension Plan	FTEs		14.2%	744,720
	Administer Inergi HR	Inergi HR (Internal)		4.1%	216,440
	Consulting support to LOBs and corporate functions	FTEs		42.4%	2,228,400
	Director	HR Dept. Labor (Internal)		7.4%	388,360
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs	1,471,000	42.4%	623,000
	Negotiate with Bargaining Units	FTEs		13.5%	198,850
	Participate in grievance and arbitration filings	FTEs		35.7%	524,550
	Participate in OLRB hearings	FTEs		8.5%	124,600
	Internal vacancy management	FTEs		0.0%	0
Communications	Provide communications support for corporate safety program & activities	FTEs	5,641,000	7.8%	439,100
	Provide communications support for customer information requirements	Direct Dx		20.1%	1,136,150
	Provide Media Program for Community Info & Employee Contributions	FTEs		28.2%	1,593,200
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital		15.6%	878,200
	Provide Support to CDM and Other Special Programs	Direct Dx		5.0%	282,050
	Provide other internal communications support	FTEs		7.8%	439,100
	Other departmental activities	Non-energy Rev_Assets Blend		15.5%	873,200
	General departmental expenses	CorpComm Dept. Labor (Internal)		0.0%	0
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	1,440,000	72.0%	1,037,173
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend		18.4%	264,827
	General departmental expenses	Strategic Dept. Labor (Internal)		9.6%	138,000
Corporate Security	Provide Security Services for Company Assets	Assets	2,350,000	100.0%	2,350,000

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR	19,303,000	13.2%	2,550,598
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR		15.7%	3,036,141
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR		0.2%	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)		0.6%	125,000
	Transportation	Oper Maint Cap xBxTxR		21.9%	4,229,497
	Investment Recovery	Gross utility plant xBxTxR		1.1%	209,758
	Inergi Inspection Project	Inergi SMS (Internal)		6.6%	1,269,391
	Other departmental activities	Oper Maint Cap xBxTxR		0.5%	97,364
	Purchasing	Oper Maint Cap xB		26.0%	5,014,875
	Transportation	Oper Maint Cap xB		1.0%	188,058
	Asset disposal and Investment recovery	Gross utility plant xBxTxR		1.9%	376,116
	Strategic Sourcing Initiative	Oper Maint Cap xBxT		4.5%	877,603
	Support management of warehouse facilities	Total Assets xBxTxR		3.2%	626,859
	Other departmental activities	Inergi SMS (Internal)		3.5%	670,489
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)	1,099,000	100.0%	1,099,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	6,260,000	18.8%	1,179,274
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		7.4%	462,228
	Support Asset Management activities and projects	Asset Manager		12.8%	800,010
	Support Finance activities and projects	Finance Labor Costs (Internal)		12.4%	776,306
	Provide operational support for Transmission and Distribution activities	Asset Manager		1.5%	94,816
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		27.6%	1,730,392
	Support Inergi operations	Inergi IT (Internal)		11.9%	746,676
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		2.2%	136,298
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		5.3%	334,000

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	7,010,000	22.0%	1,545,300
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend		16.9%	1,181,700
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)		11.0%	772,650
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)		0.0%	0
	Revenue analysis and reporting	Total Revenue		6.3%	439,350
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend		14.7%	1,030,200
	Internal controls	Total Revenue_Assets Blend		5.8%	409,050
	Other departmental activities	Contr. Dept. Labor (Internal)		9.7%	681,750
	Actuarial consultants	FTEs		10.7%	750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend		0.0%	0
	General departmental expenses	Contr. Dept. Labor (Internal)		2.9%	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB	3,913,000	5.5%	216,630
	Insurance- Claims	Non-energy Rev_Assets Blend xB		79.6%	3,113,478
	Fiduciary insurance policy	FTEs		1.4%	55,091
	IT Costs	Total Capital		0.0%	0
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		13.5%	527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	1,713,000	38.4%	658,413
	Tax Planning	OperMaint Exp_Assets Blend		19.3%	329,953
	Support Debt issuance	Total Debt		0.8%	13,437
	Special Projects	OperMaint Exp_Assets Blend		1.6%	26,874
	Support regulatory filings	GC_Reg Dept. Labor (Internal)		1.1%	19,409
	Support Construction activities	Capital Expenditures		1.2%	20,902
	Other departmental activities	Tax Dept. Labor (Internal)		24.8%	424,012
	Tax Consultants	Tax Dept. Labor (Internal)		8.8%	150,000
	General departmental expenses	Tax Dept. Labor (Internal)		4.1%	70,000
Financial Strategy	Support Regulatory Activities	All Direct	1,896,000	9.7%	184,600
	Support Business Activities	All Direct		4.9%	92,300
	Special Projects	All Direct		9.7%	184,600
	Decision support for lines of business	All Direct		58.4%	1,107,600
	DSM	All Direct		9.7%	184,600
	Ontario Hydro Energy	All Direct		4.9%	92,300
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		2.6%	50,000

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	2,878,000	69.0%	1,986,580
	Purchasing	Oper Maint Cap		6.8%	195,860
	IMIT	Fin_IMIT Dept. Labor (Internal)		11.7%	335,760
	Human Resources	HR Dept. Labor (Internal)		1.0%	27,980
	Finance	Finance Labor Costs (Internal)		7.8%	223,840
	Customers	Total Revenue		1.0%	27,980
	General departmental expenses	IntAudit Dept. Labor (Internal)		2.8%	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct	7,996,000	28.5%	2,277,059
	Manage HO Relationship with OEB (incl. complaints)	All Direct		0.7%	52,410
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct		0.0%	0
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct		21.7%	1,733,654
	Provide Load Forecasts for HO and IMO	All Direct		9.8%	786,144
	Support Wholesale and Retail Settlement Process	All Direct		14.5%	1,163,355
	Section 92 Applications	All Direct		2.6%	210,328
	Code Reviews	All Direct		3.5%	283,426
	Other departmental activities	GC_Reg Dept. Labor (Internal)		4.9%	389,624
	All other costs	All Direct		13.8%	1,100,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct	11,945,000	100.0%	11,945,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	6,985,000	74.2%	5,185,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		23.9%	1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		1.8%	128,571
Telecom Services	Management of Telecoms Services	Telecom Services	17,068,830	21.5%	3,675,000
	Data backbone, assets and lines for all users	Workstations		28.3%	4,832,030
	Voice backbone, assets and lines for all users	Telephones		22.6%	3,854,000
	Repairs, adds, changes to telephones	Telephones		27.6%	4,707,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)	26,472,864	25.5%	6,740,299
	Support Finance Applications	Inergi Finance (Internal)		17.0%	4,493,533
	Support HR Applications	Inergi HR (Internal)		13.6%	3,594,826
	Support Passport Applications	ProgramProjectCosts		11.9%	3,145,473
	Support Market Ready Applications	Market Ready		27.0%	7,150,673
	Support Telecommunications Infrastructure	Telephones		5.1%	1,348,060

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)	25,613,137	13.6%	3,481,342
	Direct Assignments	All Direct		4.0%	1,016,154
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		82.4%	21,115,641
Customer Support Operations	Inbound calls / correspondence	All Direct	38,190,000	55.8%	21,310,020
	Bill Production	All Direct		24.6%	9,394,740
	Data Services- Timesheets for field personnel, Tx operations	All Direct		8.0%	3,055,200
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct		11.6%	4,430,040
Settlements	Wholesale and Retail Settlements	All Direct	3,000,000	100.0%	3,000,000
Finance	Accounts Payable processing	Invoices To Vendors	9,825,000	17.7%	1,738,884
	Accounts Receivable processing	Other Bills To Customers		13.2%	1,300,213
	Fixed Assets processing	Gross utility plant xB		6.3%	623,012
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		52.2%	5,124,120
	Pension support	FTEs		0.5%	50,592
	Inergi Corp. Finance	Inergi Total (Internal)		10.1%	988,178
HR - Pay Services	Payroll Services and Recordkeepping	FTEs	3,516,000	100.0%	3,516,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	338,000	92.6%	313,000
	General departmental expenses	Non-energy Rev_Assets Blend		7.4%	25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend	1,275,000	0.0%	0
	Audit Fee	Total Revenue_Assets Blend xBxTxR		54.7%	697,529
	General departmental expenses	Non-energy Rev_Assets Blend		45.3%	577,471

HYDRO ONE COMMON CORPORATE COST MODEL
BUDGETED COSTS AND ACTIVITIES FOR COMMON CORPORATE FUNCTIONS AND SERVICES- 2008

Function or Service	Activities Performed	Cost Driver	2008 Budget for Function or Service	% Activity 2008 Budget	$ Activity 2008 Budget
(A)	(B)	(C)	(D)	(E)	(F)
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct	2,635,000	4.2%	110,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct		16.8%	442,800
	Develop and maintain relationships with major customers and customer groups	All Direct		16.8%	442,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct		16.8%	442,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct		8.4%	221,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct		16.8%	442,800
	Plan for management succession	All Direct		4.2%	110,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		16.0%	421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	689,000	89.1%	614,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		10.9%	75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	317,000	68.5%	217,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		31.5%	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	1,079,000	16.2%	174,750
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)		13.0%	139,800
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)		3.2%	34,950
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend		6.5%	69,900
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend		9.4%	101,355
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend		6.5%	69,900
	Support BOD	Non-energy Rev_Assets Blend		3.2%	34,950
	Ensure access to capital on reasonable terms	Total Capital		6.5%	69,900
	Other departmental activities	CFO Dept. Labor (Internal)		0.3%	3,495
	General departmental expenses	CFO Dept. Labor (Internal)		35.2%	380,000
Donations	Donations	Direct Holding Company	2,000,000	100.0%	2,000,000
Total CCFS			219,170,831		219,170,831

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
Human Resources	Administer Compensation & Benefits Programs Decision support Staffing & Leadership- Recruitment, Hiring, Succession Administer Pension Plan Administer Inergi HR Consulting support to LOBs and corporate functions Director			
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements Negotiate with Bargaining Units Participate in grievance and arbitration filings Participate in OLRB hearings Internal vacancy management			
Communications	Provide communications support for corporate safety program & activities Provide communications support for customer information requirements Provide Media Program for Community Info & Employee Contributions Provide Support for Shareholder and External Stakeholder Relationships Provide Support to CDM and Other Special Programs Provide other internal communications support Other departmental activities General departmental expenses			
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations		172,906	
	Develop working relationships with customers, regulators, shareholder, lenders	46,351	172,124	
	General departmental expenses			
Corporate Security	Provide Security Services for Company Assets	1,083,811	632,223	45,159

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Cost Driver	Allocation			Total 2008 Activity Budget
			Allocated to T&D	Allocated to T&D, Others	Materials Surcharge	
(A)	(B)	(F)	(G)	(H)	(I)	(J)
Human Resources	Administer Compensation & Benefits Programs	FTEs		432,880		432,880
	Decision support	FTEs		528,280		528,280
	Staffing & Leadership- Recruitment, Hiring, Succession	FTEs		712,920		712,920
	Administer Pension Plan	FTEs		744,720		744,720
	Administer Inergi HR	Inergi HR (Internal)		216,440		216,440
	Consulting support to LOBs and corporate functions	FTEs		2,228,400		2,228,400
	Director	HR Dept. Labor (Internal)		388,360		388,360
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs		623,000		623,000
	Negotiate with Bargaining Units	FTEs		198,850		198,850
	Participate in grievance and arbitration filings	FTEs		524,550		524,550
	Participate in OLRB hearings	FTEs		124,600		124,600
	Internal vacancy management	FTEs				-
Communications	Provide communications support for corporate safety program & activities	FTEs	439,100			439,100
	Provide communications support for customer information requirements	Direct Dx	1,136,150			1,136,150
	Provide Media Program for Community Info & Employee Contributions	FTEs	1,593,200			1,593,200
	Provide Support for Shareholder and External Stakeholder Relationships	Total Capital	878,200			878,200
	Provide Support to CDM and Other Special Programs	Direct Dx	282,050			282,050
	Provide other internal communications support	FTEs	439,100			439,100
	Other departmental activities	Non-energy Rev_Assets Blend	159,156	714,044		873,200
	General departmental expenses	CorpComm Dept. Labor (Internal)				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	864,268			1,037,173
	Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend	46,351			264,827
	General departmental expenses	Strategic Dept. Labor (Internal)		138,000		138,000
Corporate Security	Provide Security Services for Company Assets	Assets		588,808		2,350,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)			
	Warehouse (Provincial lines)			
	Strategic Sourcing Initiative			
	Supervise Inergi- SMS			
	Transportation			
	Investment Recovery			
	Inergi Inspection Project			
	Other departmental activities			
	Purchasing			
	Transportation			
	Asset disposal and Investment recovery			
	Strategic Sourcing Initiative			
	Support management of warehouse facilities			
	Other departmental activities			
Corporate Services SVP	Manage all Corp Services Departments			
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications			
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements		77,038	
	Support Asset Management activities and projects			
	Support Finance activities and projects			
	Provide operational support for Transmission and Distribution activities			
	Manage IT capital projects and IT strategy			
	Support Inergi operations			
	Other departmental activities			
	General departmental expenses			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2008 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR			2,550,598	2,550,598
	Warehouse (Provincial lines)	Oper Maint Cap xBxTxR			3,036,141	3,036,141
	Strategic Sourcing Initiative	Oper Maint Cap xBxTxR			31,250	31,250
	Supervise Inergi- SMS	Inergi SMS (Internal)			125,000	125,000
	Transportation	Oper Maint Cap xBxTxR			4,229,497	4,229,497
	Investment Recovery	Gross utility plant xBxTxR			209,758	209,758
	Inergi Inspection Project	Inergi SMS (Internal)			1,269,391	1,269,391
	Other departmental activities	Oper Maint Cap xBxTxR			97,364	97,364
	Purchasing	Oper Maint Cap xB			5,014,875	5,014,875
	Transportation	Oper Maint Cap xB			188,058	188,058
	Asset disposal and Investment recovery	Gross utility plant xBxTxR			376,116	376,116
	Strategic Sourcing Initiative	Oper Maint Cap xBxT			877,603	877,603
	Support management of warehouse facilities	Total Assets xBxTxR			626,859	626,859
	Other departmental activities	Inergi SMS (Internal)			670,489	670,489
Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)		1,099,000		1,099,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations		1,179,274		1,179,274
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager		385,190		462,228
	Support Asset Management activities and projects	Asset Manager		800,010		800,010
	Support Finance activities and projects	Finance Labor Costs (Internal)		776,306		776,306
	Provide operational support for Transmission and Distribution activities	Asset Manager		94,816		94,816
	Manage IT capital projects and IT strategy	Inergi IT (Internal)		1,730,392		1,730,392
	Support Inergi operations	Inergi IT (Internal)		746,676		746,676
	Other departmental activities	Fin_IMIT Dept. Labor (Internal)		136,298		136,298
	General departmental expenses	Fin_IMIT Dept. Labor (Internal)		334,000		334,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
Corporate Controller	Accting policies; External reports; External audit / review			57,570
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections			49,692
	Regulatory Finance Activities			18,180
	Manage Inergi- General and Inergi- Finance contract			
	Revenue analysis and reporting			12,120
	Monitor and support Financial systems and Corporate accounting			54,540
	Internal controls			24,240
	Other departmental activities			
	Actuarial consultants			
	Consultants- Bill 198 (Canadian SOX) compliance			
	General departmental expenses			
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management			
	Insurance- Claims			
	Fiduciary insurance policy			
	IT Costs			
	General departmental expenses			
Taxation	Compliance activities including tax filings and audits			114,961
	Tax Planning			13,437
	Support Debt issuance			
	Special Projects			1,493
	Support regulatory filings			2,986
	Support Construction activities			1,493
	Other departmental activities			
	Tax Consultants			
	General departmental expenses			
Financial Strategy	Support Regulatory Activities		184,600	
	Support Business Activities		92,300	
	Special Projects		184,600	
	Decision support for lines of business	631,332	420,888	55,380
	DSM		184,600	
	Ontario Hydro Energy			92,300
	General departmental expenses			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

		Allocation				
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2008 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	1,487,730			1,545,300
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend	1,132,008			1,181,700
	Regulatory Finance Activities	GC_Reg Dept. Labor (Internal)	754,470			772,650
	Manage Inergi- General and Inergi- Finance contract	Inergi Finance_Total Blend (Internal)				-
	Revenue analysis and reporting	Total Revenue	427,230			439,350
	Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend	975,660			1,030,200
	Internal controls	Total Revenue_Assets Blend	384,810			409,050
	Other departmental activities	Contr. Dept. Labor (Internal)	318,150	363,600		681,750
	Actuarial consultants	FTEs		750,000		750,000
	Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend				-
	General departmental expenses	Contr. Dept. Labor (Internal)		200,000		200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB		216,630		216,630
	Insurance- Claims	Non-energy Rev_Assets Blend xB		3,113,478		3,113,478
	Fiduciary insurance policy	FTEs		55,091		55,091
	IT Costs	Total Capital				-
	General departmental expenses	Fin_Treas Dept. Labor (Internal)		527,801		527,801
Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	530,015	13,437		658,413
	Tax Planning	OperMaint Exp_Assets Blend	316,516			329,953
	Support Debt issuance	Total Debt		13,437		13,437
	Special Projects	OperMaint Exp_Assets Blend	25,381			26,874
	Support regulatory filings	GC_Reg Dept. Labor (Internal)	16,423			19,409
	Support Construction activities	Capital Expenditures	19,409			20,902
	Other departmental activities	Tax Dept. Labor (Internal)	424,012			424,012
	Tax Consultants	Tax Dept. Labor (Internal)		150,000		150,000
	General departmental expenses	Tax Dept. Labor (Internal)		70,000		70,000
Financial Strategy	Support Regulatory Activities	All Direct				184,600
	Support Business Activities	All Direct				92,300
	Special Projects	All Direct				184,600
	Decision support for lines of business	All Direct				1,107,600
	DSM	All Direct				184,600
	Ontario Hydro Energy	All Direct				92,300
	General departmental expenses	Fin_Strat Dept. Labor (Internal)		50,000		50,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

		Direct Assignment		
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**
(A)	**(B)**	**(D)**	**(C)**	**(E)**
Internal Audit & Risk Mgmt	Audits	671,520	391,720	167,880
	Purchasing			
	IMIT			
	Human Resources			
	Finance			
	Customers			
	General departmental expenses			
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,440,574	808,901	27,584
	Manage HO Relationship with OEB (incl. complaints)	690	51,720	
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates			
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	430,310	1,303,344	
	Provide Load Forecasts for HO and IMO	373,763	412,381	
	Support Wholesale and Retail Settlement Process	504,787	658,568	
	Section 92 Applications	210,328		
	Code Reviews	107,578	175,848	
	Other departmental activities	144,816	244,808	
	All other costs	362,214	737,786	
Regul. Affairs- OEB Cost	OEB Billed costs	6,580,081	5,364,919	
Law	Overall Assignment of Time			337,025
	Consultants and External Legal Counsel			
	General departmental expenses			
Telecom Services	Management of Telecoms Services			
	Data backbone, assets and lines for all users			
	Voice backbone, assets and lines for all users			
	Repairs, adds, changes to telephones			
ETS - Applications Support	Support CSO Applications			
	Support Finance Applications			
	Support HR Applications			
	Support Passport Applications			
	Support Market Ready Applications			
	Support Telecommunications Infrastructure			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2008 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	755,460			1,986,580
	Purchasing	Oper Maint Cap		195,860		195,860
	IMIT	Fin_IMIT Dept. Labor (Internal)		335,760		335,760
	Human Resources	HR Dept. Labor (Internal)		27,980		27,980
	Finance	Finance Labor Costs (Internal)		223,840		223,840
	Customers	Total Revenue		27,980		27,980
	General departmental expenses	IntAudit Dept. Labor (Internal)		80,000		80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	All Direct				2,277,059
	Manage HO Relationship with OEB (incl. complaints)	All Direct				52,410
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates	All Direct				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	All Direct				1,733,654
	Provide Load Forecasts for HO and IMO	All Direct				786,144
	Support Wholesale and Retail Settlement Process	All Direct				1,163,355
	Section 92 Applications	All Direct				210,328
	Code Reviews	All Direct				283,426
	Other departmental activities	GC_Reg Dept. Labor (Internal)				389,624
	All other costs	All Direct				1,100,000
Regul. Affairs- OEB Cost	OEB Billed costs	All Direct				11,945,000
Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	4,847,975			5,185,000
	Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)		1,671,429		1,671,429
	General departmental expenses	GC_Law Dept. Labor (Internal)		128,571		128,571
Telecom Services	Management of Telecoms Services	Telecom Services		3,675,000		3,675,000
	Data backbone, assets and lines for all users	Workstations		4,832,030		4,832,030
	Voice backbone, assets and lines for all users	Telephones		3,854,000		3,854,000
	Repairs, adds, changes to telephones	Telephones		4,707,800		4,707,800
ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)		6,740,299		6,740,299
	Support Finance Applications	Inergi Finance (Internal)		4,493,533		4,493,533
	Support HR Applications	Inergi HR (Internal)		3,594,826		3,594,826
	Support Passport Applications	ProgramProjectCosts		3,145,473		3,145,473
	Support Market Ready Applications	Market Ready		7,150,673		7,150,673
	Support Telecommunications Infrastructure	Telephones		1,348,060		1,348,060

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services			
	Direct Assignments		1,016,154	
	General Infrastructure Support			
Customer Support Operations	Inbound calls / correspondence		21,310,020	
	Bill Production		9,376,427	18,313
	Data Services- Timesheets for field personnel, Tx operations	458,280	2,596,920	
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,415,288	14,752
Settlements	Wholesale and Retail Settlements	450,000	2,550,000	
Finance	Accounts Payable processing			
	Accounts Receivable processing			
	Fixed Assets processing			
	Corporate accounting, Budgeting, Analysis			
	Pension support			
	Inergi Corp. Finance			
HR - Pay Services	Payroll Services and Recordkeepping			
Chair	Overall Assignment of Time			20,345
	General departmental expenses			
Board	Overall Assignment of Time			
	Audit Fee			
	General departmental expenses			

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

			Allocation			
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2008 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)		3,481,342		3,481,342
	Direct Assignments	All Direct				1,016,154
	General Infrastructure Support	Non-energy Rev_Workstations Blend xB		21,115,641		21,115,641
Customer Support Operations	Inbound calls / correspondence	All Direct				21,310,020
	Bill Production	All Direct				9,394,740
	Data Services- Timesheets for field personnel, Tx operations	All Direct				3,055,200
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct				4,430,040
Settlements	Wholesale and Retail Settlements	All Direct				3,000,000
Finance	Accounts Payable processing	Invoices To Vendors		1,738,884		1,738,884
	Accounts Receivable processing	Other Bills To Customers		1,300,213		1,300,213
	Fixed Assets processing	Gross utility plant xB		623,012		623,012
	Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB		5,124,120		5,124,120
	Pension support	FTEs		50,592		50,592
	Inergi Corp. Finance	Inergi Total (Internal)		988,178		988,178
HR - Pay Services	Payroll Services and Recordkeepping	FTEs		3,516,000		3,516,000
Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	292,655			313,000
	General departmental expenses	Non-energy Rev_Assets Blend		25,000		25,000
Board	Overall Assignment of Time	Non-energy Rev_Assets Blend				-
	Audit Fee	Total Revenue_Assets Blend xBxTxR		697,529		697,529
	General departmental expenses	Non-energy Rev_Assets Blend		577,471		577,471

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

Function or Service	Activities Performed	Direct Assignment		
		Transmission	Distribution	Other
(A)	(B)	(D)	(C)	(E)
President/CEO Office	Establish performance targets for safety, customer service, reliability	59,778	48,708	2,214
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	239,112	194,832	8,856
	Develop and maintain relationships with major customers and customer groups	239,112	194,832	8,856
	Develop and maintain relationships with regulators, shareholder, lenders	239,112	194,832	8,856
	Monitor, assess and remediate risks to operational and financial performance	119,556	97,416	4,428
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	239,112	194,832	8,856
	Plan for management succession	59,778	48,708	2,214
	General departmental expenses			
Corporate	Overall Assignment of Time			39,910
	General departmental expenses			
Corp. Secretariat	Overall Assignment of Time			14,105
	General departmental expenses			
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans			6,990
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder			5,243
	Ensure financial services are provided efficiently and reliably			6,990
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities			6,990
	Monitor performance against operational, financial and regulatory targets			31,455
	Ensure sufficient revenue for operating, financial and regulatory needs			6,990
	Support BOD			
	Ensure access to capital on reasonable terms			10,485
	Other departmental activities			
	General departmental expenses			
Donations	Donations			
TOTAL CCFS		14,691,995	54,510,242	1,302,887

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COST ASSIGNMENTS TO BUSINESS UNITS - 2008

		Allocation				
Function or Service	**Activities Performed**	**Cost Driver**	**Allocated to T&D**	**Allocated to T&D, Others**	**Materials Surcharge**	**Total 2008 Activity Budget**
(A)	**(B)**	**(F)**	**(G)**	**(H)**	**(I)**	**(J)**
President/CEO Office	Establish performance targets for safety, customer service, reliability	All Direct				110,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct				442,800
	Develop and maintain relationships with major customers and customer groups	All Direct				442,800
	Develop and maintain relationships with regulators, shareholder, lenders	All Direct				442,800
	Monitor, assess and remediate risks to operational and financial performance	All Direct				221,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct				442,800
	Plan for management succession	All Direct				110,700
	General departmental expenses	Pres_CEO Dept. Labor (Internal)		421,000		421,000
Corporate	Overall Assignment of Time	Non-energy Rev_Assets Blend	574,090			614,000
	General departmental expenses	GC_Corp Dept. Labor (Internal)		75,000		75,000
Corp. Secretariat	Overall Assignment of Time	Non-energy Rev_Assets Blend	202,895			217,000
	General departmental expenses	GC_Secy Dept. Labor (Internal)		100,000		100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	Non-energy Rev_Assets Blend	167,760			174,750
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	Finance Labor Costs (Internal)	134,558			139,800
	Ensure financial services are provided efficiently and reliably	Finance Labor Costs (Internal)	27,960			34,950
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	Total Revenue_Assets Blend	62,910			69,900
	Monitor performance against operational, financial and regulatory targets	Non-energy Rev_Assets Blend	69,900			101,355
	Ensure sufficient revenue for operating, financial and regulatory needs	Non-energy Rev_Assets Blend	62,910			69,900
	Support BOD	Non-energy Rev_Assets Blend		34,950		34,950
	Ensure access to capital on reasonable terms	Total Capital	59,415			69,900
	Other departmental activities	CFO Dept. Labor (Internal)		3,495		3,495
	General departmental expenses	CFO Dept. Labor (Internal)		380,000		380,000
Donations	Donations	Direct Holding Company		2,000,000		2,000,000
TOTAL CCFS			19,907,876	109,454,831	19,303,000	219,170,831

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2008 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Human Resources	Administer Compensation & Benefits Programs	206,158	218,128	8,594	432,880
	Decision support	251,592	266,199	10,489	528,280
	Staffing & Leadership- Recruitment, Hiring, Succession	339,526	359,239	14,154	712,920
	Administer Pension Plan	354,671	375,263	14,786	744,720
	Administer Inergi HR	103,079	109,064	4,297	216,440
	Consulting support to LOBs and corporate functions	1,061,270	1,122,887	44,243	2,228,400
	Director	184,955	195,694	7,711	388,360
Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	296,702	313,929	12,369	623,000
	Negotiate with Bargaining Units	94,702	100,200	3,948	198,850
	Participate in grievance and arbitration filings	249,816	264,320	10,414	524,550
	Participate in OLRB hearings	59,340	62,786	2,474	124,600
	Internal vacancy management				-
Communications	Provide communications support for corporate safety program & activities	213,356	225,744		439,100
	Provide communications support for customer information requirements		1,136,150		1,136,150
	Provide Media Program for Community Info & Employee Contributions	774,127	819,073		1,593,200
	Provide Support for Shareholder and External Stakeholder Relationships	558,153	320,047		878,200
	Provide Support to CDM and Other Special Programs		282,050		282,050
	Provide other internal communications support	213,356	225,744		439,100
	Other departmental activities	467,597	375,341	30,262	873,200
	General departmental expenses				-
External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	509,200	527,973		1,037,173
	Develop working relationships with customers, regulators, shareholder, lenders	73,660	191,167		264,827
	General departmental expenses	61,778	76,222		138,000
Corporate Security	Provide Security Services for Company Assets	1,445,246	843,846	60,908	2,350,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2008 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)			2,550,598	2,550,598
	Warehouse (Provincial lines)			3,036,141	3,036,141
	Strategic Sourcing Initiative			31,250	31,250
	Supervise Inergi- SMS			125,000	125,000
	Transportation			4,229,497	4,229,497
	Investment Recovery			209,758	209,758
	Inergi Inspection Project			1,269,391	1,269,391
	Other departmental activities			97,364	97,364
	Purchasing			5,014,875	5,014,875
	Transportation			188,058	188,058
	Asset disposal and Investment recovery			376,116	376,116
	Strategic Sourcing Initiative			877,603	877,603
	Support management of warehouse facilities			626,859	626,859
	Other departmental activities			670,489	670,489
Corporate Services SVP	Manage all Corp Services Departments	533,968	555,511	9,522	1,099,000
Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	564,814	592,228	22,232	1,179,274
	Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	261,283	200,945		462,228
	Support Asset Management activities and projects	542,664	257,346		800,010
	Support Finance activities and projects	376,090	365,119	35,097	776,306
	Provide operational support for Transmission and Distribution activities	64,316	30,500		94,816
	Manage IT capital projects and IT strategy	676,859	1,027,817	25,717	1,730,392
	Support Inergi operations	292,069	443,510	11,097	746,676
	Other departmental activities	65,400	68,681	2,216	136,298
	General departmental expenses	160,264	168,305	5,431	334,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2008 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Corporate Controller	Accting policies; External reports; External audit / review	876,525	611,205	57,570	1,545,300
	Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	666,945	465,063	49,692	1,181,700
	Regulatory Finance Activities	357,279	397,191	18,180	772,650
	Manage Inergi- General and Inergi- Finance contract				-
	Revenue analysis and reporting	127,319	299,911	12,120	439,350
	Monitor and support Financial systems and Corporate accounting	453,545	522,115	54,540	1,030,200
	Internal controls	178,883	205,927	24,240	409,050
	Other departmental activities	343,842	323,282	14,626	681,750
	Actuarial consultants	357,186	377,924	14,891	750,000
	Consultants- Bill 198 (Canadian SOX) compliance				-
	General departmental expenses	98,935	93,020	8,045	200,000
Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	130,702	81,386	4,541	216,630
	Insurance- Claims	1,804,591	1,258,349	50,538	3,113,478
	Fiduciary insurance policy	26,237	27,760	1,094	55,091
	IT Costs				-
	General departmental expenses	316,817	200,245	10,740	527,801
Taxation	Compliance activities including tax filings and audits	301,772	240,997	115,644	658,413
	Tax Planning	175,978	140,538	13,437	329,953
	Support Debt issuance	8,127	4,691	620	13,437
	Special Projects	14,111	11,270	1,493	26,874
	Support regulatory filings	7,777	8,646	2,986	19,409
	Support Construction activities	10,452	8,957	1,493	20,902
	Other departmental activities	235,430	188,582		424,012
	Tax Consultants	72,716	58,246	19,037	150,000
	General departmental expenses	33,934	27,182	8,884	70,000
Financial Strategy	Support Regulatory Activities		184,600		184,600
	Support Business Activities		92,300		92,300
	Special Projects		184,600		184,600
	Decision support for lines of business	631,332	420,888	55,380	1,107,600
	DSM		184,600		184,600
	Ontario Hydro Energy			92,300	92,300
	General departmental expenses	17,100	28,900	4,000	50,000

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2008 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
Internal Audit & Risk Mgmt	Audits	1,148,653	670,047	167,880	1,986,580
	Purchasing	93,242	90,801	11,817	195,860
	IMIT	161,109	169,191	5,460	335,760
	Human Resources	13,325	14,099	556	27,980
	Finance	108,442	105,278	10,120	223,840
	Customers	7,604	17,911	2,465	27,980
	General departmental expenses	43,813	30,517	5,670	80,000
Regulatory Affairs	Coordinate HO Filings with OEB (incl. DSM)	1,440,574	808,901	27,584	2,277,059
	Manage HO Relationship with OEB (incl. complaints)	690	51,720		52,410
	Develop and Support Rate Structures and Design for Transmission and Distribution Rates				-
	Support IMO Technical Panel and Make Recommendations for Market Rules for the Ontario Electricity Market	430,310	1,303,344		1,733,654
	Provide Load Forecasts for HO and IMO	373,763	412,381		786,144
	Support Wholesale and Retail Settlement Process	504,787	658,568		1,163,355
	Section 92 Applications	210,328			210,328
	Code Reviews	107,578	175,848		283,426
	Other departmental activities	144,816	244,808		389,624
	All other costs	362,214	737,786		1,100,000
Regul. Affairs- OEB Cost	OEB Billed costs	6,580,081	5,364,919		11,945,000
Law	Overall Assignment of Time	2,856,279	1,991,696	337,025	5,185,000
	Consultants and External Legal Counsel	920,746	642,040	108,643	1,671,429
	General departmental expenses	70,827	49,388	8,357	128,571
Telecom Services	Management of Telecoms Services	1,754,017	1,849,906	71,076	3,675,000
	Data backbone, assets and lines for all users	2,314,303	2,426,632	91,096	4,832,030
	Voice backbone, assets and lines for all users	1,835,984	1,942,463	75,553	3,854,000
	Repairs, adds, changes to telephones	2,242,720	2,372,788	92,291	4,707,800
ETS - Applications Support	Support CSO Applications	91,497	6,645,145	3,656	6,740,299
	Support Finance Applications	2,436,616	1,903,205	153,712	4,493,533
	Support HR Applications	1,712,027	1,811,427	71,372	3,594,826
	Support Passport Applications	1,497,190	1,648,283		3,145,473
	Support Market Ready Applications	1,442,648	5,708,025		7,150,673
	Support Telecommunications Infrastructure	642,194	679,439	26,427	1,348,060

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2008 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	1,768,465	1,618,448	94,430	3,481,342
	Direct Assignments		1,016,154		1,016,154
	General Infrastructure Support	10,783,278	9,907,870	424,494	21,115,641
Customer Support Operations	Inbound calls / correspondence		21,310,020		21,310,020
	Bill Production		9,376,427	18,313	9,394,740
	Data Services- Timesheets for field personnel, Tx operations	458,280	2,596,920		3,055,200
	CSO Support- Management; Training, Communications, Support; Application support Business Analysts		4,415,288	14,752	4,430,040
Settlements	Wholesale and Retail Settlements	450,000	2,550,000		3,000,000
Finance	Accounts Payable processing	783,978	849,872	105,034	1,738,884
	Accounts Receivable processing	625,945	566,765	107,503	1,300,213
	Fixed Assets processing	387,774	229,670	5,569	623,012
	Corporate accounting, Budgeting, Analysis	2,969,972	2,070,974	83,175	5,124,120
	Pension support	24,094	25,493	1,004	50,592
	Inergi Corp. Finance	290,048	685,348	12,783	988,178
HR - Pay Services	Payroll Services and Recordkeepping	1,674,486	1,771,707	69,807	3,516,000
Chair	Overall Assignment of Time	172,423	120,232	20,345	313,000
	General departmental expenses	14,109	9,838	1,053	25,000
Board	Overall Assignment of Time				-
	Audit Fee	324,253	373,276		697,529
	General departmental expenses	325,892	227,246	24,332	577,471

HYDRO ONE COMMON CORPORATE COST MODEL
ACTIVITY COSTS DISTRIBUTED TO BUSINESS UNITS- 2008

		Total Activity Cost to Business Unit			
Function or Service	**Activities Performed**	**Transmission**	**Distribution**	**Other**	**Total 2008 Activity Budget**
(A)	**(B)**	**(D)**	**(C)**	**(E)**	**(F)**
President/CEO Office	Establish performance targets for safety, customer service, reliability	59,778	48,708	2,214	110,700
	Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	239,112	194,832	8,856	442,800
	Develop and maintain relationships with major customers and customer groups	239,112	194,832	8,856	442,800
	Develop and maintain relationships with regulators, shareholder, lenders	239,112	194,832	8,856	442,800
	Monitor, assess and remediate risks to operational and financial performance	119,556	97,416	4,428	221,400
	Influence / Ensure company can adapt to changing regulatory framework and economic conditions	239,112	194,832	8,856	442,800
	Plan for management succession	59,778	48,708	2,214	110,700
	General departmental expenses	227,340	185,240	8,420	421,000
Corporate	Overall Assignment of Time	338,236	235,854	39,910	614,000
	General departmental expenses	41,316	28,809	4,875	75,000
Corp. Secretariat	Overall Assignment of Time	119,540	83,355	14,105	217,000
	General departmental expenses	55,087	38,413	6,500	100,000
CFO Office	Review and approve financial and investment decisions and Provide input to strategy and business plans	98,839	68,921	6,990	174,750
	Provide oversight to Finance functions in timely, reliable reporting information to HO, subs, regulators, investors, shareholder	68,275	66,283	5,243	139,800
	Ensure financial services are provided efficiently and reliably	14,187	13,773	6,990	34,950
	Ensure integrity of, and compliance with, internal controls over regulatory, financial, accounting activities	29,244	33,666	6,990	69,900
	Monitor performance against operational, financial and regulatory targets	41,183	28,717	31,455	101,355
	Ensure sufficient revenue for operating, financial and regulatory needs	37,065	25,845	6,990	69,900
	Support BOD	19,724	13,754	1,473	34,950
	Ensure access to capital on reasonable terms	37,762	21,653	10,485	69,900
	Other departmental activities	1,740	1,370	385	3,495
	General departmental expenses	189,195	148,945	41,860	380,000
Donations	Donations			2,000,000	2,000,000
TOTAL CCFS		73,419,215	120,986,261	24,765,355	219,170,831

HYDRO ONE COMMON CORPORATE COST MODEL
SUMMARY OF CCFS COSTS DISTRIBUTED TO BUSINESS UNITS - 2008

Function or Service	Transmission	Distribution	Other	Total
Human Resources	2,501,252	2,646,474	104,274	5,252,000
Labour Relations	700,560	741,234	29,205	1,471,000
Communications	2,226,590	3,384,148	30,262	5,641,000
External Relations	644,638	795,362		1,440,000
Corporate Security	1,445,246	843,846	60,908	2,350,000
Suppy Management Services			19,303,000	19,303,000
Corporate Services SVP	533,968	555,511	9,522	1,099,000
Info Management & Info Technology	3,003,759	3,154,451	101,790	6,260,000
Corporate Controller	3,460,459	3,295,638	253,904	7,010,000
Treasury	2,278,347	1,567,740	66,913	3,913,000
Taxation	860,298	689,108	163,594	1,713,000
Financial Strategy	648,432	1,095,888	151,680	1,896,000
Internal Audit & Risk Mgmt	1,576,188	1,097,845	203,967	2,878,000
Regulatory Affairs	3,575,061	4,393,355	27,584	7,996,000
Regulatory Affairs- OEB Cost	6,580,081	5,364,919		11,945,000
Law	3,847,852	2,683,123	454,025	6,985,000
Telecom Services	8,147,024	8,591,789	330,016	17,068,830
ETS - Applications Support	7,822,173	18,395,523	255,168	26,472,864
ETS - Infrastructure	12,551,742	12,542,472	518,923	25,613,137
CSO	458,280	37,698,655	33,065	38,190,000
Settlements	450,000	2,550,000		3,000,000
Finance	5,081,810	4,428,122	315,068	9,825,000
HR	1,674,486	1,771,707	69,807	3,516,000
Chair	186,532	130,070	21,398	338,000
Board	650,145	600,522	24,332	1,275,000
President/CEO Office	1,422,900	1,159,400	52,700	2,635,000
Corporate	379,552	264,663	44,785	689,000
Corporate Secretariat	174,627	121,768	20,605	317,000
CFO Office	537,213	422,927	118,860	1,079,000
Donations			2,000,000	2,000,000
Total	73,419,215	120,986,261	24,765,355	219,170,831

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #24 List 1

Interrogatory

Reference: Exhibit C1, Tab 5, Schedule 2, pages 2-3

Preamble: *Beginning in 2007, Hydro One Networks is adjusting the overhead capitalization rate several times within the year as required to reflect actual changes in capital expenditures spending. This will improve the timeliness of the potential E-Factor true-up and result in a better alignment of overhead costs with the capital projects that they support. It is also proposed that the year-end E-Factor true-up, going forward, will be in included in the calculation of the overhead capitalization rate for the subsequent year.*

Questions:

a) Provide a full calculation of 2008 Dx Overhead Capitalization in the same format as the Rudden Report C1 Tab 5 Schedule 2 Attachment A.

b) Provide the E factor for 2007.

c) Provide a revised version of Table 2 including the E-factor for 2007.

d) Provide the $ Impact of the revision on 2008 OM&A and Revenue requirement.

Response

a)

HYDRO ONE DISTRIBUTION CALCULATION OF DISTRIBUTION OVERHEAD CAPITALIZATION RATE		
DISTRIBUTION CAPITAL		
Capital, inc. Cap OH		592.7
Less: Minor Fixed Assets		(39.4)
Less: Capitalized Overhead		(54.5)
Less: Capitalized Interest		(9.9)
Add: Capital contributions		35.6
Add: Removal costs		23.6
DISTRIBUTION CAPITAL		548.0
APPLICABLE Dx CCFS COSTS		
Dx CCFS Costs from Cost Distribution Model		121.0
Dx LBSS Facilities costs		17.7
Operating-Type Dx CCFS costs:		
Inergi-CSO in Dx CCFS		(37.7)
Inergi-ETS CSO Apps in Dx CCFS		(6.6)
Inergi-ETS Market Ready in Dx CCFS		(5.7)
Inergi-Settlements in Dx CCFS		(2.6)
		(52.6)
APPLICABLE Dx CCFS COSTS		86.1
Dx LABOUR CONTENT		
Labour in OM		227.7
Labour in Capital		158.7
		386.4
Dx LABOUR CONTENT		41.1%
Weighted Rate	50.0%	20.5%
Dx TOTAL SPENDING		
OM Spending		380.5
Capital Spending (excluding Overhead Capitalized)		548.0
		928.6
Dx TOTAL SPENDING		59.0%
Weighted Rate	50.0%	29.5%
Dx CCFS Cap=Capitalized Dx CCFS costs		
Weighted Average Rate		**50.0%**
Applicable CCFS Costs		86.1
Dx CCFS Cap=Capitalized Dx CCFS costs		**43.1**
Capitalized Asset Management Costs		
Non-operators		65.5
Non-operator costs to Dx Capital		9.0%
Capitalized Non-operators		5.9

HYDRO ONE DISTRIBUTION
CALCULATION OF DISTRIBUTION OVERHEAD CAPITALIZATION RATE

Operators	40.4	
Operator Costs to Dx Capital		3.0%
Capitalized Operators	1.2	
Customer Care	6.7	
Customer Care to Dx Capital		2.0%
Capitalized Customer Care	0.1	
Dx AM Cap = Capitalized Asset Management Costs	**7.2**	

E-Factor	
Amount capitalized for prior year (2006)	59.8
Amount that would have been capitalized for prior year (2006)	45.4
E-Factor	(14.4)

TOTAL OVERHEAD CAPITALIZATION RATE	**Total Capitalized**	**Capital-ization Rate**
Dx CCFS Cap=Capitalized Dx CCFS costs	43.1	7.9%
Dx AM Cap = Capitalized Asset Management Costs	7.2	1.3%
E-Factor	(14.4)	-2.6%
Total	**35.9**	**6.5%**
Capital	**548.0**	

b) As noted in Exhibit C1, Tab 5, Schedule 2, Hydro One Networks adjusted the overhead capitalization rate during 2007 including a year-end adjustment which trued-up the capitalized overheads to what should have been capitalized. Therefore, there is no E-Factor adjustment required for 2007.

c) See answer b) above. There is no E-Factor required for 2007.

d) See answer b) above. There is no E-Factor required for 2007.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #25 List 1

Interrogatory

References: Exhibit C1, Tab 6, Schedule 1, page 2
Exhibit C2, Tab 5, Schedule 1, pages 1&2

Questions:

a) Provide the following Details of the increase 2006-2008 in Depreciation Expense related to Minor Fixed Assets
   i. What are the main drivers of the increase?
   ii. Details of Capital and OM&A Amounts depreciation rates and expense related to Cornerstone
   iii. The increase in blended asset pool depreciation rate from 2006 8.49 % to 2008 10.81%

b) Did Foster Associates examine Cornerstone? If so what depreciation treatment for O&M and Capital was recommended?

c) Did HO adopt this recommendation and is this reflected in the depreciation expense for minor assets for 2006-2008? Please elaborate.

Response

a.

i. The main driver of the increase in depreciation expense for Minor Fixed Assets is the growth in fixed assets related to Transport & Work equipment.

ii. Fixed assets related to computer software are depreciated using a rate of about 10%. Fixed assets related to computer hardware are depreciated using a rate of 20%.
The bulk of capital spending on Cornerstone will be recorded as computer software assets. Note that computer software is classified as a Major Fixed Asset, not a Minor Fixed Asset.

iii. The increase in the blended Minor Fixed Asset depreciation rate is mainly due to the growth in Transport & Work Equipment assets.

b. Foster Associates analyzed the fixed assets in service at the time of the study. These assets would have included Hydro One's existing computer systems, such as PassPort and PeopleSoft, but not Cornerstone.

c. Hydro One adopted Foster Associates recommendations for depreciating computer software and hardware beginning January 1, 2007.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #26 List 1

Interrogatory

References: Exhibit D1Tab 2 Schedule 1 Page 10 Table 4.2

Question:

a) Provide the 2007 Station Transformer Failure Rate.

Response

a. In 2007 there were 23 Station Transformer Failures.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #27 List 1

Interrogatory

References: Exhibit D1,Tab 2, Schedule 1, Page 15
Exhibit D1, Tab3, Schedule 1, Tables 3 and 4

Preamble: *In the past, the number of poles/year that have entered this Region (3) has been about 30,000 to 35,000, but over the next 10 years the number will increase to as much as 50,000, thereby increasing the number of poles expected to be found at end of life. This information indicates that in the future one can expect an increasing number of pole replacements.*

Questions:

a) Provide the 2006 ACA for poles and compare this to the 2008 ACA.

b) Does HO keep statistics on wood pole failures? If so provide this and discuss what the data show for 2004-2007?

c) Relate the need to accelerate pole replacement to the higher replacements planned for 2008 in terms of planned and actual units in 2006 and 2007.

d) Provide the unit costs for pole replacement 2006-2008.

Response

a. The following table compares ACA pole results from the 2006 Distribution Rate Application (EB-2005-0378) with results from the 2008 Distribution Rate Application (EB-2007-0681).

Asset	Year	ACA Results		
		"Poor" or "Very Poor"	"Fair"	"Good" or "Very Good"
Wood Poles	2006 (EB-2005-0378)	4.1%	0.5%	95.4%
	2008 (EB-2007-0681)	4.2%	0.8%	95%

b. Hydro One does not have consistent statistics on wood pole failures during the 2004 to 2007 period.

c. & d. The following table relates 2008 pole replacement plans to 2006 and 2007 units and identifies unit costs through the 2006 to 2008 period.

Year	2006	2007	2008 Forecast
Planned Volume (units)	6,000	6,700	7,000
Volume Completed (units)	5,193	6,852	-
Funds Spent ($000 000s)	$30.3	$40.1	-
Average Unit Price	$5,841	$5,853	$5,685

Planned replacements are established through pole assessments, and current inspections have identified that 7,000 substandard poles require replacement during 2008. Future requirements will also be based on field assessments and based on the pole demographics presented in Exhibit D, Tab 2, Schedule 1, it is expected that the percentage of substandard poles will increase in time.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #28 List 1

Interrogatory

References: Exhibit D1, Tab 3, Schedule 2, Page 23, Table 6

Preamble: *Activities associated generally with the government's regulations concerning minimum functionality, which account for $64.2 million and $136.5 million in 2007 and 2008 respectively, include the following work:*
o Installing additional smart meters and advanced metering communications devices ("AMCDs");
o Building and expanding the advanced metering regional collector ("AMRC"), and underlying networks to accommodate an increasing number of meters coming on-stream;
and
o Commissioning and placing into service, hardware and software for the advanced metering control computer ("AMCC") to enable it to communicate and transmit quality meter data to and from the meter data management and meter data repository (MDM/R) and the Company's CIS.

Questions:

a) Summarize the 2007 Actual and 2008 forecast accomplishment for meters (units in service and costs).

b) Compare 2007 actuals to forecasts provided to the OEB in the combined hearing.

c) Provide 2007 and forecast 2008 unit costs (capital cost and installation).

d) Provide 2007 actual AMRC and AMCC costs.

e) Compare 2007 actuals to forecasts provided to the OEB in the combined hearing.

f) Provide forecast 2008 AMRC and AMCC costs.

Response

a) In 2007 222,831 smart meters were installed and in 2008 the forecast is to have 370,000 smart meters installed.

b) The combined proceeding only focused on costs up to May 31, 2007 – there were no forecasts for 2007.

c) The 2007 unit cost for AMCD (material and installation cost per meter installed) is $231. The forecast 2008 unit cost is $211 per installed meter.

d) The 2007 actual AMRC and AMCC cost is $8.2M.

e) The combined proceeding only focused on costs up to May 31, 2007 – there were no forecasts for 2007.

f) The 2008 forecast AMRC and AMCC cost is $17.6M.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #29 List 1

Interrogatory

References: Exhibit D1, Tab 3, Schedule 2, pages 27-28

Preamble: *Incremental functionality activities associated with effective use of the smart meters to provide time-differentiated billing to customers and provide Hydro One the ability to leverage its AMI system for other business benefits, which account for $12.5 million and $28.3 million in 2007 and 2008 respectively, include the following work:*
o Upgrades to our CIS system to provide for Time of Use billing and related required settlement changes. This aspect of the Smart Meter program is rooted in the government's desire and directive to create a conservation culture of which time of use rates are an integral part;
o Integration of the end to end systems including business process redesign, This integration ties the AMI systems implemented under minimum functionality with the IESO's MDMR and Hydro One's CIS system to allow the collection of time differentiated consumption data required for TOU billing;

Questions:

a) Provide a breakdown of 2007 and 2008 costs above minimum functionality. (CAMF)

b) Indicate where the 2007 and forecast 2008 CAMF costs are being recorded.

c) If in the SM deferral account is interest being accrued?

d) Is HO is seeking recovery of 2007 and/or 2008 CAMF in this Application per F1 T1 S1 Table 2?

e) Provide any Board or Board staff directions regarding recovery of CAMF.

Response

a) For a detailed cost breakdown of all 2007 and 2008 costs including the costs above minimum functionality please refer to the IR response in Exhibit H, Tab 10, Schedule 28.

b) The Capital costs above minimum functionality are being recorded in USofA account #1555.

c) Interest on all regulatory smart meter asset balances is included in the amounts to be recovered as of April 30, 2008.

d) Yes

e) Hydro One Distribution has followed the general accounting guidelines for smart meters provided in the OEB's letter of June 13, 2006 to all Local Distribution Companies (Board File No. EB-2006-0136), and the "Report of the Board on 2nd Generation Incentive Regulation for Ontario's Electricity Distributors - Addendum for Smart Metering Rates", dated January 29, 2007. The OEB Decision on Smart Meter Costs (EB-2007-0063) dated August 8, 2007 stated that "Costs in addition to minimum functionality can be recovered as part of distribution rates in an individual utility's next rate case".

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #30 List 1

Interrogatory

References: Exhibit D1, Tab 3, Schedule 3, page 2, Table 3

Preamble: *The actual number of (Generation connection) projects that will connect is still quite uncertain. As of June 30, 2007, 34 of the 113 projects that have received a CIA have gone on to request an estimate and 8 projects have actually signed a Connection and Cost Recovery Agreement (CCRA) committing to pay for connection. The forecast number of connections on which the plan is based is shown in Table 3 below.*

Questions:

a) Provide 2006 and 2007 forecast and actual generator connections and total costs.

b) Is the $4.4 million increase in distribution line upgrades (poles etc) reflected in the asset replacement sustaining capital budget or is it considered development capital? i.e. are 100% incremental resources applied for generator connections?

c) How are Under/over forecasts of generator connection activity treated for regulatory purposes.

d) Does the OPA have a forecast of small generators (# and Mw) connected to Dx? If so please provide a copy.

Response

a. The table below shows the forecast and actual generation projects/connections as well as forecast and actual costs for 2006 and 2007. Since the RESOP was launched in the fall of 2006, the forecast for 2006 does not include the expected impact of the RESOP. The table also shows information on Net Metering (NM) projects where the number of connected projects took an upward swing starting 2006 as a direct reflection of the change in NM regulation raising the threshold to 500 kW (from 50 kW). It is worth noting that the number of projects actually connected in a given year is driven by customer timelines and needs, which the LDC has little control over. Forecasts for 2007 take into consideration the RESOP impact.

Forecast vs Actual - Generation Connections

Year	Forecast / Planned (Budget)			Actual		
	Number of Projects		$ M	Number of Projects Connected (Total Capacity)		$ M
	Retail	Net Metering		Retail	Net Metering	
2006	14	12	1.3	0[1]	36 (0.69 MW)	1.5
2007	94	20	6.1	16[2](24.8 MW)	52 (1.05 MW)	1.8

1) In addition, Hydro One did TS mods to enable connection of 1 generator to another LDC system.
2) Nine Micro Generation Projects totaling 0.04 MW are included.

It is Hydro One's understanding that no "retail" generators pursued connection in 2006 as a result of generation proponents waiting for the details of the Standard Offer Program to be finalized before moving ahead with their projects.

b. The basis for the $4.4 million increase in distribution line upgrades is shown as development capital and the determination of that amount is described in the response to interrogatories at Exhibit H, Tab 1, Schedules 23 and 26.

c. As with any other work program, Hydro One expects that in any given year there may be some over or under spending in generator connection activity as compared with forecast amounts. As with other work programs, which are not tracked in variance accounts, there is no specific treatment for regulatory purposes for differences from forecasts.

d. To Hydro One's knowledge, the OPA has no forecast of total small generators (numbers or MWs) connecting to distribution. The Integrated Power System Plan filed with the OEB on August 29, 2007 does provide a forecast number of MW of "customer based" generation which is generation individually less than 500 kW in capacity.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #31 List 1

Interrogatory

Reference: Exhibit D1, Tab 3, Schedule 5, pages 18-23

Preamble: *The Cornerstone Project envisions four staged replacements of core applications which are scheduled to occur between 2008 and 2011. Hydro One intends to retain outside consultants and software application vendors, through a competitive bidding process, to assist it with its replacement program.*

Questions:

a) Please provide the Business Plan and projected Capital and Operating Cost Summary for the Cornerstone Project. (The one page summary filed at D2 T2 S3 IT1 is not adequate for such a major multi-year project).

b) If not included in the response to a), provide the in-service dates for the major components.

c) Provide a copy of the Benefits Realization Plan and analysis for Cornerstone.

d) Relate the benefits listed at D1Tab3 Schedule 5 Page 22 to the BFRP.

e) Provide the projected split in Capital and Operating costs and benefits between Tx, Dx and Other Business units. 2007, 2008 forward.

Response

a) See Attachment A: Hydro One Networks – Business Case Summary Cornerstone Phase One which was approved in February 2007.

b) The planned in-service dates for the four phases are:

Phase 1	Mid 2008
Phase 2	Late 2009
Phase 3	Mid 2011
Phase 4	Late 2011

c) See Attachment B: Value Realization for Cornerstone Phase 1 EAM to this response.

d) The key to relating the benefits listed at Exhibit D1, Tab 3, Schedule 5 page 21 to the Attachment B: Value Realization for Cornerstone Phase 1 EAM is:

Benefits Listed in Exhibit D1, Tab 3, Schedule 5	Attachment B: Value Realization for Cornerstone Phase 1 EAM Section
Enhanced crew productivity due to better materials availability through more efficient forecasting, planning and execution	2.1.9
Optimized O&M and Capital spend through enhanced asset analysis and maintenance.	2.1.1
More accessible information from Electronic Asset Management systems through better leverage of IT.	2.1.3
Improved contract compliance and management through reduction in P-Card and non-PO spend for direct purchase materials and services.	2.1.7
Improved system reliability through higher quality asset data and avoided emergency "trouble" work.	2.1.2
Increased back-office productivity (Designer/Clerical) through reduced costs of tracking work to be scheduled and time prioritizing work.	2.1.6
Work bundling for routine inspections and Preventive Maintenance work.	2.1.5
Improved inventory performance through reduced expediting, material handling, storage costs, returns and excess/obsolete inventory.	2.1.8
Improved warehouse shipping processes and payment reconciliation.	2.1.10
Improved ERS processes through better automation.	2.1.11
Greater control governance around one-time setup vs. regular AP vendor setup.	2.1.12
Improve Transmission customer satisfaction through more detailed reporting and improved connection process.	2.1.4

e) The projected split in Capital and OM&A costs for Cornerstone Phase 1 between Transmission and Distribution are:

	2007	2008
Transmission	$38 M	$39 M
Distribution	$30 M	$31 M

There are no projected Cornerstone costs for "Other Business units".

Benefits have only been identified for cornerstone Phase 1 – EAM to date. The benefits from 2009 to the end of 2015 have been identified as $ 200 million which are split as $ 59 million for Distribution and $141 million for transmission.

Investment Driver
Investment Number:

Date
Title: BCS Template

Hydro One Networks – Business Case Summary
Cornerstone Phase One

Investment Driver:

CC900/CM900 – Business Transformation

This investment driver funds the capital and OM&A component to

- provide more efficient, industry standard business processes
- replace end-of-life Enterprise business systems to meet business needs and achieve 2010 goals
- rationalize shared business data.

Investment Name: Cornerstone Phase One $140M
In Service: June 2, 2008
Previous Release: $6M
Project Total: $146M

Need:

The current installation of Indus PassPort is no longer eligible for vendor support. It has been heavily customized to adapt to current requirements. It does not provide full work management and supply chain functionality, nor does it provide a single asset registry "system of record." Therefore, a significant investment is required or else technology and process solutions will not be available to support the achievement of our business goals and completion of the upcoming capital work program. Moreover, significant internal control and business continuity risks would remain unaddressed.

Investment Summary:

PassPort 6 was installed in Hydro One in 1998 and is currently being utilized for supply chain, work management, asset management, and accounts payable. The 1998 installation was compromised due to two key changes in direction: the decision to include the Distribution side of the business in what had previously been a Transmission-only solution; and the decision to have all Y2K products in place certified and tested a year early, by year-end 1998. In order to make the scope achievable in the available time, much of the functionality that was available within the Passport tool was not "turned on" for the business, and the solution was heavily customized during and after go-live to meet business needs. As a legacy, there now exist numerous bolt-ons and custom solutions that interface with PassPort and attempt to overcome the business limitations of that initial solution. These limitations will hinder the ability of the company to meet its aggressive capital program and continuing to maintain the heavily customized PassPort system is costly and complex.
Phase One proposes to replace the Passport functionality with SAP functionality. The scope consists of and is restricted to doing what is required to "turn on" the SAP product and make it work as designed in the business, with no SAP software customizations. In a business context, "what is required" consists of:

- Changing business processes that currently touch PassPort, to maintain or improve business performance. We will not customize the product to accommodate current business processes; rather, we will replace current business processes with industry standard practices.
- We will reconnect to SAP, replace within SAP, or decommission applications in the interest of three criteria:
  - Mitigate project risk (complexity and cost)
  - Enable future Cornerstone phases
  - Minimize life cycle cost to the business
- Migration or replication of data needed to execute the SAP solution
- Establishment of an effective change management capability within the project to minimize disruption, maximize adoption, and reduce the overall cost and risk of implementation.

Results:

Phase One will bring the following business benefits to Hydro One:

- Improved Asset Lifecycle Decision-Making
- Enhanced Work-Program Planning & Execution
- Set the stage for subsequent phases of the Hydro one System Replacement Strategy.

Costs:

	2006 ($M)	**2007** ($M)	**2008** ($M)	**Total** ($M)	**Net Present Value:**
Capital * and MFA	0	99.9	25.5	125.4	**(60.0M)**
OM&A and Removals	4.2	6.9	7.7	18.8	
Gross Investment Cost	4.2	106.8	33.2	144.2	
Recoverable					
Net Investment Cost	4.2	106.8	33.2	144.2	

*Includes overhead and AFUDC at current rates

** Funds shown above are for the Total Project including prior and current releases

Alternatives

ALTERNATIVES CONSIDERED

Alternative 1: "Lockdown" of Current Passport 6 Solution

This alternative would be to maintain the current solution for as long as possible, notionally on the order of 5 years. This would represent the lowest cost alternative in terms of current investment.

However, this alternative is not recommended for the following reasons:

- The current installation is inflexible, unsupported, and costly to maintain, especially given the large number of bolt-on and custom applications that currently connect with PassPort. Staff with the technical expertise to support and maintain this installation are scarce.
- The current version carries a significant business continuity risk. It is out of vendor support, so patches and other security updates are not available from the vendor.
- The current installation perpetuates manual internal control processes to support Bill 198 compliance costly and complex; moreover, additional manual internal control processes would be required to address outstanding internal audit and Auditor General issues.
- The current installation is inadequate to support the needed business improvements to achieve our business goals and complete the upcoming capital work program.
- Maintaining the current system would leave internal audit and Auditor General issues unaddressed
- **The current installation would not support the achievement of Hydro One's 2010 goals**

Therefore, despite being the lowest cost, this alternative is not recommended due to its poor suitability to Hydro One's business needs and overall IT strategy.

Alternative 2: Like-for-like Software Replacement – Minimal Increase in Functionality

This alternative merely stabilizes the infrastructure.

This alternative would ensure the fundamental integrity of the system on a go-forward basis. Given the extent of customization of our current system, an "upgrade" of Passport is not truly a simple "upgrade". Upgrading the current EAM to a more current version on any software platform would more correctly constitute a full replacement and change management effort would still be significant. Nonetheless, a feasible course would be to replace the currently installed Indus Passport version (6) with the up-to-date version (10). In the RFP stage of this project; two vendors responded with proposals that addressed this "like-for-like" Indus Passport replacement option. One of these was short listed to the presentation round.

The short-listed "like-for-like" respondent's pricing was approximately 20% lower than the Accenture bid. Implementation of this solution would enhance controls and operations to a satisfactory level. Moreover, this would provide Hydro One with a vendor-supported platform ensuring on-going maintenance and updates which are currently not available for the existing version at Hydro One.

However, the "like for like" proposal provided much less functionality than specified in the RFP. The short-listed proposal was unanimously assessed by the Hydro One selection team to have an overall "poor" final rating primarily related to:

- Poor overall suitability to Hydro One's needs:
  - poor suitability for the Hydro One System replacement Strategy
  - **would not provide the functionality to support achievement of Hydro One's 2010 goals**
- Weak product offering:
  - poor user interface; very limited future improved functionality potential
  - the proposal required customization of the software – not "out-of-the-box"
  - limited work management reporting functionality
  - no estimating or "what-if" forecasting functionality of the type specified in the RFP
  - no Asset Management analytics
  - Finance needs were not fully addressed by this solution
- Weak integration partners:
  - no experience of this vendor and integrator working together on past Passport installs or upgrades
  - limited change management expertise
  - limited grasp of Electricity T&D Industry standard practices

Given the fact that the resulting functionality did not address the needs in the RFP and given the concerns with the proposal listed above, this offering was rejected by the RFP evaluation team. Therefore the "Replacement" alternative is not recommended.

Investment Driver Date

Investment Number: Title: BCS Template

RECOMMENDED ALTERNATIVE AND RATIONALE:

Alternative 3: Implement Full EAM Solution Including Industry Standard Processes

This alternative is recommended due to:

- Good overall "fit" with Hydro One's business needs:
  - Supports achievement of 2010 targets and beyond, and sets stage for future phases
  - Provides system functionality and business processes to break through productivity limits of current state
  - Enables knowledge retention – 1,500 employees retire over next 5 years
  - Provides stable IT environment going forward
  - Standard functionality and processes enables more competitive tendering of IT work and outsourcing contracts
  - Improves internal controls and increases the quality of business processes
  - Significant benefits from integration of 4 phases of Cornerstone Program.
- A strong product:
  - Meets all functionality requirements specified in the RFP out-of-the-box for supply chain, asset registry, A/P, and work management
  - Full support for Bill 198 compliance
  - Would help us address internal controls issues raised by Internal Audit and the Provincial Auditor General.
  - Strong user interface
  - Solution has drill up/drill down capability; can eliminate COGNOS.
  - Broad availability of staff with the technical skills to maintain and support
- A strong integrator:
  - Demonstrated clear understanding of Hydro One objectives/vision/end to end solution needs.
  - Experienced project team
  - Robust change management methodology.
  - Strong offering of Electricity T&D Industry standard business processes and implementation practices.
  - Broad history of implementation in the Electricity T&D sector; over 200 utility SAP installations
  - The above strengths have been validated through their work in the now-complete Discovery phase.

Recommendation of Alternative 3 based on currently committed Phase 1 benefits included in NPV, and external benchmarks for remaining 3 phases of Cornerstone which demonstrate value of integrated solution this alternative sets up

ALTERNATIVES COMPARED

Business Value	**Business Risk**			**Comparison**
	Alt 1	Alt 2	**Alt 3**	
Reliability	M	M	L	Alt 3 provides the basis for better decision-making on asset development and maintenance
Customer	L	L	L	
Competitiveness	H	M	L	Alt 1 (status quo) and Alt 2 (like-for-like) do not support Hydro One's competitiveness objectives. Alt 3 provides the most anticipated business benefit.
Regulatory/Legal	H	M	M	Alt 1 does not enhance regulatory readiness and could compromise future filings
Safety and Environment	L	L	L	
Reputation	L	L	L	
Financial: Initial Cost ($M)		60.0	144.2	*Costs in $M*
PV Cost/NPV ($M)		(23.8)	(60.0)	*NPV figures shown represent comparison against Status Quo.*

Notes:

- *The Alternative 2 costs have not been put through the same level of due diligence (Discovery stage) as have the Alternative 3 costs.*
- *The benefits calculations for the recommended alternative are based on high level design only. These benefits will be further refined as detailed design proceeds.*

Project Risks and Mitigation:

Data Needs; Data migration: Today, asset and business data resides on dozens of systems and hundreds of distinct databases. The data is of varying currency and quality. The problem of identifying needed data is a complex problem for the project to solve. Dimensions of this risk include: making correct choices of what data is needed by Asset Management and the service-delivery LOBs finding reliable sources of existing data, and migrating it to the new system.
***Mitigation*: The project plan includes a substantial data needs identification and migration effort.**

Implications for Inergi Deal/relationship: Dimensions of this risk include:

- The magnitude of process change for Inergi, especially in the Supply Chain business.
- A lack of clarity on whether the project would yield benefits in terms of reductions in costs or improvements in service related to Inergi-performed work. There is the risk that we will have difficulty arriving at a revised commercial contract that will serve us well in light of the changes being made by Cornerstone Phase 1
- Sensitivity for the relationship, given that Accenture is a competitor of Inergi/Cap Gemini, and that we will be more than halfway to contract expiry by the time the SAP product goes live.

***Mitigation*: To mitigate this risk, Inergi staff are key members of the Project Steering Committee and the Project Team, including the Change Management team.**

Ongoing LOB Staff Participation: Cornerstone Phase One is beginning at a time when Hydro One is experiencing a dramatic growth in its capital work program. The very same staff, that are critical to success of Cornerstone, are needed to support the work program. Ensuring ongoing availability of staff to support project efforts will be a challenge.
***Mitigation*: Each LOB Vice President has signed off on the project scope and resource requirements. The project Steering Committee includes the Vice Presidents of all affected Lines of Business. This will provide a forum for rapid escalation of any resourcing threats to project success.**

Scope Management: There is a risk that the scope will broaden (heightening the risk of project failure due to complexity and cost) or narrow (heightening the risk of failure due to limited value release relative to expectations.)

***Mitigation*: The contract with the Integrator is a fixed price contract for defined scope. In addition, leading project management processes and project governance will be used to manage scope and costs.**

Change Management: Staff resistance to the change, and especially any changes in processes or roles, is a key risk to the success of Cornerstone Phase One. Contributors to this risk include fear of job loss, skepticism given past IT projects that are seen as unsuccessful, the current labour relations climate, and the big (and growing) capital work program. Applications that currently connect to PassPort may cease to function, and this and other "bumps in the road" during implementation can contribute to disruption and resistance.
***Mitigation*: In recognition of this risk, Change Management is a key component of the project design and a major reason for the selection of Accenture as integrator.**

Benefit Realization: Large system replacement and process improvement projects have a history of yielding disappointing benefits to the business. There is a risk that Cornerstone Phase 1 will fail to deliver cost avoidance or efficiency improvement benefits, or some of the other non-monetized benefits that are the basis of the decision to proceed with this investment.
***Mitigation*: The project plan incorporates a Benefits Realization Plan that will:**

- **develop and track changes to the business that are necessary for benefits realization, and**
- **develop metrics to allow monitoring and reporting on the realization of each key benefit after cutover to the new solution.**

Investment Driver Date

Investment Number: Title: BCS Template

Regulatory Considerations:

No significant regulatory issues anticipated other than standard need and prudence justification.

Release Number:	**Included in Business Plan: Yes** (Yes / No) – If No, say No and discuss implications in Project Risks	**Planner:**	
This Release ($M):	**Previous Release ($M):**	**Future Release ($M):**	**Current est. of Total Cost ($M):**

Signature Block:

Submitted by:	**Title: Chair Cornerstone Steering Committee**	**Date:**
Reviewed by:	**Title: Chief Financial Officer**	**Date:**
Recommended by:	**Title: Acting President and CEO Chair Executive Committee**	**Date:**
Approved by:	**Title: Hydro One Board of Directors**	**Date:**

Scientific Research & Experimental Development Tax Credits (SR&ED):

- Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? NO

  (A technological advancement is new technical knowledge that is not publicly available, goes beyond routine practice, solves a scientific or technological barrier, and is acquired through experimentation. Extending existing programming environments, or overcoming their limitations, may give rise to a technological advancement).

- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? NO

  (A Technological Uncertainty arises when the solution, or the method of achieving it, is not readily apparent to appropriately skilled and experienced persons, i.e., all known approaches are inadequate, resolution increases company knowledge, it can arise from functional, cost or time targets, methodologies and system integration. This could also arise if the proposed solution has not been implemented in an environment or scale similar to Hydro One and there is technical uncertainty as to whether it can be modified to work in our environment. Technological uncertainty could also exist due to the unavailability of third-party proprietary information.)

Attachment B

Value Realization for Cornerstone Phase 1 EAM

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Value Realization for Cornerstone Phase 1 EAM

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Executive Summary

The Cornerstone Value Realization (VR) effort has yielded a commitment from Hydro One senior leadership to a $200M challenge target for the Phase 1 benefits case. The benefits case stands at 12 agreed benefits, totaling $86M to $202M (gross of incremental staff changes). The benefits are derived largely from three key value levers underpinned by Cornerstone Phase 1 application, process and organizational changes. These value levers are:

1) A single asset registry with a uniform hierarchy and selective integration to legacy databases;
2) Greater process transparency, integration and collaboration (enabled through the application and process changes) across Hydro One's lines of business (LOB); and,
3) Enhanced compliance to the underlying processes and data requirements.

The VR program was formalized to conduct a high-level quantification of eight of the most likely and material benefits (the "super-8"). The outputs of the high-level Discovery stage estimation were agreed and approved in February 2007 at $77M of a $77M to $222M range, cumulative over 7 years. These were based on inputs from Hydro One, Inergi, SAP and Accenture. During Design, the LOB and VR teams refined the "super-8" benefits, developed and screened an additional 20+ benefits (resulting in a net addition of four benefits), identified associated enabling actions, and took them through the Business Process Design (BPD) workshops to assess their validity in the as-designed Cornerstone solution. Benefits not considered at the end of Design were ruled-out or rolled into existing benefits based on scope, phasing, or double-counting with other projects / initiatives. The value of Cornerstone Phase 1 benefits from this analysis is $86M to $202M, cumulative over 7 years.

The bottom-up analysis by the teams also identified a number of qualitative and intangible benefits that significantly add to the comprehensive benefits case for Phase 1 as well as future Cornerstone phases. Foremost amongst these are:

1. ***Laying the foundation for future benefits:*** There is a consensus view across the Cornerstone teams and LOB leadership that Phase 1 lays the foundation for significant future benefit streams across the corporation as future phases of Cornerstone are rolled out;
2. ***Enhanced customer satisfaction:*** nearly all the benefits will enhance Hydro One's ability to better meet its customers demands for reliable and timely service; and,
3. ***Enhanced compliance and responsiveness to Regulators:*** With more accurate, complete, and accessible data – Hydro One will be able to further increase its compliance and responsiveness to Regulatory requests and demands with more timely responses and proactive contributions.

In Accenture's experience, the Cornerstone Phase 1 benefits developed by the team are typical and reasonable benefits for this type of implementation and program. Accenture is confident the bottom-up analysis conducted by the Cornerstone LOB and VR teams in Phase 1 followed the VR methodology. Most critically, the teams met the requirement to engage the business in the development and support for the benefits. Accenture's only two material caveats for continued success, is that to achieve the benefits: 1) All parties must meet their VR responsibilities and obligations regardless of whether or not their respective portion of the business is a net beneficiary or contributor to the overall corporate benefit; and, 2) Sustained leadership commitment to realizing the full value of the program, and continued support for VR methodology through the life of the project is essential to ensuring the realization of the benefits across the dimensions identified by the teams.

To ensure a continued focus on value, the opportunities for continuous improvement, and ultimately, value realization through Cornerstone it is recommended that:

1. The Hydro One Executive accept the Phase 1 challenge benefits target of $200M; and
2. Hydro One and Cornerstone leadership commit to providing the sustained leadership necessary to drive value and continuous improvement throughout the lifecycle of the implementation and throughout Hydro One going forward.

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Overview

This document has three objectives:

- First, it provides:
  - The context of the Cornerstone VR program;
  - The purpose and role of VR;
  - A summary of the work to date.

- Second, it provides:
  - A summary view of the benefits;
  - Updates to the "original-8" benefits agreed to in February 2007 prior to board approval;
  - Estimates of the additional benefits expected in Phase 1 Cornerstone;
  - Recommended Key Performance Indicators (KPI's) for tracking the continuous improvement of the associated Cornerstone impacted business processes;

- Third, it outlines the process for enabling Value Realization After Go-live

1.1 The context of Value Realization on the Cornerstone project

In the beginning, Cornerstone was deemed to be a *"like-for-like"* systems replacement program. In that context, the potential business value derived from the Cornerstone investment was deemed to be immaterial to the decision to proceed – a critical business system was at risk, and its replacement was justification enough. However, the Cornerstone team invested several weeks of effort during the Discovery stage in the autumn of 2006 to identify and categorize Cornerstone's benefit opportunity areas by approximating potential benefit against likelihood/complexity to achieve the benefit.

From this point forward, Cornerstone and Hydro One leadership created and tasked the VR team to support the LOB leads and their teams to identify, quantify and establish business support for the detailed benefits arising from Cornerstone Phase 1, and to develop a program to ensure their realization. Through the Design stage, the LOB and VR teams have refined the "super-8" benefits, screened out approximately 11 of the 20-odd additional benefits based on issues of scope, phasing, materiality, and the potential for double-counting with existing benefits, and rolled five into other benefits that covered similar functionality or achieved closely related benefit. The LOB and VR teams have developed and screened an additional 20-odd benefits (resulting in a net addition of four benefits to the "super-8"), identified associated enabling actions, and taken all of them through the BPD workshop process to assess their validity/relevance in the as-designed Cornerstone solution. The VR team has also had a member from the Hydro One Corporate Performance Analysis department seconded to it in order to help the VR and Cornerstone functional teams develop the metrics and framework for measuring the performance improvements driven by Cornerstone. And finally, the VR team has worked with the LOB leads to socialize the benefits with the LOB VP's and key reports through the course of the summer months.

Driving these efforts is a growing consensus within the Cornerstone team, and Hydro One leadership that Cornerstone represents an opportunity to renew Hydro One's commitment and drive to developing a culture of excellence and continuous improvement.

1.2 The purpose of a focused Value Realization program?

Value Realization serves two key purposes. First and foremost it provides Hydro One an opportunity to develop a focused program of performance management and continuous improvement tied to the business capabilities, processes, and systems being examined and impacted by Cornerstone. If all four phases of Cornerstone are realized as currently planned – this will effectively provide Hydro One the opportunity to re-energize its commitment to developing a culture and methodology for driving continuous improvement into all corners of the organization.

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Secondly, a focused VR program is best practice component for large system implementations and their ongoing support; especially those impacting as many core business processes Cornerstone does. It is a best practice of implementation and of Enterprise Resource Planning (ERP) solutions. There is a higher probability of acceptance and of realizing the anticipated benefits of implementing an integrated solution if a VR capability is put in place that provides the following elements:

- An understanding of the nature and size of the solution's benefits;
- An understanding of and commitment to a set of enabling actions for the business, the program and the sustainment / enablement organization that will better ensure the realization of the solution's value at go-live; and,
- Metrics and a framework, developed in concert with the business, for tracking the realization of solution's impact and value.

1.3 The Guiding Principles of Value Realization

The following guiding principles lie at the heart of the VR effort and are necessary pre-conditions to its ongoing success in driving a culture of excellence and continuous improvement around the Cornerstone program and its areas of impact.

- *The greater good of the corporation and its stakeholders is our singular focus.* Much of Cornerstone's potential value and specific Phase 1 benefits lies in its ability to allow greater transparency and integration across a complex and large organization. There will be gives and takes within and across LOB's and parts of the corporation. However, all parties will need to be focused on ultimately driving out the greatest benefit for Hydro One and its stakeholders.
- *Line Management continues to own and drive the value opportunities provided by Cornerstone.* For the program to realize its full potential, the business will continue to shape, champion, drive the VR program and most importantly, own its outputs.
- *Tight collaboration between the business and Cornerstone is critical to the ongoing success of the VR program.*
- *Focused VR team driving the methodology and process to support the LOB's and business.* To be successful in identifying and realizing the benefits from Cornerstone Phase 1 and future phases, a dedicated team provides the focus to continuously identify, drive and support the Cornerstone and business leadership in all aspects the VR program.

Ultimately, VR provides Cornerstone and Hydro One leadership a management tool to continuously improve the efficiency and effectiveness of the areas impacted by the Phase 1 Cornerstone program.

2 Cornerstone Phase 1 benefits

The Cornerstone VR effort has yielded a commitment from Hydro One senior leadership to a $200M challenge target for the Phase 1 benefits case. The value of the final twelve Cornerstone Phase 1 benefits is between $86M - $202M (cumulative over seven years), or $14M - $34M per annum at steady state. The benefits were calculated based on 2005, 2006 and 2007 YTD numbers with modest ramp ups in volumes, program $ between 3-5% per annum. If the work program increases significantly, these benefits may also increase.

The total is broken down into twelve individual benefits, and the commitment by line of business is displayed, as follows:

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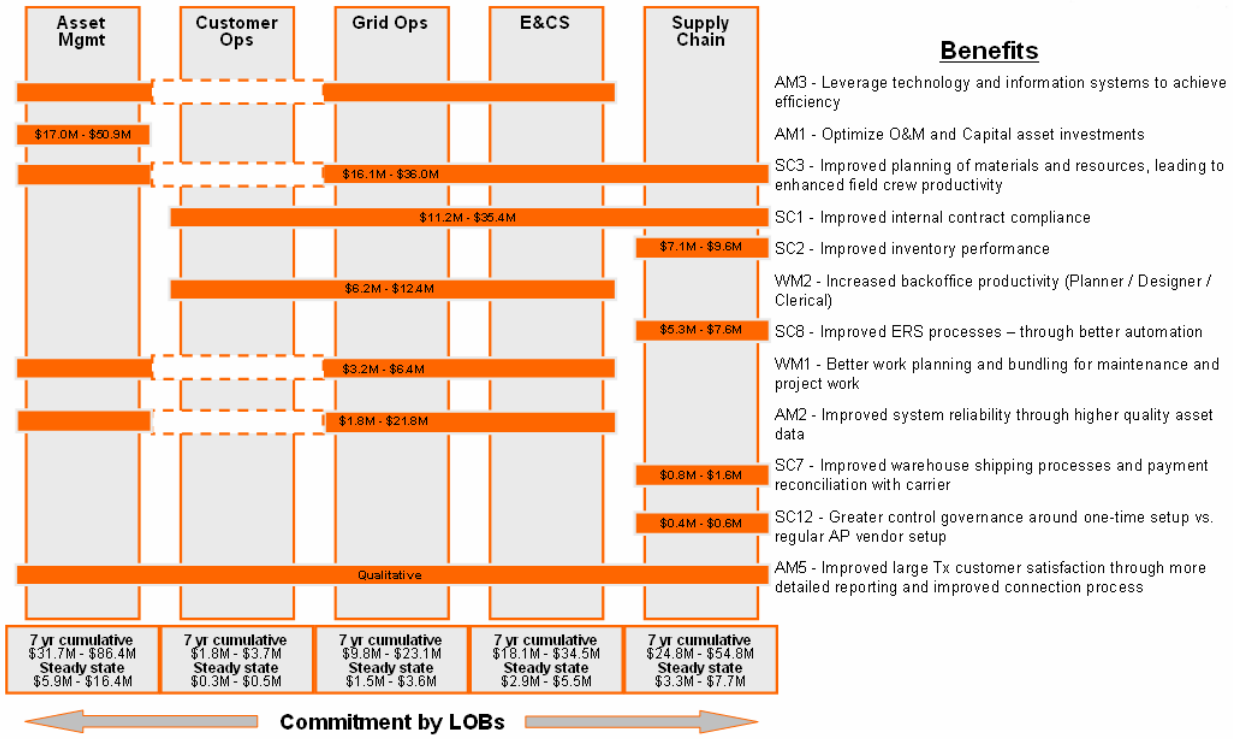

The estimates at the conclusion of Design provide updates to the "top eight" benefits initially approved in February (which were selected from a longer list of about 40 benefits), and an additional four benefits which were developed during the course of the Design stage. The approved Discovery stage benefits in February totaled a range of $77M-$222M (cumulative) over seven years. During the course of the Design stage, approximately twenty additional benefits were reviewed - of which sixteen were either screened out of further consideration (through the litmus tests of likelihood of achieving, scale or importance[1], scope, phasing, and the potential for double-counting; either with existing business cases for programs recently completed, underway or planned to complete during the 2008-2015 benefits horizon for Cornerstone Phase 1) or rolled into the existing benefits as supporting line items. The remaining four have been added to the Cornerstone Phase 1 benefits case.

The twelve Cornerstone benefits have been quantified and refined through the course of the design workshops and further testing and review with key stakeholders. This process has resulted in a better reflection of what the Cornerstone Phase 1 solution will be delivering in terms of scope, functionality, and timing. For all but one of the benefits (SC1 – Contract Compliance) – the benefit values are gross and have not netted out the potential incremental staffing costs to achieve.

Hydro One faces significant growth in its work program, and as such intends to reinvest any savings realized by Cornerstone Phase 1 to complete additional work and improve the condition of its asset base.

- [1] A number of the benefits are not immediately material in simple $$ terms. The inclusion of these benefits was heavily debated but in the end the team has agreed to keep them in the recommended benefits case because of their impact in terms of being a bellwether for compliance or as a foundation for future phase benefit.

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2.1 Description of individual benefits

The following sections detail the individual benefits, and their metrics, assumptions, dependencies, key drivers and enabling actions.

2.1.1 (AM1) Optimize O&M and Capital Asset Investments

Description: Optimize O&M / Capital asset investments to manage operational risks over the asset life cycle. SAP core functionality will provide for the first time, a real-time defect management system, financial and technical reporting capabilities at the asset level to facilitate O&M / Capital tradeoffs for optimizing asset life cycle and improving decision making for all assets. This will allow planners to optimize asset useful service life by (1) readily identifying/eliminating the "lemons" of the fleet & those assets that are at the edge of the "bath-tub" curve; and (2) supporting maintain/refurbish/replace life cycle decisions on the "entire" fleet of assets.

Planners are presently making the "right" asset decisions, but they are not necessarily making the "optimal" asset decisions because information on all our assets is not presently available. For example, we will be able to easily compare breaker reliability and ongoing preventative/corrective maintenance costs to support short term maintenance/refurbish/replace decisions and long term breaker asset management strategies.

It is assumed that, initially, only a small 1-3% benefit will be achieved in Phase 1 with core SAP functionality and that significant additional value release will occur later in Phase 2 with implementation of Meridium APM to optimize preventive maintenance work programs e.g. based on Meridium implementation at BCTC, a reduction of 25% in O&M & $18M in capital was realized in their initial 3-year implementation.

Also, the new SAP tool will facilitate/support Regulatory Compliance and the preparation of Regulatory Rate filings by providing comprehensive asset history, performance & condition information to support work programs and spend levels; justify reduced OEB mandated facility inspections (e.g. reduce wood pole inspection frequency); and reconciling work accomplishment and financial reports at the asset level. This will mitigate the risks of potential Regulatory Penalties associated with having the necessary asset management processes and asset condition information systems. A good example of these potential risks is highlighted by the $9.3M regulatory penalties levied against Con Edison for the 2006 NYC Blackout citing that the primary cause of the blackout was the company's failure to address a multitude of pre-existing problems and issues associated with the operations, maintenance and oversight of their network.

Expected Benefit (no change from Post-Discovery Stage, Feb'07 Approved values):
Cumulative Benefit range (2008-2015): $**17.0M to $50.9M**

Intangible Benefits: Reliability Improvement, Safety, Customer Satisfaction, Regulatory Relationship, Reputation, Employee satisfaction

Cornerstone key drivers of the benefit:

1. Single, comprehensive asset registry
2. Track life cycle costs/work tied to Specific Asset
3. Provide visibility and integrated view of all Planned/Corrective Work
4. Analyze anomalies/patterns to address problem areas

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Assumptions and Dependencies:

- Two years of data will be required as a minimum to stabilize SAP financial and technical reporting & to enable asset specific spend levels to be compared to baselines. Benefit ramp up to be 0%, 10%, 30%, 50%, 100% from 08-12
- Meridium "Quick-win" to enable enhanced condition based maintenance capability for Transformers & Circuit Breakers

2.1.2 (AM2) Improved System Reliability through higher quality Asset Data

Description: Creation of a single high quality asset registry with correct hierarchies will improve reliability by proactively identifying and managing the correction of defects before they become emergency trouble work. This should also reduce safety incidents and increase customer satisfaction via fewer unplanned outages.

Expected Benefit: The value of this benefit has gone down from *Post-Discovery Stage, Feb'07 Approved values* because it was decided during Detailed Design that the LFACA db will not be converted or integrated in Phase 1. This effectively takes the Dx Lines portion of the future benefit stemming from SAP out of the benefit calculation.

Post-Discovery Stage, Feb'07 Approved values:
Cumulative Benefit range (2008-2015):
- $4.8M to $57.1M

Post-Design Stage, Aug'07 Refined values:
Cumulative Benefit range (2008-2015):
- $1.8M to $21.8M

Intangible Benefits:
- Employee pride increased by proactively getting ahead of unplanned failures through better defect management.
- Increased customer satisfaction through fewer equipment-failure related impacts to reliability.
- Increased regulatory compliance especially with respect to NPCC system error and defects management.

Cornerstone key drivers of the benefit:
1. Single repository for defect management and more robust process surrounding defect management.
2. Develop Integrated end-to-end PMO process
   a. Set-up Preventive Mtce Strategies, Plans & Items Set-up
   b. Develop asset failure codes for each asset
   c. Report Inspection, condition & defects at each asset
3. Implement maintenance strategies/plans (and FEGs) that make efficient use of Planned outages to bundle work & maintenance activities
4. Leverage improved capabilities for joint planning & scheduling of work to increase ratio of planned / corrective work

Assumptions and Dependencies:
1. Asset condition and failure codes will be tracked against the established asset hierarchy in SAP

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2. Condition and failure codes will be readily accessible to planners, supervisors, and managers in all LOBs
3. Historical data will not be migrated and therefore not readily available to aid decisions
4. Level of effort to report and collect condition and failure data will be comparable to what it is today
5. New process directs resources at priority defects in a timely manner to avert most failures
6. Requires creation of a single high quality asset registry with correct hierarchies, and the establishment of the correct level of reporting / tracking in SAP to allow visibility of corrective work to be done.

2.1.3 (AM3) Leverage Technology and Information Systems to Achieve Efficiency Improvement in Search and Reconciliation Work Activities

Description: Many staff in Hydro One spend a considerable amount of time searching out and reconciling information in order to execute their day to day work accountabilities. The implementation of integrated tools and processes that span business processes and provide transparency and access to consistent data that can be viewed by appropriate staff in functional groups is expected to reduce the amount of time staff spend searching and reconciling data.

Post-Discovery Stage, Feb'07 Approved values:
Cumulative Benefit range (2008-2015):
- $16.0M to $18.9M

Post-Design Stage, Aug'07 Refined values:
Cumulative Benefit range (2008-2015):
- $17.2M to $20.2M

Intangible Benefits: Labour productivity; Staff retention; Regulatory relationship

Cornerstone key drivers of the benefit:
1. Single, comprehensive asset registry
2. Synchronization & data audits to external systems
3. Capture knowledge and link it to a specific asset or functional location for easy access
4. Establish Source of Record for all Asset Characteristics

Assumptions and Dependencies:
- Benefit calculation is based on a conservative number of staff most impacted by asset data related search and reconciliation issues across the LOB's.
- Assumes no benefit in 2008 and then a gradual benefit ramp-up from 2009 to 2011.
- Requires that staff adhere and buy into the SAP philosophy of a central asset registry for all T&D assets enabling easy access and readily available, transparent, and consistent information

2.1.4 (AM5) Improve large Tx customer satisfaction through more detailed reporting and improved connection process

Description: Improve large Tx customer satisfaction by providing project management transparency, workflow capability & work management status reporting associated with new customer

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projects/connections. The basis for this improvement is twofold: 1) improving performance of meeting customer commitments, and 2) providing better, more effective response to Customer Project inquiries.

Expected Benefit:

Cumulative Benefit range (2008-2015): N/A (intangible)

Intangible Benefits: All considered intangible

Cornerstone key drivers of the benefit:

1. Single, comprehensive asset registry
2. Provide project management transparency, workflow capability & work management status reporting associated with new customer projects/connections.

Assumptions and Dependencies:

- Cornerstone solution will contribute 0.25% / year improvement in overall customer satisfaction & customer commitments met
- Improve customer satisfaction by:
  - Reducing customer connection times, streamline connection process and handoffs (reduce cost of service)
  - Improving appointment scheduling for Customer work
  - Reducing cost of multiple site visits for Customer work
  - Reducing costs of tracking Customer information (Load, specific requirements) and tracking of project initiation data (Transmission)
  - Providing self service capabilities to review project status

2.1.5 (WM1) Better work planning and bundling for maintenance and Project work

Description: Further improvements in having the right work identified at the right time for the right people. Results in reduced windshield time, better flexibility to address contingencies, and reducing wait time. Other work tasks made available to fill in some down time or delay time. Also reduced computer time for field staff in some LOBs. This includes not only maintenance but also project work for all staff for whom work will be planned, scheduled, and visible in the system.

Expected Benefit:

This benefit was slightly reduced from the *Post-Discovery Stage, Feb'07 Approved values* because E&CS reduced their impacted population slightly from 600 to 300 to better address those ECS fieldworkers actually impacted by outage cancellations or delays and the benefit attributed to Customer Ops has been removed.

Post-Discovery Stage, Feb'07 Approved values:

Cumulative Benefit range (2008-2015):

- $5.42M to $11.8M

Post-Design Stage, Aug'07 Refined values:

Cumulative Benefit range (2008-2015):

- $3.2M to $6.4M

Intangible Benefits: 90% customer satisfaction; Top quartile reliability (T&D)

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Additional non-quantified benefits:

1. Other benefits (ie. Rationalize CAPEX & OPEX) may reduce overall volume of PM
2. Better ability to bundle time based PM.

Cornerstone key drivers of the benefit:

1. All work in one system – PM, PS.
2. Early visibility of work using AM notifications to populate SAP.
3. All dependencies known to allow either bundling of like work or advancement of work where all dependencies are met.
4. Marginally improved integration with Outage Management System (OMS) – from both a systems and process perspective.

Assumptions and Dependencies:

1. Work reporting will be such that we can track / separate some "non productive" work
2. Work efficiencies from reporting & planning improvements are captured under "Crew Productivity" Benefit

2.1.6 (WM2) Increased back-office productivity Planner / Designer / Clerical

Description: This benefit is realized in the people & processes involved with planning, scheduling, tracking, & reporting work that has been awarded - typically in the 0-12 month range. New processes & tools will facilitate the tracking, management, planning and visibility of all work. Many current manual processes and rework will be eliminated.

Expected Benefit:
This benefit was slightly increased in CO due to a rise in the number of impacted staff from 60 to 300.

Post-Discovery Stage, Feb'07 Approved values:
Cumulative Benefit range (2008-2015):
- $4.83M to $9.66M

Post-Design Stage, Aug'07 Refined values:
Cumulative Benefit range (2008-2015):
- $6.2M to $12.4M

Intangible Benefits: 90% customer satisfaction

Cornerstone key drivers of the benefit:

1. Reduced number of systems used for work management (eg. Elimination of Work Request System, AUPR, and reduced use of P3E) – therefore fewer systems to manage, enter data etc.
2. Improved timeliness and quality of reporting and work status.
3. Much easier analysis of work management metrics.
4. Incremental improvements in time reporting (eg. Better front-end validation leading to less errors and rework).

Assumptions and Dependencies:

1. We use common tools & processes across the LOBs to plan & manage work
2. Many CO benefits are realized from WEP
3. Every database used to manage work 0-12 months eliminated will produce reduce effort
4. Use of clerical staff to input will remain same in Phase 1. Reduced in Phase 2

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2.1.7 (SC1) Improved Internal & Supplier Contract Compliance

Description: This benefit is derived from all users purchasing standardized materials and services off negotiated contracts at agreed prices, terms, etc. (i.e. no maverick spend). Today, users unfamiliar with policies often bypass the process if supplier discounts are not available or time consuming to find. The ability to more effectively monitor supplier contract compliance will improve as more spend is against contracts for future analysis.

Expected Benefit :
This benefit changed as a result of further analysis conducted by the SC team through the course of Design.

Post-Discovery Stage, Feb'07 Approved values:
Cumulative Benefit range (2008-2015):
- $17.36M to $31.68M

Post-Design Stage, Aug'07 Refined values:
Cumulative Benefit range (2008-2015):
- $11.1M to 35.4M

Intangible Benefits: Safety, Customer Satisfaction, Regulatory Compliance (Bill 198 etc), Employee satisfaction, Increased Skill and Expertise

Cornerstone key drivers of the benefit:
1. Cleaner and more readily available data to encourage increased use of existing catalogues and contracts
2. Focus on compliance, including complimentary reporting, to move individuals off P-Card and non-PO spend toward approved contracts

Assumptions and Dependencies:
1. Greater use of contracts/contract functionality in SAP
2. Reduction in use of Pcard for most items (Pcard is typically used for small purchases)
3. Greater supplier performance visibility (ex. quantity bought vs quantity received)
4. Reduction pricing errors/missed discounts
5. Reduction payment errors
6. Visibility to approved supplier contract items
7. Greater spend analysis with consolidation of items
8. Increased transaction accuracy
9. Increase in supplier performance management
10. Better document consistency
11. Costs associated with Compliance enforcement are off-set by increased wrench time.

2.1.8 (SC2) Improve Inventory Performance

Description: The benefit measures the reduction in material inventory, due to a decrease in material returns and excess/obsolete inventory. It also captures the reduced expediting, material handling & storage costs, due to this decrease. This benefit is enabled by a centralized planning process, key capabilities like forecasting, inventory planning and materials management, and by better network deployment of materials within the Hydro One network.

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Expected Benefit :
This benefit changed from the original *Post-Discovery Stage, Feb'07 Approved values* as a result of further analysis conducted by the SC team through the course of Design.

Post-Discovery Stage, Feb'07 Approved values:
Cumulative Benefit range (2008-2015):
- $4.35M to $5.87M

Post-Design Stage, Aug'07 Refined values:
Cumulative Benefit range (2008-2015):
- $7.1M to $9.6M

Intangible Benefits: Customer Satisfaction, Regulatory Compliance (Bill 198 etc), Employee satisfaction, Increased Skill and Expertise

Cornerstone key drivers of the benefit:
1. Single, more robust defect management system
2. Greater visibility to committed warehouse materials – confidence that ordered products will be received
3. Forced collaboration in the event of projected stock outs to enable better decision making on roll-out of work

Assumptions and Dependencies:
1. Based on current high level information, it is assumed that there are significant gains to be made with respect to the CMS strategic inventory; however these are not included in the benefit calculation.
2. The aforementioned metric transaction dollars are recorded within the Passport Inventory system and are based on consumable inventory only meaning that we are not counting strategic inventory currently held at CMS. Assumes status quo on Inventory logistics.
3. Ability to train and build the skills for materials planning and inventory management
4. Ability to centralize planning between Barrie, FBCs
5. Deployment of integrated business processes between Supply Chain, Asset Mgt, GO, CO and ECS
6. Extended benefits for Phase 2 will depend on capabilities deployed (assumed 2009).
7. Requires close collaboration with Grid Operations group at CMS to optimized Strategic Inventory. Heavy requirement on Integrated Planning improvements to drive reduction/return rate as key factor resulting in returns is estimating and planning process. Data accuracy will be critical to improve inventory planning and re-order point levels

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2.1.9 (SC3) Improved planning of materials and resources, leading to enhanced field crew productivity

Description: The benefit measures Supply Chain's contribution to crew productivity, by having the right materials available at the right time and the right location. This is enabled by developing a materials classification scheme, providing differentiated service levels, decreasing lead-time violations and increasing order fill rate. In addition, this benefit requires better coordination and integration between the LOBs and Supply Chain. This assumes that the field crews will use the gains in productivity to increase work throughput.

Expected Benefit :
This benefit changed from the original *Post-Discovery Stage, Feb'07 Approved values* because E&CS benefit was increased as a result of further analysis.

Post-Discovery Stage, Feb'07 Approved values:
Cumulative Benefit range (2008-2015):
- $7.67M to $36.48M

Post-Design Stage, Aug'07 Refined values:
Cumulative Benefit range (2008-2015):
- $16.1M to $36.0M

Intangible Benefits: Safety, Customer Satisfaction, Regulatory Compliance (Bill 198 etc), Employee satisfaction, Increased Skill and Expertise

Cornerstone key drivers of the benefit:
1. Material availability and work start time integrated in one system.
2. Earlier visibility of work combined with better integration with supply chain forecasting resulting in advance ordering of long-lead time items.
3. Tighter and more integrated Work and SCM processes.
4. All dependencies known to allow advancement of work where all dependencies are met.

Assumptions and Dependencies:
1. Accurate and timely upstream LOB inputs, an integrated governance module required for SC to meet delivery dates
2. Ability to staff key integration roles in the LOBs and in the Supply Chain organization
3. Substantial improvement in material needs planning across all LOBs. Relies upon successful implementation of Integrated Planning

2.1.10 (SC7) Improve warehouse shipping processes and payment reconciliation with carrier

Description: Automated generation of shipping documents within SAP will lead to better traceability of shipment invoices to shipments planned by Hydro One. It will allow the reconciliation of the carrier invoice with the actual shipment requested.

Expected Benefit:
Cumulative Benefit range (2008-2015): $0.8M - $1.6M

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Intangible Benefits: Improved shipment trail

Assumptions and Dependencies:

- All shipments processed in SAP
- Carrier contracts housed in SAP
- Goods receipt process in service centers in system

2.1.11 (SC8) Improved ERS processes – through better automation

Description: Increase the number of ERS vendors to reduce the number of manual invoices, transaction costs, reconciliation issues and cycle time associated with payments. This is SAP generating an invoice document upon receipt of goods or services through a batch program which will be selected for payment as its payment terms are applied.

Expected Benefit:

Cumulative Benefit range (2008-2015): $5.3M - $7.6M

Intangible Benefits: Fewer mismatched invoices, more discounts taken, fewer late payments

Cornerstone key drivers of the benefit:

1. Receipting performed in a timely manner

Assumptions and Dependencies:

- Increase in # of POs and receipts, becoming more compliant
- Increase in # of receipts entered
- Decrease in open POs
- Decrease in reconciliation time btw PO – invoice
- Decrease in # of paper invoices

2.1.12 (SC12) Greater control governance around one-time setup vs. regular AP vendor setup

Description: Reduce the number of one time vendors and cheque requisitions. The majority of vendors should be set up with a purchase order and a small quantity with just invoices. Greater visibility of spend and therefore ability to analyze spend - both in terms of who's spending and where they're spending (vendors, types of services/materials etc), resulting in greater bill 198 and audit compliance and reduced impact on AP FTE's for ad-hoc requests.

Expected Benefit:

Cumulative Benefit range (2008-2015): $0.4M - $0.6M

Intangible Benefits: Greater bill 198 and audit compliance

Assumptions and Dependencies:

- Increase in contract compliance will reduce number of one-time vendors
- Sufficient training and requisitioner comfort with system requisitioning increases use of preferred and contracted suppliers
- Company policies and procedures in place to support and direct use of preferred and contracted vendors; deterrents in place to reduce use of one-time vendors

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- Centralized vendor master management in sustainment organizations reduces duplicate entry/setup of previously used one-time vendors
- Contracts in place to support unplanned outages; practice to create after-the-fact POs for emerg work
- Annual 3% increase in one-time vendors if not controlled
- Annual incremental 15% improvement in reduction of one-time vendors

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3 Benefits Realization:

The Cornerstone program and Hydro One have acknowledged it is not sufficient to define expected benefits and then proceed with implementation of the solution in the hopes that the benefits will materialize automatically. In order to have a reasonable expectation that Cornerstone Phase 1 will deliver the expected benefits, we must work collaboratively, the lines of business and Cornerstone, to establish a solid foundation of business ownership and an agreed process for best ensuring the realization of Cornerstone's value. To this end, the following next steps are recommended to best ensure Cornerstone Phase 1 VR and to lay a framework or foundation for future phases and major programs.

3.1 During Build/Test/Deploy

Following are the key project steps and deliverables to the Cornerstone Steering Committee to best ensure that benefits will be realized and tracked. The details of the work plan for the next stages of Phase 1 are found in the VR work plans for the Build stage (October 2007 to January 2008), and Test/Deploy Stages (February 2008 to June 2008).

Prior to and throughout the detailed Design stage, the project team will develop and describe the required changes to process, organization, application, culture, by LOB, in order to best realize the anticipated benefits outlined in Section 2 following go-live.

These changes will be developed and described to a level of detail where there are specific actions that can be presented to the Steering Committee.

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Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #32 List 1

Interrogatory

Exhibit E1, Tab 1, Schedule 1, Page 3, Tables 2 and 3

Questions:

a) Provide a version of Table 3 that includes a column for 2007 actuals.

b) Provide a variance report for 2006-2007 in the same format as Table 3.

Response

a. Table 3 cannot be updated for 2007 actuals, as there is no revenue requirement for 2007.

b. See response to part a.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #33 List 1

Interrogatory

References: Exhibit E3, Tab 1, Schedule 1, Page 2, Tables 1 and 2

Questions:

a) Why is the increase in 2008 joint use regulated revenues only $0.2 million given the projected increase in generator connections.

Response

a. Joint use regulated revenues contained in Exhibit E3, Tab 1, Schedule 1, page 2 do not include any revenue from generators.

For details on financial treatment of joint use or line upgrade work that is driven by a generator connection, please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 23. As part of the financial analysis discussed in that response, all costs will be accounted for at the onset of the project and the generator's portion of the cost will be recovered through a capital contribution. Therefore, there are no costs remaining to be recovered from generators through joint use rates, and thus, there are no joint use revenues from them.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #34 List 1

Interrogatory

References: Exhibit E3, Tab 1, Schedule 1, page 6, Table 6

Questions:

a) Explain why no prior year's Late Payment Charge volumes are shown in Table 6. Provide the 2004-2007 volume data and revenues.

b) Provide the basis of the 2008 forecast of $14.5 million and explain any material changes relative to prior years.

Response

a. The volumes of Late Payment Charges were not shown in Table 6 as the data was not available at time of Application. Following is volume data and revenues for years 2004 to 2007:

Year	2004	2005	2006	2007
LPC revenues ($M)	11.4	11.7	12.4	14.2
Number of distinct accounts LPC applied	628,055	634,955	641,805	652,463

b. The 2008 late payment charge revenue forecast of $14.5 million is based on taking the 2007 year-end forecasted revenue, and escalating by expected customer growth in 2008.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #35 List 1

Interrogatory

Reference: Exhibit F1, Tab 1, Schedule 1, page 10

Questions:

a) Provide a breakdown by year of PMO services and costs that CapGemini management function provides for "meter installation and field services".

b) Explain why Hydro One outsourced the services of CapGemini rather than providing the services with internal resources.

c) Please breakdown the services and costs that the PMO function provides for "billing and customer care".

d) Explain why the PMO function for billing and customer care cannot be provided by Hydro One'

Response

a) The PMO provides services to the project across all workstreams and as such cannot be split at a workstream by workstream level. The services provided are explained in the IR response at Exhibit H, Tab 1, Schedule 127, part (k).

b) Please refer to Exhibit H, Tab 1, Schedule 127, part (k).

c) Please refer to Exhibit H, Tab 1, Schedule 127, part (k).

d) Please refer to Exhibit H, Tab 1, Schedule 127, part (k).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #36 List 1

Interrogatory

References: Exhibit F1Tab 1 Schedule 1 Page 11 Table 7

Questions:

a) Why is HO seeking recovery of under-recovery of SM costs for minimum functionality from June 1 2007-April 30, 2008?

b) Provide a breakdown of the Total SM actual costs and revenue requirement at May 1 2007, December 31, 2007 and forecast May 1, 2008 in the same format as used in the SM Combined Hearing. (includes Units and capital and Operating costs for meters and AMCD/AMRC etc.)

c) Relate the under-recovery amounts in Tables 5 and 7 to the Total Cost. Please provide the calculations of the revenue requirement amounts of $6.1 million, $10.6 million, and $11.7 million for December 31, 2006, December 31, 2007, and April 30, 2008, respectively.

d) Provide details of SM main account 1555 – smart meter capital and recovery offset variance account, and main account 1556 – smart meter OM&A variance account in 2007 and for 2008. Show details of subaccounts and balances under accounts 1555 and 1556.

e) Provide Details of Interest calculations for Accounts 1555 and 1556 and subaccounts at May 1, 2007, December 31, 2007 and May 1, 2008.

Response

a. Hydro One believes it is appropriate to recover all smart meter costs for the period up to inclusion of the costs in rate base and revenue requirement (ie. May 1, 2008).

b. See the response to H-10-28 for a breakdown of the costs. Corresponding cumulative revenue requirements (net of recoveries) are shown in the following table:

$ millions	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Smart Meter Minimum Functionality Under-recovery to May 31, 2007	3.6	5.8	7.0
Smart Meter Exceeding Minimum Functionality Under-recovery	0.6	1.1	3.5
Smart Meter Minimum Functionality Under-recovery between June 1, 2007 and April 30, 2008	0.0	(1.0)	1.6
Total	**4.2**	**5.9**	**12.1**

c. See response to H-1-120a.

d. Hydro One does not track detailed expenditures in accounts 1555 and 1556 (see response to H-1-128c). A breakdown of the costs is provided in the response to part b above.

e. See response to H-1-128f.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #37 List 1

Interrogatory

Reference: Exhibit G1, Tab 1, Schedule 1, page 3, lines 3-7

Question:

a) The referenced text suggests that there are no customers within any of the 88 Acquired Utilities that meet the definition for the R2 Residential (Low Density) class. Please reconcile this with proposed treatment of Caledon's customers (Exhibit G1, Tab 2, Schedule 3, page 3).

Response

The referenced text in Exhibit G1, Tab 1, Schedule 1, provides a generalized description.

Caledon has 4 different Residential customer classes. Exhibit G2, Tab 18, Schedule 2, describes Caledon's current customer classes. Caledon Residential OH-06 includes customers that were originally R2 customers in Ontario Hydro. Caledon Residential OH-07 includes customers that were originally R4 customers in Ontario Hydro. The above information was included in Exhibit G1, Tab 2, Schedule 3, pages 3 and 4, describing the number of customers proposed for the new R2 and Seasonal customer classes.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #38 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 1, page 1, lines 9-23

Preamble: *Elsewhere in its Application Hydro One Networks states (Exhibit G1, Tab 2, Schedule 2, page 1) it has three basic customer groups:*

- *Legacy Retail Customers*
- *Acquired Utility Customers and*
- *Embedded Customers*

Question:

a) Please describe if and how the current characterization of Hydro One's customer groups provided in Schedule 1 differs from the customer classes described in Schedule 2.

b) Please provide a "definition" for Hydro One's current Embedded (LV) customer class.

c) Please provide a schedule that sets out the various delivery voltages for Hydro One's current Embedded (LV) customers and the number of "Embedded" customers served at each voltage. Furthermore, please report the numbers for Directs and LDCs separately.

d) Does Hydro One Networks currently have (or expect to have prior to April 30, 2009) any distributed generators as customers who would be considered "Embedded" customers? If so, how many and at what voltages are they connected?

e) Please provide a definition of Hydro One's "Sub-Transmission (ST) system" as used on page 1, line 19.

f) Please clarify how the 500 kW is applied for purposes of the proposed customer classification definition of Sub-Transmission. For example, is it meant to represent the customer's maximum monthly demand or the customer's average monthly demand?

g) Please clarify how the 50 kW is applied for purposes of customer classification (per Exhibit G1, Tab 2, Schedule, page 6). For example, is it meant to represent the customer's maximum monthly demand or the customer's average monthly demand?

h) Is this definition for the 500 kW demarcation (per part (f)) consistent with that used for the 50 kW demarcation (per part (g))? If not, why not?

i) Does Hydro One have any large customers with demands over 500 kW (per lines 21-22) that do not provide their own transformation? If so please provide a schedule that indicates how many there are broken down by current customer class and delivery voltage.

j) Does Hydro One have any customers with demands under 500 kW that provide their own transformation facilities? If so please provide a schedule that indicates how many there are broken down by current customer class and delivery voltage.

k) Is the 500 kW value used at all in the current definitions of Hydro One's customer classes? If so, please indicate where.

l) Please explain the rationale for using 500 kW as the demarcation point for ST customers.

m) Please explain why the definition for the ST system uses 13.8 kV as the demarcation point as opposed to say higher (e.g. 27.6 kV) or lower voltage (e.g. 8.32 kV).

n) Are there any customers that are directly connected to Hydro One facilities at voltages of 13.8 kV or higher that have demands of less than 500 kW?

o) Please provide a schedule that sets out delivery voltages for Hydro One's current Legacy Retail customers (including Transmission customers) and indicate the number of customers served at each voltage by customer class. (Note: For purpose of the response, all customers served at less than 750 volts can be grouped together).

p) Please provide a schedule that sets out delivery voltages for Hydro One's current Acquired Utility customers (including Large Use customers) and indicate the number of customers served at each voltage by customer class. (Note: For purpose of the response, all customers served at less than 750 volts can be grouped together).

Response

a. Schedule 1 actually describes customers in both the current and proposed context. There is no inconsistency in customer group description between Schedules 1 and 2.

b. Hydro One's current Embedded (LV) class includes all LDCs, plus end-use customer locations that have been classified as Direct, that is, customers with average annual monthly consumption over 5 MW located in Hydro One's Legacy service areas.

c.

LDCs:

# of LDCs	supplied at voltage(s) (kV)
1	44 & 27.6 & 12.5
3	44 & 27.6 & 8.32
5	44 & 27.6
1	44 & 22
3	44 & 12.5
8	44 & 8.32
11	27.6 & 8.32
15	44 only
10	27.6 only
3	24.9 only
2	13.8 only
4	12.5 only
3	8.32 only

Directs:

# of Directs	supplied at voltage(s) (kV)
1	44 & 27.6
17	44 only
11	27.6 only
1	24.9 only
2	13.8 only

d. Hydro One expects to connect 4 large, 40 mid-size and 20 small generators in 2008 and a similar volume is expected for connection in 2009. Most if not all in the large and mid-size categories are likely to be connected at 44kV or 27.6kV.

e. Hydro One's "Sub-Transmission (ST) system" as described in Exhibit G1, Tab 2, Schedule 1, page 1, line 19 is: three-phase assets between 44 kV and 13.8 kV

inclusive; HVDS-highs are included, and for supply to LDCs at 12.5 kV and lower, HVDS-lows and LVDS-lows.

f. The 500 kW criterion is the annual average of the maximum monthly demand.

g. The 50 kW criterion is the annual average of the maximum monthly demand.

h. Yes, both criteria are the annual average of the maximum monthly demand.

i. Hydro One's estimate of the number of customers who do not own their own transformation and who are over 500 kW is 77. Hydro One does not have the breakdown by delivery voltage. The breakdown by rate class is in the table below.

Class	#
F3	4
G3	28
GS (acq'd)	23
T	12
UG	10
sum	77

j. Hydro One's estimate of the number of customers who own their own transformation and who are under 500 kW is 403. Hydro One does not have the breakdown by delivery voltage. The breakdown by rate class is in the table below.

Class	#
F3	4
G1	30
G3	120
GS (acq'd)	141
T	94
UG	14
sum	403

k. No, the 500 kW value is not used in current definitions of Hydro One's customer classes.

l. Hydro One Networks' policy is that the maximum padmount transformer size it supplies is 500 kVA, and the maximum overhead (polemount) transformer size it supplies is 501 kVA. Customers would supply and own transformers larger than 500 kVA.

500 kVA is also the threshold used in determining at what voltage customers should be connected. At 500 kVA or higher, a sub-transmission voltage connection is required, e.g. 13.8 kV to 44 kV.

m. There is only one stage of transformation whose high voltage side is lower than Transmission* voltage and whose low voltage side is higher than Secondary** voltage: the "LVDS" stage. In Hydro One's Distribution system, feeders at 12.5 kV and below are extremely likely to be supplied by an LVDS, and feeders at 13.8 kV and above are extremely likely to not be supplied by an LVDS. This extra stage of transformation makes a good demarcation point.

Also, for a customer to be in the ST class, Hydro One would not own any local transformation (transformation to a Secondary voltage). Hydro One Networks' policy is that the maximum transformer size it supplies is 500 kVA. Customers would supply and own transformers larger than that. Hydro One Networks' policy is also that service sizes over 500 kVA are to be supplied at 13.8 kV and above. This is an additional reason for the voltage demarcation point to separate 13.8 kV and above from 12.5 kV and below.
Also, 13.8 kV is the lowest voltage supplying a Direct customer.
* Transmission voltage is above 50 kV
** Secondary voltage is under 750 V

n. Yes, there are some, for example those customers whose load has declined below 500 kW, and those who chose to have a non-standard transformer, which would mean that the customer, not Hydro One, would own the transformer.

o. Hydro One does not have this detailed information readily available. For cost allocation purposes, Hydro One has assumed that all demand billed customers are served from the Primary system and all energy billed customers are served from the Secondary system

p. Hydro One does not have this detailed information readily available. For cost allocation purposes, Hydro One has assumed that all demand billed customers are served from the Primary system and all energy billed customers are served from the Secondary system

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #39 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 2, pages 2-4

Question:

a) With respect to the current Farm class, at what voltages are single phase vs. threephase customers served?

b) With respect to the GS class, at what voltages are single phase vs. three phase customers served?

c) Please provide the definition of the "sub-transmission" system used for purposes of currently identifying existing "Transmission" Customers per page 4.

d) Are there any Residential or Farm customers currently served off the subtransmission system? If so, please indicate how many of each. Please also confirm whether these customers are charged Residential/Farm rates or LV rates.

Response

a. If Hydro One owns the local transformer, the customer is served at one of a range of possible voltages under 750 V. If Hydro One does not own the local transformer, the customer is served at the feeder voltage, which could range from 27.6 kV three-phase to 2.4 kV single-phase.

b. Same as "a" above

c. Hydro One's existing Conditions of Service document, in the Glossary of Terms, states that "Sub-transmission System" means a system related to the Distribution of electricity supplied at voltages above 13 kV, 3 wire but less than 50 kV, 3 wire".

d. The existing definition of the subtransmission system (as in "c" above) is different than the proposed definition.

Based on the existing definition, no Residential or Farm customers have the local transformer connected to the subtransmission system.

Based on the proposed definition, many Residential and Farm customers have the local transformer connected to the subtransmission system. Few or no Residential

customers, and few Farm customers, would own the local transformer; ownership makes the voltage at which they are served, the feeder voltage.

Residential customers are charged Residential rates. Farm customers are charged Farm rates.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #40 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 2, page 5

Question:

a) How are Low Use Secondary Services treated by Hydro One for purposes of Cost Allocation:
- Are they considered a separate customer? If so, please explain why.
- Are they considered a separate connection? If so, please explain why.

b) How many of the 2,500 customers fall into each of the following classes: Residential Year-Round, Residential Seasonal, Farm and General Service?

Response

a. The existing Low Use Secondary consumption and customer counts have been included with the GSe rate class. The reason being that the bulk of these customers currently pay the General Service variable rate plus a historical 13 mils adders. Since nearly 95% of the customers [exclude Farms] are on the General Service Rate, it was decided to harmonize them with the GSe rate class. Also, these accounts do not reflect residential type consumption.

b. The estimated 2,500 accounts for 2007 reflect the fact that some low use customers exceeded the thresholds and have since been removed from the subclass. The 2007 statistics by Rate Class are not currently available. The statistics for 2006 are presented below:

Year Round Residential	2,148
Seasonal Residential	443
Farms	215
General Service	319
Total	3,125

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #41 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 2, Schedule 3, pages 2-7
ii) Exhibit G2, Tab 3, Schedule 1

Question:

a) Please confirm that there were no former R2 Legacy customers that were reclassified as R1. If there were, please revise Table 2 accordingly.

b) If part (a) is confirmed, please indicate whether or not a comprehensive review was done of R2 Legacy customers to see if any qualified for R1 status. If no such review was done, please explain why.

c) Please provide a schedule that shows for each of the 88 Acquired Utilities, the split of current Residential customers between the new Urban and R1 customer classes. Note: For Caledon please also include R2.

d) What are the current criteria that a customer must meet to qualify for RRRP (per page 3, lines 8-9)?

e) Will any of the Acquired Utilities customers (e.g. Caledon customers) reclassified as R2 qualify for RRRP? If not, why not?

f) The text suggests that all energy billed Farm customers were reclassified as R2 Residential (per page 3, lines 7-8). Is this correct? If so:
- Do all current energy billed Farm customers fall in the R2 density zone?
- Do all current energy billed Farm customers qualify for RRRP?
- Do all current energy-billed Farm customers meet the definition of a Residential customer as set out at Exhibit G2, Tab 5, Schedule 1, pages 2-3? If not, how many do not and why are they reclassified as R2?

Response

a. Confirmed, no former R2 Legacy customers have been density reclassified as R1.

b. No study was done to determine if R2 Legacy customers qualify for R1 status. It was decided to wait for when better customer connectivity and lines detail is available in our GIS system to do a full Density Review of Hydro One Distribution's entire service territory. With existing data and resources, it was decided an Urban review of high density areas could be accomplished and was undertaken.

c. The decomposition of the residential customers of the Acquired Distributors is listed below based on 2006 Active year end customer counts.

Distributor	**Urban**	**R1**	**R2**
Ailsa Craig	-	348	
Arkona	-	217	
Arnprior	2,848	286	
Arran-Elderslie	-	1,675	
Artemesia	-	412	
Bancroft	-	1,001	
Bath	-	737	
Blandford-Blenheim	-	838	
Blyth	-	382	
Bobcaygeon	-	1,641	
Brighton	-	2,320	
Brockville	8,146	192	
Caledon OH 01	8,794	-	
Caledon CH 02	-	2,118	
Caledon OH 06	-	-	7,266
Campbellford-Seymour	-	1,427	
Carleton Place	3,618	93	
Cavan-Millbrook-North Monaghan	-	560	
Centre Hastings	-	647	
Chalk River	-	376	
Champlain	-	1,715	
Cobden	-	469	
Deep River	-	1,741	
Deseronto	-	664	
Dryden	2,526	108	
Dundalk	-	687	
Durham	-	1,110	
Eganville	-	545	
Erin	-	904	
Exeter	-	1,986	
Fenelon Falls	-	970	
Forest	-	1,167	

GBE	7,638	195	
Georgina	-	1,132	
Glencoe	-	850	
Grand Bend	-	1,038	
Hastings	-	503	
Havelock	-	510	
Kirkfield	-	107	
Lanark Highlands	-	337	
Larder Lake	-	383	
Latchford	-	186	
Lindsay	6,347	167	
Lucan Granton	-	850	
Malahide	-	243	
Mapleton	-	722	
Markdale	-	632	
Marmora	-	579	
McGarry	-	297	
Meaford	-	2,026	
Middlesex Centre	-	398	
Napanee	-	2,036	
Nipigon	-	728	
North Dorchester	-	713	
North Dundas	-	1,509	
North Glengarry	-	1,901	
North Grenville	-	1,359	
North Perth	-	2,416	
North Stormont	-	335	
Omemee	-	506	
Perth	2,745	100	
Perth East	-	548	
Prince Edward	-	3,092	
Quinte West	5,657	1,005	
Rainy River	-	378	
Ramara	-	99	
Red Rock	-	354	
Rockland	-	3,536	
Russell	-	847	
Schreiber	-	593	
Severn	-	577	
Shelburne	-	1,703	
Smiths Falls	3,637	99	
South Glengarry	-	440	
South River	-	473	
Springwater	-	735	
Stirling-Rawdon	-	808	
Thedford	-	295	

Thessalon	-	550	
Thorndale	-	134	
Thorold	5,963	1,139	
Tweed	-	660	
Wardsville	-	143	
Warkworth	-	258	
West Elgin	-	989	
Whitchurch Stouffville	3,228	66	
Wiarton	-	893	
Woodville	-	320	
Wyoming	-	829	
Terrace Bay		1,025	
Totals	61,147	72,682	7,266

d. The criteria that the customer must meet is to have received RRRP before market opening. The criteria for applying RRRP was established before market opening. Our rate classes of R2 and Farm (where there is a residence on the property) receive the RRRP credit.

e. Yes, the entire R2 rate class receives the RRRP credit including the Caledon customers mapped to R2.

f. No, only energy-billed farms with RRRP are being consolidated in the new R2 rate class.

Not all energy-billed farms fall into R2 Rate Class. Some have been identified as being in an Urban density zone and they will be moving to UR or UGe.

Not all energy-billed farms qualify for the RRRP credit.

The energy-billed farms with RRRP who are being mapped to R2 will meet the Residential criteria since they must be residential to receive the RRRP credit.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #42 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 3, page 7

Question:

a) Please provide the specific EB-2005-0528 reference.

b) Do all the 48 distributed generators currently classified as T-Class have loads in excess of 500 kW? (Note: Please use the same "definition" for 500 kW as defined in response to Question #2.)

c) Are all of the 32 Distributed generators currently classified as GS-three phase demand billed? If not, how are they currently classified?

d) Please provide a schedule that breaks down the 32 Distributed Generators (currently service on GS rates) by service voltage. Please also include in the schedule the one acquired GS customer.

e) How does Hydro One determine that a customer with a generator will be classified as a "distributed generator" customer as a opposed to being classified to one of the other customer classes?

f) Why has Hydro One created only one "Distributed Generator" customer class as opposed to two – one for ST connected customers and one for lower voltage connected customers?

g) How many Sentinel Light customers were there in 2006?

h) How many Sentinel Light customers in 2006 were also billed for service under another customer classification? Please provide a breakdown.

i) For the customers identified in response to part (h):
- How many were billed for Sentinel Light service using the same bill as for their other service?
- How many received their Sentinel Light service from the same connection point as their other service?
- For purposes of Cost Allocation, were these Sentinel Light customers considered as a separate customer and/or connection? Please explain why.

Response

a. On page 5 of the Decision, it states that:
"Although the Board believes there is merit in considering the Company's proposal for a volumetric only rate for distributed generator customers, it cannot be considered in the absence of supporting detailed cost and benefit information. The Board believes that the cost allocation process currently underway with the Board and industry stakeholders is the appropriate process for determining the underlying costs for distributed generators. The Board therefore directs the Company as part of its upcoming cost allocation review filing to properly identify the costs for serving the proposed new rate classification(s)…."

b. No, only 2 of the current T-Class distributed generator have an average monthly kW demand exceeding 500 kWs. (The reference in the question could not be found).

c. No, some of the three phase General Service distributed generators are energy-billed.

d. No customer connectivity by service voltage is readily available for these customers.

e. Only merchant generators qualify for this rate class. Further, micro-generators [<10 kW] are not included in this rate class.

f. Only one DGen rate class was created in an effort to reduce rate classes.

g. There were approximately 38,750 Sentinel Light accounts in 2006.

h. Over 96% of unmetered sentinel lights are associated with a main electric account to get their billing. The composition is listed below:

Residential	15,686
Seasonal	1,025
Farms	4,573
General Service	7,879
Lights	1,246
Total	30,409

i. Referring to Part h statistics
   a. 96% of the accounts get the Sentinel Light bill on the main electric account bill
   b. Virtually all sentinel lights use the same service point connection as the main electric account
   c. For the Cost Allocation, the Sentinel Lights customers were treated as a separate account. This is because typically each sentinel light account is

associated with a main electric account and imposes fixed costs on distributors like an individual customer.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #43 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 3, pages 8 - 9

Question:

a) How many embedded LDCs have service points where the connection is at less than 13.8 kV?

b) How many delivery points for these LDCs are at less than 13.8 kV?

c) How many of these LDCs are only served by Hydro One distribution at voltages of less than 13.8 kV?

d) Please provide a schedule that breaks down both the number of ST cutomer delivery points by delivery voltage.

Response

a. 33 embedded LDCs have service points where the connection is at less than 13.8 kV.

b. 78 delivery points for these LDCs are at less than 13.8 kV.

c. 7 of these LDCs are served by Hydro One Distribution at voltages only of less than 13.8 kV.

d. The number of ST delivery points by voltage is:

kV	#
44	345
27.6	219
24.9	16
22	4
13.8	8
12.5	21
8.32	57
Total	670

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #44 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 2, Schedule 4
ii) Exhibit G2, Tab 3, Schedule 1, page 3

Question:

a) Who should a customers contact if they believe their density classification is incorrect?

b) What process has Hydro One established to address queries by either individual customers or local municipalities that their density classification is incorrect?

c) Page 3 of Reference (ii) provides a list of communities analyzed under the density review. How was the density classification of customers in the other acquired utilities established?

Response

a. Customers should contact the Hydro One Customer Communications Centre, if they have a question regarding their rate classification. The Centre's number is printed on the customer's bill. (1-888-664-9376.)

b. The Hydro One process in response to density classification customer inquiries is for our Customer Communications Centre representatives to issue an investigation order to our field staff. The rate will be checked by our field staff and the customer will be informed via letter of the results of the investigation. If the account meets the criteria for a different density rate, the rate will be changed on their bill going forward. If the account does not meet the criteria, then the billing rate will remain the same.

c. Please see Exhibit H, Tab 1, Schedule 134.
Per Acquired Distributor, the customer counts and customer per line kilometre metrics were analyzed. Since the non-urban Acquired Distributors have at least 100 customers with a line density of at least 15 customer per km, they all meet the requirements for the Medium Density Zone.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #45 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 5, Table 1

Question:

a) Table 1 suggests that there is no Acquired Utility for which all of its residential customers were reclassified as Urban Residential (i.e., all 88 are affected by R1). Please confirm that this is the case.

Response

Yes, no single Acquired Distributor is mapped 100% into Urban. Some customers were mapped into the Rural R1 rate class as they met the 60 customer per km metric.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #46 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 2, Schedule 5, page 5
ii) Exhibit G1, Tab 4, Schedule 2, pages 1-2

Question:

a) Is the range of fixed charges provided for R2 Residential (Reference (ii), Table 1) before or after the application of RRRP?

b) On page 1 of Reference (ii) it states that Hydro One is proposing to introduce a nominal service charge for Street and Sentinel Lights of $1 / account / month. However, on page 2 of the same reference the footnote to Table 1 states the charge is per connection. Please reconcile.

c) Please provide the approved Street and Sentinel Light rates for other LDCs that Hydro One considered in drawing its conclusion that $1 / account / month was consistent with the charges of other LDCs for this type of service (per Reference (ii)).

Response

a. The fixed charges for R2 are gross rates. That is, they are before the RRRP credit.

b. The second reference should read as per account.

c. The table below includes some examples of 2007 fixed charges

Fixed Charges $/connection	Toronto	Powerstream	Veridian	Ottawa	Horizon
Street Light	0.26	0.60	0.79	0.32	0.36
Sentinel Light		2.68	2.58	1.68	1.59

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #47 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 5, pages 7- 9

Question:

a) Please confirm whether the results set out in Table 3 are based on:
• The first year's results of the four year implementation plan, or
• The results assuming the harmonization was accomplished in one year.

b) If the response to part (a) is that its represents the impact of harmonization in one year, please re-do Table 3 based on the 2008 results expected from the four year implementation plan.

c) Do the impacts set out in Table 3 include the changes in Rate Riders proposed for 2008? If not, please re-do Table 3 to reflect both the impact of the proposed change in rate riders for 2008 and (if necessary) the first year of the four year harmonization plan.

d) With respect to page 9 (lines 16-18), please clarify what is meant by the statement that "all Acquired customers would, on average, have a total yearly bill of less than 10%, including the impact of the 2008 revenue requirement increase".

e) Does the statement referenced in part (e) also include the impact of the proposed changes in the rate riders? If not, please indicate the impact of including the changes proposed to the rate riders.

Response

a. The impacts presented in Exhibit G1 Tab 2 Schedule 5 Table 3 are at the end of the 4 year implementation plan. This can also be described as assuming the harmonization is accomplished in one year

b. The impact ranges for 2008: the first year of the proposed 4 year implementation plan are:

Residential	2.2 to 9.7%
General Service	0 to 8.9%

c. The impacts are inclusive of the changes in Rate Riders proposed for 2008.

d. The paragraph is stating that the 2008 total bill increase for an average Acquired customer will be limited to 10% inclusive of the harmonization impacts, regulatory rate rider changes, Retail Transmission Service rate changes, loss factor changes and the increased Distribution Revenue Requirement.

e. The reference is assumed to refer to part d not e. Assuming that the reference is to part d, the answer is the 10% limit is inclusive of the proposed Rate Riders for 2008.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #48 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 6

Question:

a) Please explain why the fixed monthly service charge for General Service – Energy Billed is the appropriate rate to apply. It is noted that many of these customers are associated with Residential accounts (Exhibit G1, Tab 2, Schedule 2, page 5).

Response

Please see Exhibit H, Tab 12, Schedule 40. The majority of main accounts which have Low Use Secondary service are Residential but the rate the Low Use Secondary is actually being charged is the General Service energy rate with a 13 mils adder. Since they are being charged the General Service variable rate for this separate service, the new proposed Service Charge is the General Service energy-billed Service Charge.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #49 List 1

Interrogatory

Reference: Exhibit G1, Tab 3, Schedule 1, pages 1-2

Question:

a) Please confirm that the $1,067 M revenue requirement is prior to any allowance for $42 M in external revenues and that the revenues required from 2008 distribution rates are $1,024.3 M (after allowances for rounding). If not, please explain why.

b) Exhibit G2, Tab 1, Schedule 1 (page 5) states that the $1,067 M already includes the cost of Transformer Ownership Allowance. Please indicate where in the Application this "cost" was described and included in the work-up of the $1,067 M.

c) Please provide a schedule setting out the details of the adjustment process outlined on page 1 (lines 23-28). In doing so please show:
- The 2007 revenues by customer class prior to any adjustment and clarify whether the revenues are net of the transformer ownership allowance.
- How the $42 M in external revenues were accounted for in the adjustment.

Response

a. The $1067 M is the total Hydro One Distribution Revenue Requirement before any allowance for external revenues of $42.3M. The resultant distribution rates revenue is $1024.3M.

b. The statement in Exhibit G2, Tab 1, Schedule 1, page 5 is not correct. The costs have not been included in the $1,076 M. Hydro One will address the cost of the transformer ownership allowance as a rate design adjustment, like the credit for unmetered scattered load that is recovered from all General Service energy billed customers. The evidence has been updated to reflect the recovery of the costs of the allowance from General Service demand billed and DGen customer classes. The impacts shown in the evidence have not been updated, because the impact is negligible, about 0.2% on the total bill.

c. The Revenue Requirement adjustment process is summarized below:

- Used the 2008 Sales Forecast by rate class
- Multiply by 2007 existing rates

- Escalate the existing rates to achieve distribution rates revenue of $1024.3M.
- The $42.3M of External Revenues is not included in the adjustment

		2008 Stats @ 2007 Rates	2008 Stats @ Adj 2007 Rates
UR		$ 51.2	$ 53.9
R1		$ 174.9	$ 186.5
R2		$ 365.5	$ 392.6
Seasonal		$ 69.6	$ 74.8
UGe		$ 11.0	$ 11.6
UGd		$ 14.8	$ 15.7
GSe		$ 106.6	$ 113.9
GSd		$ 98.8	$ 105.5
DGen		$ 0.6	$ 0.6
ST		$ 61.3	$ 63.4
St Lgt		$ 4.8	$ 4.8
Sen Lgt		$ 0.9	$ 0.9
$ Millions		$ 960.0	$ 1,024.3

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #50 List 1

Interrogatory

Reference: Exhibit G1, Tab 3, Schedule 1, pages 2-4

Question:

a) How many of the customers in Hydro One's ST class have average monthly peak demands in excess of 5,000 kW?

b) Why is it appropriate to apply the +/- 15% range adopted by the OEB for the Large User class to Hydro One's Sub-Transmission class?

c) What would be the revenue to cost ratio for the ST class if, rather than not recovering $2.5 M of the 2008 Revenue Requirement (per page 4), the rates for the ST class were increased to recover the $2.5 M.

d) Is it Hydro One's view that the OEB requires LDCs to move their revenue to cost ratios to within the ranges provided in its November 27, 2007 Report as part of their 2008 Rate Applications? If yes, where is this direction explicitly provided?

e) Please provide a Schedule that sets out the revenues to be recovered through 2008 distribution rates for each customer class based on Hydro One's proposed target revenue to cost ratios. Note: This is different from Table 2 which shows total Revenue Requirement including the allocation of Miscellaneous Revenues,

Response

a. 107 customers in Hydro One's ST class have "annual average of monthly peak demands" over 5,000 kW.

b. The new ST class includes all Direct customer and all Large Users. These customers have consumption above 5,000 kW. The ST class also includes all Embedded Distributors. Currently Embedded Distributors and Direct customers are charged the OEB approved Low Voltage rates. Directs, Large Users, and Embedded LDCs make up the majority of the consumption in the new ST class. Hydro One considers these customers to fit the OEB description of large users in the November 27, 2007 OEB report on recommended revenue to cost ratios resulting from the application of the results of the cost allocation study.

c. If the revenue shortfall of $2.5 million would be recovered from the ST class, the revised ST class revenue to cost ratio would be 1.24.

d. Please see Exhibit H, Tab 11, Schedule 30, part c.

e. The table below sets out the 2008 proposed Rate Class revenue requirements based on the proposed Revenue-to-Cost Ratios. The 2008 Revenue Requirement is $2.47M lower than the target of $1066.6M

	2008 Revenue Requirement	**Misc Revenues**	**2008 Rates Revenue**
UR	$ 65.95	$ 3.82	$ 62.13
R1	$ 211.37	$ 10.63	$ 200.74
R2	$ 404.61	$ 11.96	$ 392.65
Seasonal	$ 83.60	$ 2.15	$ 81.45
GSe	$ 119.59	$ 5.67	$ 113.92
GSd	$ 107.88	$ 2.35	$ 105.53
UGe	$ 11.21	$ 0.47	$ 10.74
UGd	$ 16.81	$ 0.33	$ 16.48
St Lgt	$ 5.68	$ 0.11	$ 5.57
Sen Lgt	$ 5.57	$ 4.03	$ 1.54
Dgen	$ 0.39	$ 0.00	$ 0.38
ST	$ 31.45	$ 0.76	$ 30.70
	$ 1,064.11	$ 42.30	$ 1,021.81

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #51 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 4, Schedule 1, pages 1-3
ii) Exhibit G1, Tab 4, Schedule 4, pages 3-4

Question:

a) The Reference (i) defines HVDS as providing transformation service from above to under 50 kV. However, Reference (ii) states that HVDS only provides stepdown to 44 kV and 13.8 kV. Please clarify which definition is correct.

b) The two definitions in Reference (i) relating to Low Voltage Distribution Stations are inconsistent with the definitions provided at lines 10-20 on page 3 of Reference (ii). Please reconcile.

c) What are the voltages of the common lines describe in Reference (i) at page 2, line 19 and what is the definition of a "common line"? Do they include both ST lines and primary lines?

d) Please provide a schedule that sets out:
- The current (2007) gross fixed charge for the R2 Residential class and the monthly RRRP amount
- The proposed (2008) gross fixed charge for the R2 Residential class and the (proposed) monthly RRRP amount.

e) How is the proposed monthly RRRP amount determined? For example:
- Is there a fixed pool of RRRP dollars that are divided equally between all qualifying customers? or
- Is the per customer RRRP discount fixed at some amount (if so please describe how) and applied to all qualifying customers?

Response

a. The first reference is a generic description. The second reference is more detailed. Reference (ii) does not state that HVDS only provides step-down to 44 kV and 13.8 kV. Reference (ii) states that HVDS-highs transform from above 50 kV to a voltage between 44 kV and 13.8 kV, and that HVDS-lows supply voltage at or below 12.5 kV.

b. For further clarity, the descriptions in reference (i) on page 2, lines 20 to 25, refer to:

- Volumetric charge for the use of those High Voltage Distribution Stations which provide transformation service from above 50 kV to a voltage between 44 kV and 13.8 kV
- Volumetric charge for the use of those High Voltage Distribution Stations which provide transformation service from above 50 kV to a voltage of 12.5 kV or lower
- Volumetric charge for the use of those Low Voltage Distribution Stations which provide transformation service from below 50 kV to a voltage of 12.5 kV or lower

c. The voltages of the reference's common lines are 44 kV to 13.8 kV, plus a small amount at under 13.8 kV supplying LDCs.
The Common Line rate would be applied when Distribution line (not including Specific* line sections) is used to supply an ST customer. It is very analogous to the Shared Line rate application.
They are almost totally ST lines. The only Primary Lines included are the small lengths of Primary line supplying LDCs at under 13.8 kV.

* A Specific Line section lies within the supplied LDC and carry electricity solely for that supplied LDC

d. The following table outlines the R2 rate class existing and proposed 2008 Service Charge and RRRP Credit amount.

	Gross Fixed Charge	RRRP Credit
Current (2007)	$57.72	$28.50
Proposed (2008)	$55.55	$28.50

e. The RRRP Credit for the R2 class is the historical amount of $28.50 which is applicable to all customers.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #52 List 1

Interrogatory

Reference: Exhibit G1, Tab 4, Schedule 2, pages 1-2

Question:

a) Please provide the results for each of the three methods for determining fixed charges as applied to each of the customer classes proposed by Hydro One, using the 2008 cost allocation.

b) Please confirm that the proposed fixed charges for UGe and GSe shown in Table 1 are prior to any increase to recover the USL revenue shortfall discussed on page 2, lines 8-13.

c) Is the calculation of the fixed charge range for Street Lights and Sentinel Lights and the results shown in Table 1, done on a per account or per connection basis?

Response

a. The Service Charge scenarios can be found in Exhibit G2, Tab 1, Schedule 1, Attachment A, page 37 of Cost Allocation Model's output sheet labelled O2: Fixed Charge|Floor|Ceiling. The results have been represented in the table below.

	Avoided Cost	Directly Related	Min System with PLCC
UR	$ 8.47	$ 10.69	$ 22.12
R1	$ 8.56	$ 10.89	$ 29.67
R2	$ 9.41	$ 12.07	$ 45.37
Seasonal	$ 6.34	$ 7.82	$ 30.58
GSe	$ 10.72	$ 13.91	$ 30.97
GSd	$ 26.49	$ 37.79	$ 54.46
St Lgt	$ 5.01	$ 6.46	$ 12.40
Sen Lgt	$ 2.36	$ 2.86	$ 32.77
Dgen	$ 25.26	$ 30.85	$ 36.66
ST	$ 192.71	$ 244.33	$ 372.12
UGe	$ 10.73	$ 14.02	$ 12.33
UGd	$ 29.19	$ 40.26	$ 39.65

b. Yes, the rates presented in Table 1 of Exhibit G1, Tab 4, Schedule 2, are before any adjustment for USL metering credits.

c. In the Cost Allocation Model, accounts were used for Street Lights and Connections x 10% was used for Sentinel Lights. The 10% factor is consistent with the default Billing weights for Sentinel Lights.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 4, Schedule 3, page 1, lines 21-22
ii) Exhibit G1, Tab 7, Schedule 1, page 1, lines 3-5
iii) Exhibit G1, Tab 8, Schedule 2, pages 1-4

Question:

a) Please explain what is meant by "total average bill impacts" (per References (i) and (ii)). Is this meant to be:
- The average bill impact for all customers in the class?
- The bill impact for an average customer?

b) If the response to (a) is the bill impact for an average customer – please provide the consumption characteristics assumed for the average customer in each of Hydro One's proposed customer classes.

Response

a. The term "total average bill impacts" refers to the projected bill impact for an average customer per rate class.

b. The average consumption per rate used in the Bill Impact analysis is contained in the table below. The numerous levels of DGen are presented since the average was narrowed to sub-groups.

		kWh	kW	Load Factor
UR		1,000		
R1		1,000		
R2		1,000		
Seasonal		400		
GSe		2,000		
GSd		43,164	133	45%
UGe		2,000		
UGd		43,164	133	45%
St Lgt		1,440		
Sen Lgt		62		
Dgen	D-Billed G3	35,000	90	54%
	D-Billed T	7,700	200	5%
	E-Billed G3	802	8	14%
	E-Billed T	846	26	5%
	Acquireds	6	1	1%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #54 List 1

Interrogatory

Reference: Exhibit G1, Tab 4, Schedule 4, page 4

Preamble: *The discussion on page 4 regarding the fixed charge states:*

- *The $188 charge is based on the OEB Cost Allocation method c) of determining fixed charges (lines 19-20)*
- *This value ($188) is lower than the fixed charge that would be determined using the fixed Revenue Requirement estimated by the Cost Allocation Methodology (lines 17-19)*

Question:

a) If the proposed $188 is based on Method c) and it is Method c) that produces the upper end of the fixed charge range prescribed by the OEB, why is the proposed value lower than the fixed charge that would be determined using the Cost Allocation Methodology?

b) The text on page 4 (lines 12-13) indicates those cases where a fixed charge will apply:
   i. Are there specific ST customer delivery points that do not fit either of the "cases" described and will not be assessed a fixed charge?
   ii. If so, how many delivery points are there in total and how many will not attract a fixed charge?
   iii. If so, why is the fixed charge not applied to all delivery points?

c) For purposes of the Cost Allocation Methodology are customer-related costs allocated to ST customers on a per account basis (e.g., each embedded distributor is one customer) or on a per delivery point basis (e.g. each delivery point to an entity is "counted" as a customer)? (Note: Where the allocator is based on weightings, the response should reflect whether the weightings are applied per account or per delivery point).

d) If the response to Part (d) is suggests that a combination of account-based and delivery point-based allocators is used, please provide a schedule that sets out each USOA account that is jointly/totally customer-related (per Appendices 7.2 and 7.3 of the Board's September 2006 Cost Allocation Report) and indicate whether the ST class allocator is in each case is based on number of delivery points or number of accounts.

e) The text on page 4 (lines 21-22) states that the lower fixed charge results in a higher volumetric charge:
   i. Which volumetric charge is higher?
   ii. Is this volumetric charge applied to all ST customers?
   iii. If not, why it appropriate to lower the fixed charge and increase the volumetric charge?

f) In cases where the customer owns the lines emanating from the HVDS, is each line emanating from the HVDS considered a separate delivery point? If not, why not?

g) Please provide a schedule that sets out the number of ST customers and the number of ST delivery points (broken down between customer use of a common ST line and customer delivery at the HVDS).

Response

a. The proposed value of $188 is based on the OEB Cost Allocation method c) of determining fixed charges: Minimum System with PLCC Adjustment, adjusted to exclude Low Voltage meter costs. The meter costs excluded from the fixed charge and wholesale meter costs are recovered though the proposed monthly meter charge of $553.

b. i) No, those two situations cover the situations that attract a service charge
ii) N/A because the response to (i) is "no"
iii) N/A because the response to (i) is "no"

c. The customer-related costs are allocated on a delivery point basis.

d. Hydro One assumes that the reference in this question is to part c), not d). The customer-related costs are allocated on a delivery point basis, not on a combination of delivery point and account basis.

e. (i) The Common Line rate is higher.
(ii) The only ST customers to whom this rate would not be applied are those who own their own feeders out of HVDSs.
(iii) It is appropriate to lower the fixed charge so that the service charge and meter charge are consistent with the OEB Cost Allocation model's calculation of Minimum System with PLCC Adjustment (Method c). The Common Line rate applies to virtually all ST customers.

f. Each line emanating from the HVDS would be considered a separate delivery point.

g.

# of ST customers	ST delivery points – common line	ST delivery points – customer-owned feeders from HVDS
341	659	
1	2	1
4		8

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #55 List 1

Interrogatory

Reference: Exhibit G1, Tab 4, Schedule 4, pages 1-4

Question:

a) Please provide a schedule that sets out the proposed 2008 rates for the ST Class, the 2008 billing quantities associated with each "rate" and the resulting revenues. Please reconcile the total revenues with the propose ST Revenue Requirement set out in Exhibit G1, Tab 3, Schedule 1, Table 2.

b) Please provide a schedule that:
- Lists each of the USOA expense/revenue accounts that contributes to the Revenue Requirement and each of asset accounts (including Working Capital) that contribute to Rate Base allocated to the ST Class
- Identifies the allocator(s) used to allocate each account in the preceding bullet to the ST class.
- Identifies both the total dollars and the dollars allocated to the ST class for each of the accounts in the first bullet – broken by allocators when more than one is used.

c) Based on the results from part (b), please describe how the portion of the ST Revenue Requirement to be recovered by each ST Proposed Monthly Charge in Table #1 (including the fixed charges) was determined. In doing so, please indicate how the proposed revenue to cost ratio of 1.15 was incorporated into the derivation of the rates (e.g., are all of the rates based on 115% of costs?).

d) Please explain why:
- The rates for Common/Shared lines; HVDSs and LVDSs are all decreasing but
- The rates for Specific LV Lines and Specific Distribution Lines are increasing.

Response

a. The table below includes the breakdown of the ST Revenues as shown in Exhibit G1, Tab 3, Schedule 1, Table 2.

	2008 monthly Rate or Charge	units	Quantity (annual)	Revenue ($M)
Service Charge	$188		8,040	$ 1.5
Meter Charge	$553		4,296	$ 2.4
Common Line	0.58	$ / kW	37,800,000	$ 22.0
Specific ST Line	729	$ / km	1,514	$ 1.1
Specific Primary Line	565	$ / km	3.7	$ -
HVDS-high	1.42	$ / kW	1,700,000	$ 2.4
HVDS-low	2.66	$ / kW	150,000	$ 0.4
LVDS-low	1.24	$ / kW	1,400,000	$ 1.7
Total				$ 31.5

b. The listing of all asset and expense accounts and their associated dollar balances can be found in the Cost Allocation Model contained in Exhibit G2, Tab 1, Schedule 1, Attachment A O4: Summary by Class & Account pages 50 to 58 inclusive. All the USoA accounts have been represented below with the Total Balances and the allocated amounts to ST. The allocators per account can be found in E4 TB Allocation Details of the Cost Allocation Model on pages 125 to 134 inclusive

USoA Account #	**Accounts**	**O1 Grouping**	Total	ST
1565	Conservation and Demand Management Expenditures and Recoveries	**dp**	$ 6,400,000	$ 125,463
1608	Franchises and Consents	**gp**	$ -	$ -
1805	Land	**dp**	$ -	$ -
1805-1	Land Station >50 kV	**dp**	$ 6,121,920	$ 2,910,894
1805-2	Land Station <50 kV	**dp**	$ 55,097,277	$ 1,500,596
1806	Land Rights	**dp**	$ -	$ -
1806-1	Land Rights Station >50 kV	**dp**	$ 23,947,805	$ 11,386,873
1806-2	Land Rights Station <50 kV	**dp**	$ 215,530,242	$ 5,870,049
1808	Buildings and Fixtures	**dp**	$ -	$ -
1808-1	Buildings and Fixtures > 50 kV	**dp**	$ 2,718,897	$ 1,292,800
1808-2	Buildings and Fixtures < 50 KV	**dp**	$ 2,718,897	$ 74,050
1810	Leasehold Improvements	**dp**	$ -	$ -
1810-1	Leasehold Improvements >50 kV	**dp**	$ -	$ -
1810-2	Leasehold Improvements <50 kV	**dp**	$ -	$ -
1815	Transformer Station Equipment - Normally Primary above 50 kV	**dp**	$ -	$ -
1815-1	HVDS - Rural	**dp**	$ 86,497,684	$ -
1815-2	HVDS - lo LV Specific	**dp**	$ 571,618	$ 571,618

1815-3	HVDS - hi LV Specific	**dp**	$ 1,908,989	$ 1,908,989
1815-4	HVDS - lo LV Shared	**dp**	$ 9,437,091	$ 9,437,091
1815-5	HVDS - hi LV Shared	**dp**	$ 9,437,091	$ 9,437,091
1820	Distribution Station Equipment - Normally Primary below 50 kV	**dp**	$ -	$ -
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)	**dp**	$ -	$ -
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)	**dp**	$ 287,412,402	$ 8,235,782
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)	**dp**	$ 39,824,763	$ 8,363,003
1825	Storage Battery Equipment	**dp**	$ -	$ -
1825-1	Storage Battery Equipment > 50 kV	**dp**	$ -	$ -
1825-2	Storage Battery Equipment <50 kV	**dp**	$ -	$ -
1830	Poles, Towers and Fixtures	**dp**	$ -	$ -
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	**dp**	$ -	$ -
1830-3A	Bulk-LV Fixtures	**dp**	$ 50,225,910	$ 50,225,910
1830-3B	Bulk-Retail Fixtures	**dp**	$ 336,127,241	$ -
1830-4	Poles, Towers and Fixtures - Primary	**dp**	$ -	$ -
1830-4A	Primary-LV Fixtures	**dp**	$ 1,403,814	$ 1,403,814
1830-4B	Primary-Retail Fixtures	**dp**	$ 1,254,243,925	$ -
1830-5	Poles, Towers and Fixtures - Secondary	**dp**	$ 289,764,863	$ -
1835	Overhead Conductors and Devices	**dp**	$ -	$ -
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	**dp**	$ -	$ -
1835-3A	Bulk-LV Conductors	**dp**	$ 33,587,887	$ 33,587,887
1835-3B	Bulk-Retail Conductors	**dp**	$ 224,780,475	$ -
1835-4	Overhead Conductors and Devices - Primary	**dp**	$ -	$ -
1835-4A	Primary-LV Conductors	**dp**	$ 938,781	$ 938,781
1835-4B	Primary-Retail Conductors	**dp**	$ 838,758,394	$ -
1835-5	Overhead Conductors and Devices - Secondary	**dp**	$ 193,776,271	$ -
1840	Underground Conduit	**dp**	$ -	$ -
1840-3	Underground Conduit - Bulk Delivery	**dp**	$ -	$ -
1840-4	Underground Conduit - Primary	**dp**	$ 4,796,878	$ -
1840-5	Underground Conduit - Secondary	**dp**	$ 19,187,512	$ -
1845	Underground Conductors and Devices	**dp**	$ -	$ -
1845-3	Underground Conductors and Devices - Bulk Delivery	**dp**	$ -	$ -
1845-4	Underground Conductors and Devices - Primary	**dp**	$ 135,887,801	$ -
1845-5	Underground Conductors and Devices - Secondary	**dp**	$ 543,551,206	$ -
1850	Line Transformers	**dp**	$ -	$ -
1850-1	TRF-LV	**dp**	$ 3,851,801	$ 3,851,801
1850-2	TRF-Rural	**dp**	$ 1,280,081,943	$ -

1855	Services	**dp**	$ -	$ -
1860	Meters	**dp**	$ -	$ -
1860-1	Mtr-Single	**dp**	$ 13,081,021	$ -
1860-2	Mtr-Poly	**dp**	$ 5,379,048	$ -
1860-3	Mtr-LV	**dp**	$ 6,689,107	$ 6,689,107
1860-4	Mtr-Smart	**dp**	$ 147,740,678	$ 84,437
1875	Street Lights	**dp**	$ -	$ -
1905	Land	**gp**	$ 3,283,798	$ 83,411
1906	Land Rights	**gp**	$ -	$ -
1908	Buildings and Fixtures	**gp**	$ 94,901,052	$ 2,410,569
1910	Leasehold Improvements	**gp**	$ 4,620,582	$ 117,367
1915	Office Furniture and Equipment	**gp**	$ 2,536,853	$ 64,438
1920	Computer Equipment - Hardware	**gp**	$ 55,593,665	$ 1,412,127
1925	Computer Software	**gp**	$ 205,570,861	$ 5,221,678
1930	Transportation Equipment	**gp**	$ 199,220,074	$ 5,060,363
1935	Stores Equipment	**gp**	$ 6,587,180	$ 167,320
1940	Tools, Shop and Garage Equipment	**gp**	$ 2,282,022	$ 57,965
1945	Measurement and Testing Equipment	**gp**	$ 3,066,387	$ 77,889
1950	Power Operated Equipment	**gp**	$ 85,055,133	$ 2,160,474
1955	Communication Equipment	**gp**	$ 28,160,887	$ 715,311
1960	Miscellaneous Equipment	**gp**	$ 2,998,695	$ 76,169
1970	Load Management Controls - Customer Premises	**gp**	$ -	$ -
1975	Load Management Controls - Utility Premises	**gp**	$ -	$ -
1980	System Supervisory Equipment	**gp**	$ 21,869,131	$ 555,495
1985	Sentinel Lgts	**gp**	$ 16,327,748	$ -
1990	Other Tangible Property	**gp**	$ 5,274,886	$ 133,987
1995	Contributions and Grants - Credit	**co**	$ (418,704,641)	$ (6,945,420)
2005	Property Under Capital Leases	**gp**	$ -	$ -
2010	Electric Plant Purchased or Sold	**gp**	$ -	$ -
2105	Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	**accum dep**	$ (2,364,639,589)	$ (61,912,930)
2120	Accumulated Amortization of Electric Utility Plant - Intangibles	**accum dep**	$ -	$ -
3046	Balance Transferred From Income	**NI**	$ (151,400,000)	$ (3,994,232)
4080	Distribution Services Revenue	**CREV**	$ (1,024,275,593)	$ (63,422,672)
4082	Retail Services Revenues	**mi**	$ -	$ -
4084	Service Transaction Requests (STR) Revenues	**mi**	$ -	$ -
4090	Electric Services Incidental to Energy Sales	**mi**	$ -	$ -
4205	Interdepartmental Rents	**mi**	$ -	$ -
4210	Rent from Electric Property	**mi**	$ -	$ -
4215	Other Utility Operating Income	**mi**	$ -	$ -
4220	Other Electric Revenues	**mi**	$ -	$ -
4225	Late Payment Charges	**mi**	$ (14,500,000)	$ (476,654)
4235	Miscellaneous Service Revenues	**mi**	$ (27,800,000)	$ (131,175)

4240	Provision for Rate Refunds	**mi**	$ -	$ -
4245	Government Assistance Directly Credited to Income	**mi**	$ -	$ -
4305	Regulatory Debits	**mi**	$ -	$ -
4310	Regulatory Credits	**mi**	$ -	$ -
4315	Revenues from Electric Plant Leased to Others	**mi**	$ -	$ -
4320	Expenses of Electric Plant Leased to Others	**mi**	$ -	$ -
4325	Revenues from Merchandise, Jobbing, Etc.	**mi**	$ -	$ -
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	**mi**	$ -	$ -
4335	Profits and Losses from Financial Instrument Hedges	**mi**	$ -	$ -
4340	Profits and Losses from Financial Instrument Investments	**mi**	$ -	$ -
4345	Gains from Disposition of Future Use Utility Plant	**mi**	$ -	$ -
4350	Losses from Disposition of Future Use Utility Plant	**mi**	$ -	$ -
4355	Gain on Disposition of Utility and Other Property	**mi**	$ -	$ -
4360	Loss on Disposition of Utility and Other Property	**mi**	$ -	$ -
4365	Gains from Disposition of Allowances for Emission	**mi**	$ -	$ -
4370	Losses from Disposition of Allowances for Emission	**mi**	$ -	$ -
4390	Miscellaneous Non-Operating Income	**mi**	$ -	$ -
4395	Rate-Payer Benefit Including Interest	**mi**	$ -	$ -
4398	Foreign Exchange Gains and Losses, Including Amortization	**mi**	$ -	$ -
4405	Interest and Dividend Income	**mi**	$ -	$ -
4415	Equity in Earnings of Subsidiary Companies	**mi**	$ -	$ -
4705	Power Purchased	**cop**	$ 1,959,300,000	$ 411,443,278
4708	Charges-WMS	**cop**	$ -	$ -
4710	Cost of Power Adjustments	**cop**	$ -	$ -
4712	Charges-One-Time	**cop**	$ -	$ -
4714	Charges-NW	**cop**	$ -	$ -
4715	System Control and Load Dispatching	**cop**	$ -	$ -
4716	Charges-CN	**cop**	$ -	$ -
4730	Rural Rate Assistance Expense	**cop**	$ -	$ -
5005	Operation Supervision and Engineering	**di**	$ 2,234,150	$ 43,329
5010	Load Dispatching	**di**	$ 849,600	$ 16,477
5012	Station Buildings and Fixtures Expense	**di**	$ 396,000	$ 99,539
5014	Transformer Station Equipment - Operation Labour	**di**	$ 590,000	$ 116,820
5015	Transformer Station Equipment - Operation Supplies and Expenses	**di**	$ 290,000	$ 57,420

5016	Distribution Station Equipment - Operation Labour	**di**	$ 6,620,000	$ 189,696
5017	Distribution Station Equipment - Operation Supplies and Expenses	**di**	$ 2,500,000	$ 71,637
5020	Overhead Distribution Lines and Feeders - Operation Labour	**di**	$ 6,030,870	$ 123,732
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	**di**	$ 987,630	$ 20,263
5030	Overhead Subtransmission Feeders - Operation	**di**	$ 564,400	$ 24,997
5035	Overhead Distribution Transformers- Operation	**di**	$ -	$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	**di**	$ -	$ -
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	**di**	$ -	$ -
5050	Underground Subtransmission Feeders - Operation	**di**	$ -	$ -
5055	Underground Distribution Transformers - Operation	**di**	$ -	$ -
5065	Meter Expense	**cu**	$ 8,157,050	$ 482,781
5070	Customer Premises - Operation Labour	**cu**	$ 15,338,600	$ 8,699
5075	Customer Premises - Materials and Expenses	**cu**	$ 2,325,800	$ 1,319
5085	Miscellaneous Distribution Expense	**di**	$ 11,169,190	$ 216,614
5090	Underground Distribution Lines and Feeders - Rental Paid	**di**	$ -	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	**di**	$ 162,160	$ 3,327
5096	Other Rent	**di**	$ -	$ -
5105	Maintenance Supervision and Engineering	**di**	$ 11,257,600	$ 218,329
5110	Maintenance of Buildings and Fixtures - Distribution Stations	**di**	$ -	$ -
5112	Maintenance of Transformer Station Equipment	**di**	$ 1,895,500	$ 375,309
5114	Maintenance of Distribution Station Equipment	**di**	$ 18,339,300	$ 525,511
5120	Maintenance of Poles, Towers and Fixtures	**di**	$ 20,408,580	$ 463,891
5125	Maintenance of Overhead Conductors and Devices	**di**	$ 51,236,400	$ 1,111,219
5130	Maintenance of Overhead Services	**di**	$ -	$ -
5135	Overhead Distribution Lines and Feeders - Right of Way	**di**	$ 121,155,000	$ 2,485,665
5145	Maintenance of Underground Conduit	**di**	$ 265,540	$ -
5150	Maintenance of Underground Conductors and Devices	**di**	$ 1,130,000	$ -
5155	Maintenance of Underground Services	**di**	$ -	$ -
5160	Maintenance of Line Transformers	**di**	$ 3,196,880	$ 9,591
5175	Maintenance of Meters	**cu**	$ 1,846,200	$ 72,331

5305	Supervision	**cu**	$ -	$ -
5310	Meter Reading Expense	**cu**	$ 23,513,850	$ -
5315	Customer Billing	**cu**	$ 35,828,600	$ 169,058
5320	Collecting	**cu**	$ 8,626,330	$ 40,703
5325	Collecting- Cash Over and Short	**cu**	$ -	$ -
5330	Collection Charges	**cu**	$ 869,820	$ 4,104
5335	Bad Debt Expense	**cu**	$ 17,396,400	$ 473,480
5340	Miscellaneous Customer Accounts Expenses	**cu**	$ 4,763,820	$ 22,478
5405	Supervision	**ad**	$ -	$ -
5410	Community Relations - Sundry	**ad**	$ 673,080	$ 13,195
5415	Energy Conservation	**ad**	$ 1,000,000	$ 19,604
5420	Community Safety Program	**ad**	$ 864,318	$ 21,954
5425	Miscellaneous Customer Service and Informational Expenses	**ad**	$ 10,200	$ 200
5505	Supervision	**ad**	$ -	$ -
5510	Demonstrating and Selling Expense	**ad**	$ -	$ -
5515	Advertising Expense	**ad**	$ -	$ -
5520	Miscellaneous Sales Expense	**ad**	$ -	$ -
5605	Executive Salaries and Expenses	**ad**	$ 5,793,895	$ 113,582
5610	Management Salaries and Expenses	**ad**	$ 21,599,559	$ 423,430
5615	General Administrative Salaries and Expenses	**ad**	$ 31,794,404	$ 623,287
5620	Office Supplies and Expenses	**ad**	$ -	$ -
5625	Administrative Expense Transferred Credit	**ad**	$ (49,300,954)	$ (966,479)
5630	Outside Services Employed	**ad**	$ 6,548,043	$ 128,366
5635	Property Insurance	**ad**	$ 2,715,447	$ 68,975
5640	Injuries and Damages	**ad**	$ 1,694,082	$ 33,210
5645	Employee Pensions and Benefits	**ad**	$ 23,592,000	$ 462,490
5650	Franchise Requirements	**ad**	$ -	$ -
5655	Regulatory Expenses	**ad**	$ 4,993,529	$ 97,891
5660	General Advertising Expenses	**ad**	$ -	$ -
5665	Miscellaneous General Expenses	**ad**	$ (413,370)	$ (8,104)
5670	Rent	**ad**	$ 7,740,487	$ 151,742
5675	Maintenance of General Plant	**ad**	$ 58,312,009	$ 1,143,129
5680	Electrical Safety Authority Fees	**ad**	$ -	$ -
5685	Independent Market Operator Fees and Penalties	**cop**	$ -	$ -
5705	Amortization Expense - Property, Plant, and Equipment	**dep**	$ 207,380,346	$ 5,125,788
5710	Amortization of Limited Term Electric Plant	**dep**	$ -	$ -
5715	Amortization of Intangibles and Other Electric Plant	**dep**	$ -	$ -
5720	Amortization of Electric Plant Acquisition Adjustments	**dep**	$ -	$ -
5730	Amortization of Unrecovered Plant and Regulatory Study Costs	**dep**	$ -	$ -

5735	Amortization of Deferred Development Costs	**dep**	$ -	$ -
5740	Amortization of Deferred Charges	**dep**	$ -	$ -
6005	Interest on Long Term Debt	**INT**	$ 148,500,000	$ 3,917,724
6105	Taxes Other Than Income Taxes	**ad**	$ 4,464,000	$ 117,769
6110	Income Taxes	**Input**	$ 50,100,000	$ 1,321,737
6205	Donations	**ad**	$ -	$ -
6210	Life Insurance	**ad**	$ -	$ -
6215	Penalties	**ad**	$ -	$ -
6225	Other Deductions	**ad**	$ -	$ -

c. The ST Revenue Requirement of $27.4 million as determined by the OEB Cost Allocation Model represents the total cost to be recovered through ST rates, if the revenue to cost ratio would be set equal to one. The $27.4 million is comprised of the $27.2 million of ST account values in part b) above and $0.2 Million miscellaneous revenue, (Exhibit G2, Tab 1, Schedule 1, Attachment A, page 36).

HVDS and LVDS rates were determined as described in section 1 below. Specific Line charges are described in section 2 below. Fixed monthly charge and Meter charge are described in section 3 below. The Common Line charge recovers the remainder of the revenues to be collected from all ST customers.

1) Determining the HVDS-high and HVDS-low portions of the Revenue Requirement:

Account values for HVDS were split between LDCs supplied below 13.8 kV (HVDS-lows) and the rest of ST (HVDS-highs). The split was applied to the ST allocation for accounts:

5014 Transformer Station Equipment - Operation Labour
5015 Transformer Station Equipment - Operation Supplies and Expenses
5112 Maintenance of Transformer Station Equipment

These accounts were allocated completely to HVDSs, and were split between HVDS-high and HVDS-low as described above.

Only portions of the ST allocation for the accounts:

5005 Operation Supervision and Engineering
5012 Station Buildings and Fixtures Expense
5105 Maintenance Supervision and Engineering
5405 to 5680 25 General Admin. Acc'ts
3046 Net Inc (Balance Transferred From Income)
5705 Amortization Expense - Property, Plant, and Equipment
6005 Interest on Long Term Debt
6105 Taxes Other Than Income Taxes
6110 Income Taxes

were allocated to HVDSs. First, the account values were split as described above. Then:

The portion of ST excluding LDCs supplied below 13.8 kV for HVDS-highs was the value times A over B:

A -- The gross asset value of the particular HVDS-highs which supply ST-excluding LDCs below 13.8 kV was divided between ST and Retail in proportion to the ST kWh and Retail kWh. The portion for ST was the numerator.

B – The gross asset value allocated to ST (excluding LDCs below 13.8 kV) in the OEB model was the denominator.

Similarly, the portion of LDCs below 13.8 kV for HVDS-lows was the LDC below 13.8 kV value times C over D:

C -- The gross asset value of the particular HVDS-lows which supply LDCs below 13.8 kV was divided between LDCs below 13.8 kV and Retail in proportion to the LDCs below 13.8 kV kWh and Retail kWh. The portion for LDCs below 13.8 kV was the numerator.

D – The gross asset value allocated to LDCs below 13.8 kV in the OEB model was the denominator.

<u>Determining the LVDS-low portion of the Revenue Requirement</u>:

The ST allocation for accounts

5016 Distribution Station Equipment - Operation Labour
5017 Distribution Station Equipment - Operation Supplies and Expenses
5110 Maintenance of Buildings and Fixtures - Distribution Stations
5114 Maintenance of Distribution Station Equipment

were allocated completely to LVDS-lows.

Only portions of the ST allocation for the accounts

5005 Operation Supervision and Engineering
5105 Maintenance Supervision and Engineering
5405 to 5680 25 General Admin. Acc'ts
3046 Net Inc (Balance Transferred From Income)
5705 Amortization Expense - Property, Plant, and Equipment
6005 Interest on Long Term Debt
6105 Taxes Other Than Income Taxes
6110 Income Taxes

were allocated to LVDS-lows.

The portion for LVDS-lows was the LDCs below 13.8 kV value times E over F:

E -- The gross asset value of the particular LVDS-lows which supply LDCs below 13.8 kV was divided between LDCs below 13.8 kV and Retail customer classes in proportion to the LDCs below 13.8 kV kWh and Retail kWh. The portion for LDCs below 13.8 kV was the numerator.

F – The gross asset value allocated to ST in the OEB model was the denominator.

The HVDS-high rate was set such that a customer would pay the same whether they paid via the RTSR Transformation Connection rate or via the HVDS-high rate. The rate multiplied by the kW quantity produced the revenue. Since the HVDS-high rate was tied to the RTSR Transformation Connection rate, the revenue recovered by the rate did not match the Revenue Requirement allocation to HVDS-highs. The difference between the Revenue Requirement and the revenue recovered, was effectively transferred to the Common Line Revenue Requirement, to be recovered by the Common Line rate.

The HVDS-low rate is the sum of the HVDS-high rate and the LVDS-low rate. The HVDS-low rate and LVDS-low rate were set such that together they recovered the Revenue Requirements for HVDS-low and LVDS-low. The LVDS-low rate was set such that the HVDS-high "part" of the HVDS-low rate equaled the HVDS-high rate.

2 To calculate the Specific Line rates, the cost of distribution lines from the OEB Cost Allocation model was divided by the unit-cost-weighted lengths of ST line and Primary line. The specific Line rates multiplied by the km quantities produced the revenue recovered.

3 The service charge was set to $188, the OEB Cost Allocation model's calculation of Minimum System with PLCC Adjustment (method c) once LV metering costs had been removed. The LV and Wholesale metering costs were recovered via the Meter Charge.

The Common Line rate was set to recover the ST costs from the OEB Cost Allocation model less amounts recovered by the HVDS rates, less amounts recovered by the Specific Line rates, plus the amount not collected for the HVDS-highs via the HVDS-high rate (due to tying it to the RTSR Transformation Connection rate as described above), less the revenues collected from the service charge and meter charge.

All the above was done at a Revenue-Cost Ratio of 1. To achieve the Revenue-Cost Ratio of 1.15, the volumetric rates except for HVDS (i.e. LVDS-low, Common Line, Specific Lines), were increased in the same proportion in order to achieve the 1.15 Revenue-Cost Ratio. The proposed fixed charges were left at revenue to cost ratio equal to one.

d. Existing rates are the result of adjustments to the initial unbundled LV rates done proportionally to the change in revenue requirement. The initial unbundled rates were not based on the OEB cost Allocation Model. The proposed rates follow the OEB

Cost Allocation model. Therefore one should not expect that the direction of change from existing rates to proposed rates to be all in the same direction.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #56 List 1

Interrogatory

Reference: Exhibit G1, Tab 4, Schedule 4, page 2, lines 1-9

Question:

a) Please provide a schedule that indicates:
   i. The number of ST customers with one delivery point vs. multiple delivery points
   ii. The number of ST customers with multiple delivery points where all of the relevant delivery points will be aggregated for purposes of the ST Line charges vs. those where ST Line charges will not be based on aggregate demand over all the relevant delivery points.
   iii. The number of ST customers with multiple delivery points where the all of the relevant delivery points will be aggregated for purposes of the HVDS charges vs. those customers where HVDS charges will not be based on aggregate demand over all the relevant delivery points.

b) Please clarify whether the "after October 1998" qualification applies to both non-renewable and renewable generation or just the latter.

Response

a.

i.

Number of ST customers with one delivery point	273
Number of ST customers with multiple delivery points	73

ii.

Number of ST customers with multiple delivery points where all of the delivery points will be aggregated for Common Line charge (i.e. all from one station)	30
Number of ST customers with multiple delivery points where not all of the delivery points will be aggregated for Common Line charge (i.e. from different stations)	43

iii.

Number of ST customers with multiple delivery points where all of the delivery points will be aggregated for an HVDS charge (i.e. all from one station)	7
Number of ST customers with multiple delivery points where not all of the delivery points will be aggregated for an HVDS charge (i.e. from different stations)	1

b. The "after October 1998" qualification applies to both non-renewable and renewable generation.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #57 List 1

Interrogatory

Reference: Exhibit G1, Tab 4, Schedule 5, page 2

Question:

a) With reference to Sheet O3.5 (Exhibit G2-1-1, Attachment A), does the 97,005 customers used to determine the Metering Unit Cost represent: a) the total customers in the GSe class or b) the number of metered customers in the GSe class? If the former, please explain why.

b) With respect to Input Sheet I6 of the Cost Allocation Study (Exhibit G2-1-1, Attachment A):
- Does the Weighted Meter Capital Allocator for GSe reflect the fact that some GSe customers are not metered (i.e., those customers effectively get a "zero" weighting)? If not, why not?
- Does the Weighted Meter Reading Allocator for GSe reflect the fact that some GSe customers are not metered (i.e., those customers effectively get a "zero" weighting)? If not, why not?

c) Please reconcile the number of unmetered connections reported in the Application for the GSe class (4,917) with the value used in the Cost Allocation Study (zero – per Input Sheet I6).

Response

a. The USL Metering Credit of the Cost Allocation Model Sheet 3.5 is based on the customer count of 97,005. The total number is the default level per the OEB' s Cost Allocation Model.

b. The derived Meter Capital for GSe in I7.1 is based on the number of actual metering and thus is exclusive of the Unmetered accounts. Further, the derived Meter Reading for GSe in I7.2 also is exclusive of the unmetered accounts.

c. The unmetered connection of Input 6 Customer is used for the Street and Sentinel Light rate classes which have many units aggregated onto a single account. Since the unmetered accounts are being mapped into the GSe class, the appropriate allocator is the total rate class customer count. If the unmetered connections of Input 6 is populated with 4,917, the GSe allocation is being double counted since the 4,917 accounts are already included in the total GSe count of 97,005.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #58 List 1

Interrogatory

Reference: Exhibit G1, Tab 4, Schedule 6

Question:

a) Please provide a schedule that sets out the derivation of the 14 cents/kWh discount for energy billed customer with their own transformers. Please indicate the sources for any data used in the derivation.

b) What was the value calculated by the Cost Allocation Model for the Transformer Ownership Allowance? Please provide the reference as to where in the Model (Exhibit G2-1-1, Attachment A) filed by Hydro One this value is found.

c) Why is Hydro One proposing to continue with the $0.60/kW as opposed to using the value produced by the Cost Allocation Model?

Response

a. The 0.14 cent/kWh Customer Supplied Transformation Allowance [CSTA] was derived by summing the billing kWh and kWs for customers who received the CSTA in 2006. The demand based CSTA credit was divided by the billed kWh of the same CSTA customers.

CSTA based on $0.60/kW	$3,859,972
CSTA customer kWh	2,783,515,813
CSTA cent/kWh rate	0.14 cent/kWh

b. The Transformer Ownership Allowance is derived in O3.1 Line Tran Unit Cost of the Cost Allocation Model. This tab was not provided as part of Exhibit G2, Tab 1, Schedule 1, Attachment A. Hydro One Distribution and other Distributors have concerns with this part of the Cost Allocation Model.

c. Refer to answer to Part b.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #59 List 1

Interrogatory

Reference: Exhibit G1, Tab 5, pages 2-4

Question:

a) The first Allocation Principle (page 2, lines 10-12) states that "if costs were incurred for the benefit of all customers irrespective of their energy use, number of customers would be the recommended allocator". Please explain why, if number of customers is not the "cost driver", it is a better allocator in such circumstances than for example using share of total distribution costs allocated to each customer class as the "allocator".

b) The second Allocation Principle (page 2, lines 13-16) states that if costs were included in the Revenue Requirement as OM&A then the OM&A allocated to each customer class would be the appropriate allocator. Please explain how this approach is consistent with the principle of cost causality rather than looking at the Cost Allocation treatment of the of the associated OM&A expense itself.

c) Please confirm what USOA Account OEB costs are recorded (e.g. General and Administration). Please explain why the recovery of the Regulatory Assets pertaining to OEB Costs using the same allocation as the Cost Allocation Model applied to OEB costs expensed in 2008 would not be appropriate.

Response

a. The principles outline in Exhibit G1, Tab 5, Schedule 1, page 2, are the same principles used by Hydro One and approve by the OEB when setting Regulatory Rate Riders # 1 and # 2. Total Distribution costs could be an alternative allocator instead of number of customer

b. The recommended OM&A allocator is one way of allocating costs. A more detailed approach would be to use the allocator by customer class for each individual OM&A expense, to the extent that there is an allocator for the expense. Many OM&A accounts are allocated based on the allocation of all other OM&A or Rate Base accounts.

c. OEB costs are recorded in USOA 5665. General Administration is allocated based on all other OM&A costs in the cost allocation study, therefore, OM&A costs allocated by customer class is the recommended allocator. The two accounts included in Rider # 3, OEB costs and Tax change are allocated in the cost allocation study to customer

classes based on all other OM&A accounts and Net Fixed Assets respectively. There are no separate individual allocators for these accounts.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #60 List 1

Interrogatory

Reference: Exhibit G1, Tab 6, Schedule 1, pages 2-5

Question:

a) No reference is made by Hydro One Networks to the Wholesale Meter Pool and related charges. Does Hydro One Networks' Distribution business pay any Wholesale Meter charges? If not, why not? If yes, please undertake the following:
   - Provide the forecasts costs for 2008 and a schedule setting out the calculation on the cost.
   - Explain how the costs will be allocated to customer classes and, then, recovered from the customers in each class.

b) Please provide a schedule setting out the values of billing parameters by class used to establish the rates in Table 2. Please reconcile any differences between these values and those set out in G1, Tab 5, Schedule 3, Table 1.

Response

a. All the Hydro One Distribution legacy wholesale revenue meters have exited from the Wholesale Meter Pool, therefore Hydro One Distribution will not pay Wholesale Meter Charges in 2008.

b. Attachment A contains the re-stated RTSR balances, the class charge determinants and the resultant RTSR rates.

The difference in billing determinants from those used in Exhibit G1, Tab 5, Schedule 1 for Regulatory Asset Rate Rider 3:

- The Rider 3 rate class allocators are based on Retail Level statistics while the RTSR allocators use the same Retail statistics per Rate Class but are uplifted by the class TLF to move the class to the Wholesale point of supply which is where the RSTR charges are being levied by the IESO.
- For the ST class, Rider 3 is based on total bill demand for the class. However, for RTSR, the ST demand for Networks is based on the 7 AM to 7 PM narrow peak period IESO business days. Further, the Connection demand is limited to the peak demand of customers who are charged these charges.

	Wholesale Level Charges		**Wholesale Level Stats**		**Rates exclusive of TLFs**			
	Network	Connection	kWh	kWs	Network Rate		Connection Rate	
					c/kwh	$/kW	c/kwh	$/kW
UR	$ 7,570,443	$ 7,246,842	1,610,732,413		0.47		0.45	
R1	$ 22,697,678	$ 21,922,317	4,782,076,285		0.47		0.46	
R2	$ 28,517,822	$ 26,495,789	6,141,936,529		0.46		0.43	
Seasonal	$ 3,374,629	$ 3,315,300	771,742,703		0.44		0.43	
Uge	$ 1,674,964	$ 1,519,043	463,185,604		0.36		0.33	
Ugd	$ 3,289,432	$ 2,979,208		2,337,698		1.41		1.27
GSe	$ 8,807,534	$ 8,059,625	2,510,853,555		0.35		0.32	
GSd	$ 12,932,797	$ 11,639,498		11,691,631		1.11		1.00
Lights	$ 449,148	$ 397,104	156,172,049		0.29		0.25	
Dgen	$ 13,298	$ 12,040		52,409		0.25		0.23
Retail	$ 89,327,746	$ 83,586,766						

ST	Allocated $	kWs	$/kW
Network	$ 76,899,232	38,272,898	2.01
Line	$ 16,207,183	32,136,412	0.50
Transformation	$ 51,593,835	37,417,280	1.38

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #61 List 1

Interrogatory

Reference: Exhibit G1, Tab 7, Schedule 1, pages5-7

Question:

a) Please confirm that in the 2006 EDR process there was no change in the classification of customers, the allocation of costs to customer classes nor any change in the fixed/variable split by customer class.

b) Please confirm that in the current Application, Legacy customer in the residential classes will see a change in the fixed/variable split used for distribution rates. If not, please explain.

c) Please confirm that, with a shift in the fixed/variable split, the bill impact for the Basic Distribution Bill will vary by usage.

d) If parts (a) through (c) are confirmed, why is it appropriate to only use the average customer profile by customer class when assessing bill impacts.

e) Table 4 (page 7) shows that there are existing farm customers who are currently receiving RRA that will be transferred to the new GSd class. Will these customers continue to receive RRA? If not, why not?

f) For each of the new Residential Classes (UR, R1 and R2) please provide:
- A schedule that sets out the number of customers broken down into a frequency distribution based on monthly use at 200 kWh/month intervals.
- A schedule that sets out the number of customer broken into a frequency distribution based on Total Bill Impact (including Distribution, Riders and RTSR) at 0.5% intervals using the Target Distribution Rates.
- A schedule that sets out the number of customer broken into a frequency distribution based on Basic Distribution Bill Only Impact at 0.5% intervals using the Target Distribution Rates.

Response

a. Yes, in the 2006 EDR process there was no change in the classification of customers, the allocation of costs to customer classes, nor the fixed-variable split per customer class.

b. Yes, the Acquired customers are expected to see a new fixed-variable split in their distribution charges as the result of the Cost Allocation Model and Rate Design process.

c. Yes, with a change in the fixed-variable split, the bill impact will vary by usage.

d. Impacts are done on the average customer per Rate Class consistent with the 2006 EDR Handbook Chapter 13.

e. The proposal is that only customers in the R2 rate class will continue to receive RRRP. Those farms currently with RRRP who are moving to GSd will no longer receive the RRRP credit.

f. New residential rate class details:

   a. The detailed decomposition of the new proposed rate classes is not available. However, the details of the existing rate classes can be provided using 2006 data at 250 kWh intervals consistent with the impact ranges requested by the OEB. Attachment A contains the customer composition for the existing UR, R1, R2 and each Acquired Distributor residential class. Caledon re-mapped classes of OH-01, OH-06 and OH-07 are excluded for the analysis. No data exists for 2006 for Terrace Bay customers.

   b. Total bill impacts at the Target Rates at the various consumption levels of Exhibit G2, Tab 5, Schedule 6, is provided which combined with part a) above can be used to determine customer impacts per consumption band. Refer to Attachment B.

   c. Distribution bill impacts at the Target Rates at the various consumption levels of Exhibit G2, Tab 5, Schedule 3, is provided which combined with part a) above can be used to determine customer impacts per consumption band. Refer to Attachment C.

Rate Class	0-250	250-500	500-750	750-1000	1000-1500	1500-2000	2000+	2006 Total
UR	5,115	17,504	23,167	16,609	14,221	3,989	1,914	82,519
R1	15,264	45,202	67,513	59,451	67,454	28,586	20,791	304,261
R2	11,135	25,537	47,316	52,897	72,240	34,366	28,911	272,402
Ailsa Craig	17	66	103	74	64	20	4	348
Arkona	6	51	70	45	34	8	3	217
Arnprior	255	793	955	584	383	107	57	3,134
Arran-Elderslie	84	225	351	315	403	199	104	1,681
Artemesia	39	76	99	77	74	26	21	412
Bancroft	53	160	257	182	196	93	61	1,002
Bath	40	159	239	151	111	33	4	737
Blandford-Blenheim	44	143	231	192	175	36	17	838
Blyth	16	89	106	49	94	20	8	382
Bobcaygeon	70	182	229	219	468	328	145	1,641
Brighton	145	486	661	464	350	151	63	2,320
Brockville	655	2,206	2,242	1,413	1,219	370	232	8,337
Caledon	51	332	572	497	486	119	58	2,115
Campbellford	93	274	356	269	278	109	48	1,427
Carleton Place	251	896	1,123	720	496	152	73	3,711
Chalk River	11	61	88	93	82	31	10	376
Champlain Twp	131	275	347	298	394	159	111	1,715
Chatsworth	12	49	50	33	27	8	-	179
Cobden	45	131	141	76	55	15	6	469
Deep River	94	372	469	289	291	141	85	1,741
Delaware Village	6	37	107	92	113	32	11	398
Deseronto	31	105	173	144	134	51	26	664
Dryden	235	685	816	500	283	74	40	2,633
Dundalk	33	112	179	150	138	55	20	687
Durham	133	319	317	185	100	37	19	1,110
Eganville	33	85	147	122	105	34	19	545
Elmvale	28	197	212	127	124	33	14	735
Erin	34	170	227	241	166	48	18	904
Exeter	152	472	533	388	309	90	42	1,986
Fenelon Falls	92	158	148	142	230	117	83	970
Forest	71	261	318	245	202	54	16	1,167
Glencoe	73	240	228	160	114	25	10	850
Grand Bend	283	279	194	127	104	32	19	1,038
Granton	8	28	46	30	18	2	3	135
Hastings	46	82	103	101	90	60	21	503
Havelock	25	68	156	105	114	28	14	510
Kemptville	82	331	376	267	195	80	28	1,359
Kirkfield	5	13	18	19	33	13	6	107
Lanark	21	46	79	77	78	28	8	337
Larder Lake	52	54	76	55	80	45	21	383
Latchford	27	25	31	33	50	17	5	188
Lindsay	406	1,576	1,822	1,107	1,052	392	159	6,514
Listowel	235	632	671	413	335	93	40	2,419
Lucan	51	131	205	165	128	26	9	715
Madoc Village	26	126	139	146	134	57	19	647
Malahide	8	32	57	58	58	18	12	243
Mapleton	45	183	210	148	107	23	6	722
Markdale	55	115	173	120	106	46	19	634
Marmora	33	83	138	114	112	69	30	579
Meaford	221	585	516	334	274	68	29	2,027
Millbrook	30	114	164	125	91	27	9	560
Napanee	182	520	586	360	288	81	19	2,036
Nipigon	136	251	201	87	38	8	7	728
North Dorchester	39	115	176	174	158	41	10	713
North Dundas	68	251	409	296	306	113	67	1,510
North Glengarry	98	320	451	403	399	152	78	1,901
North Stormont	19	80	83	56	71	19	7	335

Omemee	25	66	104	111	118	58	26	508
Owen Sound	758	2,121	2,179	1,316	1,058	274	127	7,833
Perth	325	788	771	468	336	99	58	2,845
Perth East	17	79	104	104	142	63	39	548
Prince Edward County	234	740	795	538	531	174	80	3,092
Quinte West	344	1,327	1,855	1,379	1,214	385	158	6,662
Rainy River	43	88	96	63	57	19	12	378
Ramara	8	13	20	17	22	13	6	99
Red Rock	57	128	112	35	17	2	3	354
Rockland	117	530	767	677	854	380	211	3,536
Russell	20	96	170	199	225	84	53	847
Schreiber	64	55	115	113	119	64	63	593
Severn	32	112	157	119	101	39	17	577
Shelburne	102	361	503	381	260	65	31	1,703
Smiths Falls	348	1,017	1,047	651	486	115	71	3,735
South Glengarry	29	66	94	74	106	49	22	440
South River Town	40	121	132	79	60	32	9	473
Stirling Village	33	143	230	175	163	43	21	808
Stouffville	95	564	847	779	712	206	91	3,294
Sutton	82	188	256	199	234	117	56	1,132
Thedford	35	79	80	53	37	7	4	295
Thessalon	54	129	134	102	80	31	20	550
Thorndale	3	26	41	32	29	4	4	139
Thorold	542	1,549	2,101	1,489	1,088	229	104	7,102
Tweed	48	125	157	128	136	38	29	661
Virginiatown	36	51	57	64	59	14	16	297
Wardsville	8	33	41	29	18	13	1	143
Warkworth	13	42	58	55	58	20	12	258
West Elgin	101	245	298	171	136	31	7	989
Wiarton	68	130	243	153	193	83	23	893
Woodville	9	36	56	64	78	38	39	320
Wyoming	49	194	250	176	130	22	8	829

New Rate Class: UR

Total Bill Impacts of Target Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Rates Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	UR	100	**14.32**	**1.83**	**0.20**	**0.05**	**2.08**	16.4	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	24.3	24.3	0.1	0.3%
		250	14.32	1.83	0.20	0.05	2.08	19.5	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.7	1.078	5.9	250	-	13.5	39.2	39.4	0.2	0.5%
		500	14.32	1.83	0.20	0.05	2.08	24.7	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.7	1.078	11.8	500	-	27.0	64.0	64.4	0.4	0.6%
		750	14.32	1.83	0.20	0.05	2.08	29.9	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.7	1.078	17.7	600	150	42.3	90.9	91.3	0.5	0.5%
		1,000	14.32	1.83	0.20	0.05	2.08	35.1	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.7	1.078	23.6	600	400	58.2	118.2	118.8	0.6	0.5%
		1,500	14.32	1.83	0.20	0.05	2.08	45.5	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.7	1.078	35.4	600	900	90.0	172.8	173.8	1.0	0.6%
		2,000	14.32	1.83	0.20	0.05	2.08	55.9	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.7	1.078	47.2	600	1,400	121.8	227.4	228.7	1.3	0.6%
UR	R1	100	**19.04**	**2.38**	**0.15**	**0.07**	**2.60**	21.6	**14.32**	**2.29**	**-**	**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	29.5	24.3	(5.2)	-17.5%
		250	19.04	2.38	0.15	0.07	2.60	25.5	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	45.2	39.4	(5.8)	-12.9%
		500	19.04	2.38	0.15	0.07	2.60	32.0	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	71.4	64.4	(6.9)	-9.7%
		750	19.04	2.38	0.15	0.07	2.60	38.5	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	99.5	91.3	(8.1)	-8.2%
		1,000	19.04	2.38	0.15	0.07	2.60	45.0	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	128.1	118.8	(9.3)	-7.2%
		1,500	19.04	2.38	0.15	0.07	2.60	58.0	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	185.3	173.8	(11.6)	-6.2%
		2,000	19.04	2.38	0.15	0.07	2.60	71.0	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	242.6	228.7	(13.8)	-5.7%
UR	R2	100	**29.22**	**1.94**	**0.12**	**0.13**	**2.19**	31.4	**14.32**	**2.29**	**-**	**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	39.3	24.3	(14.9)	-38.0%
		250	29.22	1.94	0.12	0.13	2.19	34.7	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	54.4	39.4	(15.0)	-27.6%
		500	29.22	1.94	0.12	0.13	2.19	40.2	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	79.5	64.4	(15.1)	-19.0%
		750	29.22	1.94	0.12	0.13	2.19	45.6	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	106.6	91.3	(15.2)	-14.3%
		1,000	29.22	1.94	0.12	0.13	2.19	51.1	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	134.2	118.8	(15.4)	-11.5%
		1,500	29.22	1.94	0.12	0.13	2.19	62.1	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	189.4	173.8	(15.6)	-8.2%
		2,000	29.22	1.94	0.12	0.13	2.19	73.0	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	244.5	228.7	(15.8)	-6.5%
UR	F1	100	**28.61**	**2.24**	**0.08**	**0.10**	**2.42**	31.0	**14.32**	**2.29**	**-**	**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	38.8	24.3	(14.5)	-37.3%
		250	28.61	2.24	0.08	0.10	2.42	34.7	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	54.2	39.4	(14.8)	-27.3%
		500	28.61	2.24	0.08	0.10	2.42	40.7	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	79.8	64.4	(15.3)	-19.2%
		750	28.61	2.24	0.08	0.10	2.42	46.8	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	107.3	91.3	(16.0)	-14.9%
		1,000	28.61	2.24	0.08	0.10	2.42	52.8	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	135.3	118.8	(16.5)	-12.2%
		1,500	28.61	2.24	0.08	0.10	2.42	64.9	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	191.4	173.8	(17.6)	-9.2%
		2,000	28.61	2.24	0.08	0.10	2.42	77.0	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	247.4	228.7	(18.7)	-7.6%

New Rate Class: UR

Total Bill Impacts of Target Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Rates Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	Arnprior	100	**11.54**	**1.47**	**0.49**	**0.18**	**2.14**	13.7	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	21.4	24.3	3.0	13.8%
		250	11.54	1.47	0.49	0.18	2.14	16.9	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	36.1	39.4	3.2	8.9%
		500	11.54	1.47	0.49	0.18	2.14	22.2	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	60.7	64.4	3.7	6.0%
		750	11.54	1.47	0.49	0.18	2.14	27.6	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.1	91.3	4.3	4.9%
		1,000	11.54	1.47	0.49	0.18	2.14	32.9	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.0	118.8	4.8	4.2%
		1,500	11.54	1.47	0.49	0.18	2.14	43.6	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.0	173.8	5.8	3.4%
		2,000	11.54	1.47	0.49	0.18	2.14	54.3	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	222.0	228.7	6.8	3.0%
UR	Brockville	100	**12.33**	**0.93**	**0.48**	**0.16**	**1.57**	13.9	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	21.6	24.3	2.7	12.7%
		250	12.33	0.93	0.48	0.16	1.57	16.3	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	35.5	39.4	3.9	10.9%
		500	12.33	0.93	0.48	0.16	1.57	20.2	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	58.7	64.4	5.7	9.8%
		750	12.33	0.93	0.48	0.16	1.57	24.1	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	83.6	91.3	7.8	9.3%
		1,000	12.33	0.93	0.48	0.16	1.57	28.0	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	109.1	118.8	9.7	8.9%
		1,500	12.33	0.93	0.48	0.16	1.57	35.9	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	160.2	173.8	13.5	8.4%
		2,000	12.33	0.93	0.48	0.16	1.57	43.7	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	211.3	228.7	17.4	8.2%
UR	Caledon OH 01	100	**18.52**	**0.57**	**0.42**	**0.16**	**1.15**	19.7	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	27.4	24.3	(3.0)	-11.1%
		250	18.52	0.57	0.42	0.16	1.15	21.4	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	40.6	39.4	(1.3)	-3.2%
		500	18.52	0.57	0.42	0.16	1.15	24.3	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.8	64.4	1.6	2.6%
		750	18.52	0.57	0.42	0.16	1.15	27.1	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	86.6	91.3	4.7	5.4%
		1,000	18.52	0.57	0.42	0.16	1.15	30.0	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	111.1	118.8	7.7	6.9%
		1,500	18.52	0.57	0.42	0.16	1.15	35.8	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	160.1	173.8	13.6	8.5%
		2,000	18.52	0.57	0.42	0.16	1.15	41.5	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	209.1	228.7	19.6	9.4%
UR	Carleton Place	100	**14.17**	**1.79**	**0.38**	**0.15**	**2.32**	16.5	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	24.2	24.3	0.1	0.6%
		250	14.17	1.79	0.38	0.15	2.32	20.0	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	39.4	0.1	0.4%
		500	14.17	1.79	0.38	0.15	2.32	25.8	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.3	64.4	0.1	0.2%
		750	14.17	1.79	0.38	0.15	2.32	31.6	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	91.1	91.3	0.3	0.3%
		1,000	14.17	1.79	0.38	0.15	2.32	37.4	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.5	118.8	0.3	0.3%
		1,500	14.17	1.79	0.38	0.15	2.32	49.0	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	173.3	173.8	0.4	0.3%
		2,000	14.17	1.79	0.38	0.15	2.32	60.6	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	228.2	228.7	0.5	0.2%

New Rate Class: UR

Total Bill Impacts of Target Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Rates Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	Dryden	100	**14.28**	**1.65**	**0.43**	**0.18**	**2.26**	16.5	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	24.2	24.3	0.1	0.4%
		250	14.28	1.65	0.43	0.18	2.26	19.9	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	39.4	0.2	0.5%
		500	14.28	1.65	0.43	0.18	2.26	25.6	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.1	64.4	0.3	0.5%
		750	14.28	1.65	0.43	0.18	2.26	31.2	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	90.7	91.3	0.6	0.7%
		1,000	14.28	1.65	0.43	0.18	2.26	36.9	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.0	118.8	0.8	0.7%
		1,500	14.28	1.65	0.43	0.18	2.26	48.2	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	172.5	173.8	1.2	0.7%
		2,000	14.28	1.65	0.43	0.18	2.26	59.5	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	227.1	228.7	1.6	0.7%
UR	GBE	100	**9.68**	**0.95**	**0.46**	**0.13**	**1.54**	11.2	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	18.9	24.3	5.4	28.6%
		250	9.68	0.95	0.46	0.13	1.54	13.5	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	32.8	39.4	6.6	20.1%
		500	9.68	0.95	0.46	0.13	1.54	17.4	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	55.9	64.4	8.5	15.3%
		750	9.68	0.95	0.46	0.13	1.54	21.2	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	80.7	91.3	10.6	13.2%
		1,000	9.68	0.95	0.46	0.13	1.54	25.1	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.2	118.8	12.6	11.9%
		1,500	9.68	0.95	0.46	0.13	1.54	32.8	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.1	173.8	16.6	10.6%
		2,000	9.68	0.95	0.46	0.13	1.54	40.5	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.1	228.7	20.6	9.9%
UR	Lindsay	100	**15.81**	**1.01**	**0.41**	**0.14**	**1.56**	17.4	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	25.1	24.3	(0.7)	-2.9%
		250	15.81	1.01	0.41	0.14	1.56	19.7	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.0	39.4	0.4	1.0%
		500	15.81	1.01	0.41	0.14	1.56	23.6	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.1	64.4	2.3	3.7%
		750	15.81	1.01	0.41	0.14	1.56	27.5	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.0	91.3	4.4	5.0%
		1,000	15.81	1.01	0.41	0.14	1.56	31.4	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	112.5	118.8	6.3	5.6%
		1,500	15.81	1.01	0.41	0.14	1.56	39.2	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	163.6	173.8	10.2	6.2%
		2,000	15.81	1.01	0.41	0.14	1.56	47.0	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	214.6	228.7	14.1	6.6%
UR	Perth	100	**14.47**	**1.22**	**0.50**	**0.18**	**1.90**	16.4	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	24.1	24.3	0.3	1.1%
		250	14.47	1.22	0.50	0.18	1.90	19.2	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.5	39.4	0.9	2.3%
		500	14.47	1.22	0.50	0.18	1.90	24.0	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.5	64.4	1.9	3.1%
		750	14.47	1.22	0.50	0.18	1.90	28.7	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.2	91.3	3.1	3.6%
		1,000	14.47	1.22	0.50	0.18	1.90	33.5	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.6	118.8	4.2	3.7%
		1,500	14.47	1.22	0.50	0.18	1.90	43.0	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.3	173.8	6.4	3.8%
		2,000	14.47	1.22	0.50	0.18	1.90	52.5	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	220.1	228.7	8.6	3.9%

New Rate Class: UR

Total Bill Impacts of Target Distribution Rates[new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Rates Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs	$	[$/month]	[$/month]	[$/month]	%
UR	Quinte West	100	**6.58**	**0.92**	**0.39**	**0.11**	**1.42**	8.0	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	15.7	24.3	8.6	55.0%
		250	6.58	0.92	0.39	0.11	1.42	10.1	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	29.4	39.4	10.0	34.0%
		500	6.58	0.92	0.39	0.11	1.42	13.7	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	52.2	64.4	12.2	23.4%
		750	6.58	0.92	0.39	0.11	1.42	17.2	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	76.7	91.3	14.6	19.1%
		1,000	6.58	0.92	0.39	0.11	1.42	20.8	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	101.9	118.8	16.9	16.6%
		1,500	6.58	0.92	0.39	0.11	1.42	27.9	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	152.2	173.8	21.5	14.1%
		2,000	6.58	0.92	0.39	0.11	1.42	35.0	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	202.6	228.7	26.1	12.9%
UR	Smiths Falls	100	**12.63**	**1.42**	**0.46**	**0.17**	**2.05**	14.7	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	22.4	24.3	2.0	8.7%
		250	12.63	1.42	0.46	0.17	2.05	17.8	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	37.0	39.4	2.4	6.4%
		500	12.63	1.42	0.46	0.17	2.05	22.9	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	61.4	64.4	3.0	4.9%
		750	12.63	1.42	0.46	0.17	2.05	28.0	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.5	91.3	3.9	4.4%
		1,000	12.63	1.42	0.46	0.17	2.05	33.1	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.2	118.8	4.6	4.0%
		1,500	12.63	1.42	0.46	0.17	2.05	43.4	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.7	173.8	6.0	3.6%
		2,000	12.63	1.42	0.46	0.17	2.05	53.6	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.2	228.7	7.5	3.4%
UR	Thorold	100	**13.68**	**1.47**	**0.41**	**0.14**	**2.02**	15.7	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	23.4	24.3	0.9	4.0%
		250	13.68	1.47	0.41	0.14	2.02	18.7	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.0	39.4	1.4	3.6%
		500	13.68	1.47	0.41	0.14	2.02	23.8	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.3	64.4	2.1	3.4%
		750	13.68	1.47	0.41	0.14	2.02	28.8	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.3	91.3	3.0	3.4%
		1,000	13.68	1.47	0.41	0.14	2.02	33.9	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	115.0	118.8	3.8	3.3%
		1,500	13.68	1.47	0.41	0.14	2.02	44.0	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.3	173.8	5.4	3.2%
		2,000	13.68	1.47	0.41	0.14	2.02	54.1	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.7	228.7	7.0	3.2%
UR	Whitchurch Stouffville	100	**10.54**	**1.02**	**0.36**	**0.12**	**1.50**	12.0	**14.32**	**2.29**		**(0.02)**	**2.27**	16.6	**0.92**	0.62	0.7	**1.078**	2.4	100	-	5.4	19.7	24.3	4.6	23.3%
		250	10.54	1.02	0.36	0.12	1.50	14.3	14.32	2.29	-	(0.02)	2.27	20.0	0.92	0.62	0.70	1.078	5.9	250	-	13.5	33.5	39.4	5.8	17.4%
		500	10.54	1.02	0.36	0.12	1.50	18.0	14.32	2.29	-	(0.02)	2.27	25.7	0.92	0.62	0.70	1.078	11.8	500	-	27.0	56.5	64.4	7.9	13.9%
		750	10.54	1.02	0.36	0.12	1.50	21.8	14.32	2.29	-	(0.02)	2.27	31.3	0.92	0.62	0.70	1.078	17.7	600	150	42.3	81.3	91.3	10.1	12.4%
		1,000	10.54	1.02	0.36	0.12	1.50	25.5	14.32	2.29	-	(0.02)	2.27	37.0	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.6	118.8	12.2	11.4%
		1,500	10.54	1.02	0.36	0.12	1.50	33.0	14.32	2.29	-	(0.02)	2.27	48.4	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.4	173.8	16.4	10.4%
		2,000	10.54	1.02	0.36	0.12	1.50	40.5	14.32	2.29	-	(0.02)	2.27	59.7	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.2	228.7	20.6	9.9%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	R1	100	**19.04**	**2.38**	**0.15**	**0.07**	**2.60**	21.6	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	29.5	29.4	(0.1)	-0.3%
		250	19.04	2.38	0.15	0.07	2.60	25.5	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	45.2	45.0	(0.2)	-0.5%
		500	19.04	2.38	0.15	0.07	2.60	32.0	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	71.4	70.9	(0.5)	-0.6%
		750	19.04	2.38	0.15	0.07	2.60	38.5	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	99.5	98.8	(0.7)	-0.7%
		1,000	19.04	2.38	0.15	0.07	2.60	45.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	128.1	127.1	(1.0)	-0.8%
		1,500	19.04	2.38	0.15	0.07	2.60	58.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	185.3	183.9	(1.5)	-0.8%
		2,000	19.04	2.38	0.15	0.07	2.60	71.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	242.6	240.6	(1.9)	-0.8%
R1	Ailsa Craig	100	**10.51**	**0.82**	**0.35**	**0.11**	**1.28**	11.8	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	19.5	29.4	9.9	50.9%
		250	10.51	0.82	0.35	0.11	1.28	13.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.0	45.0	12.0	36.4%
		500	10.51	0.82	0.35	0.11	1.28	16.9	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	55.4	70.9	15.5	27.9%
		750	10.51	0.82	0.35	0.11	1.28	20.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.6	98.8	19.2	24.1%
		1,000	10.51	0.82	0.35	0.11	1.28	23.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	104.4	127.1	22.7	21.8%
		1,500	10.51	0.82	0.35	0.11	1.28	29.7	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	154.1	183.9	29.8	19.3%
		2,000	10.51	0.82	0.35	0.11	1.28	36.1	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	203.7	240.6	36.9	18.1%
R1	Arkona	100	**5.84**	**0.26**	**0.68**	**0.33**	**1.27**	7.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.8	29.4	14.6	98.6%
		250	5.84	0.26	0.68	0.33	1.27	9.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.3	45.0	16.7	59.1%
		500	5.84	0.26	0.68	0.33	1.27	12.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	50.7	70.9	20.2	39.9%
		750	5.84	0.26	0.68	0.33	1.27	15.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	74.8	98.8	23.9	31.9%
		1,000	5.84	0.26	0.68	0.33	1.27	18.5	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	99.6	127.1	27.5	27.6%
		1,500	5.84	0.26	0.68	0.33	1.27	24.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	149.3	183.9	34.6	23.2%
		2,000	5.84	0.26	0.68	0.33	1.27	31.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	198.9	240.6	41.8	21.0%
UR	Arnprior	100	**11.54**	**1.47**	**0.49**	**0.18**	**2.14**	13.7	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	21.4	29.4	8.0	37.4%
		250	11.54	1.47	0.49	0.18	2.14	16.9	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	36.1	44.9	8.7	24.1%
		500	11.54	1.47	0.49	0.18	2.14	22.2	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	60.7	70.7	9.9	16.4%
		750	11.54	1.47	0.49	0.18	2.14	27.6	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.1	98.4	11.3	13.0%
		1,000	11.54	1.47	0.49	0.18	2.14	32.9	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.0	126.6	12.6	11.0%
		1,500	11.54	1.47	0.49	0.18	2.14	43.6	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.0	183.1	15.1	9.0%
		2,000	11.54	1.47	0.49	0.18	2.14	54.3	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	222.0	239.6	17.7	8.0%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Arran-Elders	100	9.02	0.95	0.35	0.15	1.45	10.5	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	18.2	29.4	11.2	61.9%
		250	9.02	0.95	0.35	0.15	1.45	12.6	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	31.9	45.0	13.1	41.0%
		500	9.02	0.95	0.35	0.15	1.45	16.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	54.8	70.9	16.1	29.4%
		750	9.02	0.95	0.35	0.15	1.45	19.9	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.4	98.8	19.4	24.4%
		1,000	9.02	0.95	0.35	0.15	1.45	23.5	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	104.6	127.1	22.5	21.5%
		1,500	9.02	0.95	0.35	0.15	1.45	30.8	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.1	183.9	28.7	18.5%
		2,000	9.02	0.95	0.35	0.15	1.45	38.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	205.6	240.6	35.0	17.0%
R1	Artemesia	100	12.73	0.93	0.59	0.34	1.86	14.6	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.3	29.4	7.1	31.9%
		250	12.73	0.93	0.59	0.34	1.86	17.4	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.6	45.0	8.3	22.8%
		500	12.73	0.93	0.59	0.34	1.86	22.0	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.5	70.9	10.4	17.1%
		750	12.73	0.93	0.59	0.34	1.86	26.7	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.2	98.8	12.6	14.6%
		1,000	12.73	0.93	0.59	0.34	1.86	31.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.4	127.1	14.7	13.1%
		1,500	12.73	0.93	0.59	0.34	1.86	40.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.0	183.9	18.9	11.4%
		2,000	12.73	0.93	0.59	0.34	1.86	49.9	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	217.5	240.6	23.1	10.6%
R1	Bancroft	100	13.48	0.95	0.34	0.12	1.41	14.9	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.6	29.4	6.8	30.2%
		250	13.48	0.95	0.34	0.12	1.41	17.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.3	45.0	8.7	24.0%
		500	13.48	0.95	0.34	0.12	1.41	20.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.0	70.9	11.9	20.1%
		750	13.48	0.95	0.34	0.12	1.41	24.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.5	98.8	15.2	18.2%
		1,000	13.48	0.95	0.34	0.12	1.41	27.6	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.7	127.1	18.4	17.0%
		1,500	13.48	0.95	0.34	0.12	1.41	34.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.0	183.9	24.9	15.7%
		2,000	13.48	0.95	0.34	0.12	1.41	41.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.3	240.6	31.3	15.0%
R1	Bath	100	13.38	0.86	0.68	0.38	1.92	15.3	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.0	29.4	6.4	27.9%
		250	13.38	0.86	0.68	0.38	1.92	18.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	45.0	7.5	20.1%
		500	13.38	0.86	0.68	0.38	1.92	23.0	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.5	70.9	9.4	15.3%
		750	13.38	0.86	0.68	0.38	1.92	27.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.3	98.8	11.5	13.2%
		1,000	13.38	0.86	0.68	0.38	1.92	32.6	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	113.7	127.1	13.4	11.8%
		1,500	13.38	0.86	0.68	0.38	1.92	42.2	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	166.5	183.9	17.3	10.4%
		2,000	13.38	0.86	0.68	0.38	1.92	51.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	219.4	240.6	21.2	9.7%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Blandford-B	100	11.63	0.90	0.63	0.33	1.86	13.5	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	21.2	29.4	8.2	38.8%
		250	11.63	0.90	0.63	0.33	1.86	16.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.5	45.0	9.4	26.6%
		500	11.63	0.90	0.63	0.33	1.86	20.9	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.4	70.9	11.5	19.3%
		750	11.63	0.90	0.63	0.33	1.86	25.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.1	98.8	13.7	16.1%
		1,000	11.63	0.90	0.63	0.33	1.86	30.2	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.3	127.1	15.8	14.2%
		1,500	11.63	0.90	0.63	0.33	1.86	39.5	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	163.9	183.9	20.0	12.2%
		2,000	11.63	0.90	0.63	0.33	1.86	48.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	216.4	240.6	24.2	11.2%
R1	Blyth	100	7.19	0.91	0.54	0.27	1.72	8.9	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	16.6	29.4	12.8	77.1%
		250	7.19	0.91	0.54	0.27	1.72	11.5	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	30.7	45.0	14.2	46.3%
		500	7.19	0.91	0.54	0.27	1.72	15.8	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	54.3	70.9	16.6	30.6%
		750	7.19	0.91	0.54	0.27	1.72	20.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.6	98.8	19.2	24.1%
		1,000	7.19	0.91	0.54	0.27	1.72	24.4	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.5	127.1	21.6	20.5%
		1,500	7.19	0.91	0.54	0.27	1.72	33.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	157.4	183.9	26.5	16.9%
		2,000	7.19	0.91	0.54	0.27	1.72	41.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.2	240.6	31.4	15.0%
R1	Bobcaygeor	100	14.47	0.97	0.28	0.10	1.35	15.8	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.5	29.4	5.9	25.0%
		250	14.47	0.97	0.28	0.10	1.35	17.8	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.1	45.0	7.9	21.2%
		500	14.47	0.97	0.28	0.10	1.35	21.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.7	70.9	11.2	18.7%
		750	14.47	0.97	0.28	0.10	1.35	24.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.1	98.8	14.7	17.5%
		1,000	14.47	0.97	0.28	0.10	1.35	28.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.1	127.1	18.1	16.6%
		1,500	14.47	0.97	0.28	0.10	1.35	34.7	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.1	183.9	24.8	15.6%
		2,000	14.47	0.97	0.28	0.10	1.35	41.5	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.1	240.6	31.5	15.1%
R1	Brighton	100	11.61	1.07	0.37	0.11	1.55	13.2	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	20.9	29.4	8.6	41.0%
		250	11.61	1.07	0.37	0.11	1.55	15.5	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.7	45.0	10.2	29.5%
		500	11.61	1.07	0.37	0.11	1.55	19.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.9	70.9	13.0	22.5%
		750	11.61	1.07	0.37	0.11	1.55	23.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	82.7	98.8	16.0	19.4%
		1,000	11.61	1.07	0.37	0.11	1.55	27.1	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.2	127.1	18.9	17.5%
		1,500	11.61	1.07	0.37	0.11	1.55	34.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.2	183.9	24.7	15.5%
		2,000	11.61	1.07	0.37	0.11	1.55	42.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.2	240.6	30.4	14.5%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UR	Brockville	100	12.33	0.93	0.48	0.16	1.57	13.9	19.04	2.60		(0.02)	2.58	21.6	0.92	0.62	0.70	1.078	2.4	100	-	5.4	21.6	29.4	7.8	36.0%
		250	12.33	0.93	0.48	0.16	1.57	16.3	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	35.5	44.9	9.4	26.3%
		500	12.33	0.93	0.48	0.16	1.57	20.2	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	58.7	70.7	12.0	20.4%
		750	12.33	0.93	0.48	0.16	1.57	24.1	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	83.6	98.4	14.8	17.7%
		1,000	12.33	0.93	0.48	0.16	1.57	28.0	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	109.1	126.6	17.5	16.0%
		1,500	12.33	0.93	0.48	0.16	1.57	35.9	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	160.2	183.1	22.9	14.3%
		2,000	12.33	0.93	0.48	0.16	1.57	43.7	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	211.3	239.6	28.3	13.4%
R1	Caledon CH	100	15.19	1.02	0.28	0.08	1.38	16.6	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	24.3	29.4	5.1	21.2%
		250	15.19	1.02	0.28	0.08	1.38	18.6	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.9	45.0	7.1	18.7%
		500	15.19	1.02	0.28	0.08	1.38	22.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.6	70.9	10.3	17.0%
		750	15.19	1.02	0.28	0.08	1.38	25.5	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.0	98.8	13.7	16.2%
		1,000	15.19	1.02	0.28	0.08	1.38	29.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.1	127.1	17.0	15.5%
		1,500	15.19	1.02	0.28	0.08	1.38	35.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.3	183.9	23.6	14.7%
		2,000	15.19	1.02	0.28	0.08	1.38	42.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.4	240.6	30.2	14.4%
R1	Campbellfor	100	12.30	1.07	0.41	0.12	1.60	13.9	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	21.6	29.4	7.8	36.2%
		250	12.30	1.07	0.41	0.12	1.60	16.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.6	45.0	9.4	26.5%
		500	12.30	1.07	0.41	0.12	1.60	20.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.8	70.9	12.1	20.6%
		750	12.30	1.07	0.41	0.12	1.60	24.3	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.8	98.8	15.0	17.9%
		1,000	12.30	1.07	0.41	0.12	1.60	28.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.4	127.1	17.7	16.2%
		1,500	12.30	1.07	0.41	0.12	1.60	36.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.7	183.9	23.2	14.4%
		2,000	12.30	1.07	0.41	0.12	1.60	44.3	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.9	240.6	28.7	13.5%
UR	Carleton Pla	100	14.17	1.79	0.38	0.15	2.32	16.5	19.04	2.60		(0.02)	2.58	21.6	0.92	0.62	0.70	1.078	2.4	100	-	5.4	24.2	29.4	5.2	21.4%
		250	14.17	1.79	0.38	0.15	2.32	20.0	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	44.9	5.6	14.4%
		500	14.17	1.79	0.38	0.15	2.32	25.8	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.3	70.7	6.4	10.0%
		750	14.17	1.79	0.38	0.15	2.32	31.6	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	91.1	98.4	7.3	8.0%
		1,000	14.17	1.79	0.38	0.15	2.32	37.4	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.5	126.6	8.1	6.9%
		1,500	14.17	1.79	0.38	0.15	2.32	49.0	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	173.3	183.1	9.8	5.6%
		2,000	14.17	1.79	0.38	0.15	2.32	60.6	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	228.2	239.6	11.4	5.0%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates						New Dx Rates										New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
								Existing Dx						New Dx	RTSR new	WMSC	DRC	TLF new		5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Cavan-Millbı	100	**15.01**	**1.34**	**0.68**	**0.40**	**2.42**	17.4	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.1	29.4	4.3	17.0%
		250	15.01	1.34	0.68	0.40	2.42	21.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.3	45.0	4.7	11.6%
		500	15.01	1.34	0.68	0.40	2.42	27.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	65.6	70.9	5.3	8.1%
		750	15.01	1.34	0.68	0.40	2.42	33.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	92.6	98.8	6.1	6.6%
		1,000	15.01	1.34	0.68	0.40	2.42	39.2	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	120.3	127.1	6.8	5.7%
		1,500	15.01	1.34	0.68	0.40	2.42	51.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	175.7	183.9	8.2	4.7%
		2,000	15.01	1.34	0.68	0.40	2.42	63.4	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	231.0	240.6	9.6	4.2%
R1	Centre Hasti	100	**11.67**	**0.96**	**0.29**	**0.11**	**1.36**	13.0	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.7	29.4	8.7	41.9%
		250	11.67	0.96	0.29	0.11	1.36	15.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.3	45.0	10.6	31.0%
		500	11.67	0.96	0.29	0.11	1.36	18.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.0	70.9	13.9	24.4%
		750	11.67	0.96	0.29	0.11	1.36	21.9	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.4	98.8	17.4	21.4%
		1,000	11.67	0.96	0.29	0.11	1.36	25.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.4	127.1	20.8	19.5%
		1,500	11.67	0.96	0.29	0.11	1.36	32.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.4	183.9	27.4	17.5%
		2,000	11.67	0.96	0.29	0.11	1.36	38.9	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	206.5	240.6	34.1	16.5%
R1	Chalk River	100	**14.03**	**1.37**	**0.61**	**0.42**	**2.40**	16.4	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.1	29.4	5.3	21.9%
		250	14.03	1.37	0.61	0.42	2.40	20.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.3	45.0	5.7	14.5%
		500	14.03	1.37	0.61	0.42	2.40	26.0	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.5	70.9	6.4	9.9%
		750	14.03	1.37	0.61	0.42	2.40	32.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.5	98.8	7.2	7.9%
		1,000	14.03	1.37	0.61	0.42	2.40	38.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	119.1	127.1	8.0	6.7%
		1,500	14.03	1.37	0.61	0.42	2.40	50.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	174.4	183.9	9.5	5.4%
		2,000	14.03	1.37	0.61	0.42	2.40	62.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	229.6	240.6	11.0	4.8%
R1	Champlain	100	**10.36**	**0.88**	**0.45**	**0.23**	**1.56**	11.9	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	19.6	29.4	9.8	49.9%
		250	10.36	0.88	0.45	0.23	1.56	14.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.5	45.0	11.5	34.2%
		500	10.36	0.88	0.45	0.23	1.56	18.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.7	70.9	14.2	25.1%
		750	10.36	0.88	0.45	0.23	1.56	22.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.5	98.8	17.2	21.1%
		1,000	10.36	0.88	0.45	0.23	1.56	26.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	107.1	127.1	20.1	18.7%
		1,500	10.36	0.88	0.45	0.23	1.56	33.8	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.1	183.9	25.8	16.3%
		2,000	10.36	0.88	0.45	0.23	1.56	41.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.2	240.6	31.4	15.0%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Cobden	100	**13.07**	**1.76**	**0.68**	**0.41**	**2.85**	15.9	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.6	29.4	5.8	24.5%
		250	13.07	1.76	0.68	0.41	2.85	20.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.4	45.0	5.5	14.0%
		500	13.07	1.76	0.68	0.41	2.85	27.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	65.8	70.9	5.1	7.7%
		750	13.07	1.76	0.68	0.41	2.85	34.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	93.9	98.8	4.8	5.1%
		1,000	13.07	1.76	0.68	0.41	2.85	41.6	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	122.7	127.1	4.5	3.6%
		1,500	13.07	1.76	0.68	0.41	2.85	55.8	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	180.2	183.9	3.7	2.1%
		2,000	13.07	1.76	0.68	0.41	2.85	70.1	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	237.7	240.6	2.9	1.2%
R1	Deep River	100	**16.62**	**2.29**	**0.38**	**0.25**	**2.92**	19.5	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	27.2	29.4	2.2	8.0%
		250	16.62	2.29	0.38	0.25	2.92	23.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	43.2	45.0	1.8	4.2%
		500	16.62	2.29	0.38	0.25	2.92	31.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	69.7	70.9	1.2	1.7%
		750	16.62	2.29	0.38	0.25	2.92	38.5	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	98.0	98.8	0.8	0.8%
		1,000	16.62	2.29	0.38	0.25	2.92	45.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	126.9	127.1	0.2	0.2%
		1,500	16.62	2.29	0.38	0.25	2.92	60.4	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	184.8	183.9	(0.9)	-0.5%
		2,000	16.62	2.29	0.38	0.25	2.92	75.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	242.6	240.6	(2.0)	-0.8%
R1	Deseronto	100	**12.89**	**1.12**	**0.37**	**0.11**	**1.60**	14.5	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	22.2	29.4	7.2	32.5%
		250	12.89	1.12	0.37	0.11	1.60	16.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.1	45.0	8.8	24.4%
		500	12.89	1.12	0.37	0.11	1.60	20.9	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.4	70.9	11.5	19.4%
		750	12.89	1.12	0.37	0.11	1.60	24.9	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.4	98.8	14.4	17.1%
		1,000	12.89	1.12	0.37	0.11	1.60	28.9	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.0	127.1	17.1	15.6%
		1,500	12.89	1.12	0.37	0.11	1.60	36.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	161.3	183.9	22.6	14.0%
		2,000	12.89	1.12	0.37	0.11	1.60	44.9	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	212.5	240.6	28.1	13.2%
UR	Dryden	100	**14.28**	**1.65**	**0.43**	**0.18**	**2.26**	16.5	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	24.2	29.4	5.1	21.1%
		250	14.28	1.65	0.43	0.18	2.26	19.9	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.2	44.9	5.7	14.5%
		500	14.28	1.65	0.43	0.18	2.26	25.6	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	64.1	70.7	6.6	10.3%
		750	14.28	1.65	0.43	0.18	2.26	31.2	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	90.7	98.4	7.7	8.5%
		1,000	14.28	1.65	0.43	0.18	2.26	36.9	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	118.0	126.6	8.6	7.3%
		1,500	14.28	1.65	0.43	0.18	2.26	48.2	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	172.5	183.1	10.6	6.1%
		2,000	14.28	1.65	0.43	0.18	2.26	59.5	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	227.1	239.6	12.5	5.5%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Dundalk	100	**14.47**	**1.08**	**0.39**	**0.13**	**1.60**	16.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.8	29.4	5.6	23.7%
		250	14.47	1.08	0.39	0.13	1.60	18.5	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.7	45.0	7.2	19.2%
		500	14.47	1.08	0.39	0.13	1.60	22.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.0	70.9	9.9	16.3%
		750	14.47	1.08	0.39	0.13	1.60	26.5	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.0	98.8	12.8	14.9%
		1,000	14.47	1.08	0.39	0.13	1.60	30.5	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.6	127.1	15.6	13.9%
		1,500	14.47	1.08	0.39	0.13	1.60	38.5	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.8	183.9	21.0	12.9%
		2,000	14.47	1.08	0.39	0.13	1.60	46.5	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.1	240.6	26.5	12.4%
R1	Durham	100	**16.35**	**1.24**	**0.46**	**0.16**	**1.86**	18.2	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.9	29.4	3.5	13.5%
		250	16.35	1.24	0.46	0.16	1.86	21.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.3	45.0	4.7	11.7%
		500	16.35	1.24	0.46	0.16	1.86	25.7	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.2	70.9	6.7	10.5%
		750	16.35	1.24	0.46	0.16	1.86	30.3	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	89.8	98.8	9.0	10.0%
		1,000	16.35	1.24	0.46	0.16	1.86	35.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	116.1	127.1	11.1	9.5%
		1,500	16.35	1.24	0.46	0.16	1.86	44.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.6	183.9	15.3	9.1%
		2,000	16.35	1.24	0.46	0.16	1.86	53.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	221.2	240.6	19.5	8.8%
R1	Eganville	100	**13.86**	**1.53**	**0.29**	**0.12**	**1.94**	15.8	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.5	29.4	5.9	25.2%
		250	13.86	1.53	0.29	0.12	1.94	18.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.0	45.0	7.0	18.5%
		500	13.86	1.53	0.29	0.12	1.94	23.6	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	62.1	70.9	8.8	14.2%
		750	13.86	1.53	0.29	0.12	1.94	28.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.9	98.8	10.9	12.4%
		1,000	13.86	1.53	0.29	0.12	1.94	33.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.4	127.1	12.8	11.2%
		1,500	13.86	1.53	0.29	0.12	1.94	43.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	167.3	183.9	16.6	9.9%
		2,000	13.86	1.53	0.29	0.12	1.94	52.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	220.3	240.6	20.3	9.2%
R1	Erin	100	**13.13**	**1.90**	**0.83**	**0.40**	**3.13**	16.3	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.0	29.4	5.5	22.7%
		250	13.13	1.90	0.83	0.40	3.13	21.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.2	45.0	4.8	11.8%
		500	13.13	1.90	0.83	0.40	3.13	28.8	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	67.3	70.9	3.6	5.4%
		750	13.13	1.90	0.83	0.40	3.13	36.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	96.1	98.8	2.7	2.8%
		1,000	13.13	1.90	0.83	0.40	3.13	44.4	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	125.5	127.1	1.6	1.3%
		1,500	13.13	1.90	0.83	0.40	3.13	60.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	184.4	183.9	(0.6)	-0.3%
		2,000	13.13	1.90	0.83	0.40	3.13	75.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	243.3	240.6	(2.7)	-1.1%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Exeter	100	**15.10**	**0.96**	**0.45**	**0.15**	**1.56**	16.7	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.4	29.4	5.1	20.7%
		250	15.10	0.96	0.45	0.15	1.56	19.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.3	45.0	6.7	17.6%
		500	15.10	0.96	0.45	0.15	1.56	22.9	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.4	70.9	9.5	15.5%
		750	15.10	0.96	0.45	0.15	1.56	26.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.3	98.8	12.5	14.5%
		1,000	15.10	0.96	0.45	0.15	1.56	30.7	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.8	127.1	15.3	13.7%
		1,500	15.10	0.96	0.45	0.15	1.56	38.5	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.9	183.9	21.0	12.9%
		2,000	15.10	0.96	0.45	0.15	1.56	46.3	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	213.9	240.6	26.7	12.5%
R1	Fenelon Fall	100	**6.09**	**0.96**	**0.25**	**0.08**	**1.29**	7.4	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	15.1	29.4	14.3	95.0%
		250	6.09	0.96	0.25	0.08	1.29	9.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.6	45.0	16.4	57.4%
		500	6.09	0.96	0.25	0.08	1.29	12.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	51.0	70.9	19.9	38.9%
		750	6.09	0.96	0.25	0.08	1.29	15.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	75.2	98.8	23.5	31.2%
		1,000	6.09	0.96	0.25	0.08	1.29	19.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	100.1	127.1	27.0	27.0%
		1,500	6.09	0.96	0.25	0.08	1.29	25.4	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	149.8	183.9	34.1	22.7%
		2,000	6.09	0.96	0.25	0.08	1.29	31.9	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	199.5	240.6	41.1	20.6%
R1	Forest	100	**15.26**	**0.95**	**0.41**	**0.15**	**1.51**	16.8	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.5	29.4	4.9	20.2%
		250	15.26	0.95	0.41	0.15	1.51	19.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.3	45.0	6.7	17.5%
		500	15.26	0.95	0.41	0.15	1.51	22.8	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.3	70.9	9.6	15.6%
		750	15.26	0.95	0.41	0.15	1.51	26.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.1	98.8	12.7	14.7%
		1,000	15.26	0.95	0.41	0.15	1.51	30.4	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.5	127.1	15.7	14.1%
		1,500	15.26	0.95	0.41	0.15	1.51	37.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.3	183.9	21.6	13.3%
		2,000	15.26	0.95	0.41	0.15	1.51	45.5	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	213.1	240.6	27.5	12.9%
UR	GBE	100	**9.68**	**0.95**	**0.46**	**0.13**	**1.54**	11.2	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	18.9	29.4	10.4	55.2%
		250	9.68	0.95	0.46	0.13	1.54	13.5	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	32.8	44.9	12.1	36.8%
		500	9.68	0.95	0.46	0.13	1.54	17.4	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	55.9	70.7	14.8	26.5%
		750	9.68	0.95	0.46	0.13	1.54	21.2	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	80.7	98.4	17.7	21.9%
		1,000	9.68	0.95	0.46	0.13	1.54	25.1	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.2	126.6	20.4	19.2%
		1,500	9.68	0.95	0.46	0.13	1.54	32.8	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.1	183.1	26.0	16.5%
		2,000	9.68	0.95	0.46	0.13	1.54	40.5	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.1	239.6	31.5	15.1%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Georgina	100	**11.72**	**0.98**	**0.31**	**0.09**	**1.38**	13.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.8	29.4	8.6	41.4%
		250	11.72	0.98	0.31	0.09	1.38	15.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.4	45.0	10.5	30.6%
		500	11.72	0.98	0.31	0.09	1.38	18.6	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.1	70.9	13.8	24.1%
		750	11.72	0.98	0.31	0.09	1.38	22.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.6	98.8	17.2	21.1%
		1,000	11.72	0.98	0.31	0.09	1.38	25.5	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.6	127.1	20.5	19.2%
		1,500	11.72	0.98	0.31	0.09	1.38	32.4	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.8	183.9	27.1	17.3%
		2,000	11.72	0.98	0.31	0.09	1.38	39.3	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	206.9	240.6	33.7	16.3%
R1	Glencoe	100	**12.90**	**0.77**	**0.89**	**0.43**	**2.09**	15.0	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	22.7	29.4	6.7	29.6%
		250	12.90	0.77	0.89	0.43	2.09	18.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	45.0	7.6	20.3%
		500	12.90	0.77	0.89	0.43	2.09	23.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.9	70.9	9.0	14.6%
		750	12.90	0.77	0.89	0.43	2.09	28.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	88.1	98.8	10.7	12.2%
		1,000	12.90	0.77	0.89	0.43	2.09	33.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.9	127.1	12.2	10.6%
		1,500	12.90	0.77	0.89	0.43	2.09	44.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.6	183.9	15.3	9.1%
		2,000	12.90	0.77	0.89	0.43	2.09	54.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	222.3	240.6	18.3	8.2%
R1	Grand Bend	100	**13.58**	**0.87**	**0.42**	**0.13**	**1.42**	15.0	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	22.7	29.4	6.7	29.6%
		250	13.58	0.87	0.42	0.13	1.42	17.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.4	45.0	8.6	23.6%
		500	13.58	0.87	0.42	0.13	1.42	20.7	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.2	70.9	11.7	19.8%
		750	13.58	0.87	0.42	0.13	1.42	24.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.7	98.8	15.0	18.0%
		1,000	13.58	0.87	0.42	0.13	1.42	27.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.9	127.1	18.2	16.8%
		1,500	13.58	0.87	0.42	0.13	1.42	34.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.2	183.9	24.6	15.5%
		2,000	13.58	0.87	0.42	0.13	1.42	42.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.6	240.6	31.0	14.8%
R1	Hastings	100	**16.44**	**1.35**	**0.37**	**0.12**	**1.84**	18.3	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	26.0	29.4	3.4	13.2%
		250	16.44	1.35	0.37	0.12	1.84	21.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.3	45.0	4.7	11.6%
		500	16.44	1.35	0.37	0.12	1.84	25.6	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.1	70.9	6.8	10.5%
		750	16.44	1.35	0.37	0.12	1.84	30.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	89.7	98.8	9.0	10.1%
		1,000	16.44	1.35	0.37	0.12	1.84	34.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	115.9	127.1	11.2	9.6%
		1,500	16.44	1.35	0.37	0.12	1.84	44.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.4	183.9	15.5	9.2%
		2,000	16.44	1.35	0.37	0.12	1.84	53.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	220.9	240.6	19.8	9.0%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Havelock	100	**15.17**	**1.14**	**0.32**	**0.13**	**1.59**	16.8	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.5	29.4	5.0	20.2%
		250	15.17	1.14	0.32	0.13	1.59	19.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.4	45.0	6.6	17.1%
		500	15.17	1.14	0.32	0.13	1.59	23.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.6	70.9	9.3	15.0%
		750	15.17	1.14	0.32	0.13	1.59	27.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.6	98.8	12.2	14.1%
		1,000	15.17	1.14	0.32	0.13	1.59	31.1	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.2	127.1	15.0	13.3%
		1,500	15.17	1.14	0.32	0.13	1.59	39.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	163.4	183.9	20.5	12.5%
		2,000	15.17	1.14	0.32	0.13	1.59	47.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.6	240.6	26.0	12.1%
R1	Kirkfield	100	**5.34**	**1.00**	**0.48**	**0.26**	**1.74**	7.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.8	29.4	14.6	99.0%
		250	5.34	1.00	0.48	0.26	1.74	9.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.9	45.0	16.0	55.4%
		500	5.34	1.00	0.48	0.26	1.74	14.0	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	52.5	70.9	18.4	34.9%
		750	5.34	1.00	0.48	0.26	1.74	18.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	77.9	98.8	20.9	26.8%
		1,000	5.34	1.00	0.48	0.26	1.74	22.7	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	103.8	127.1	23.3	22.4%
		1,500	5.34	1.00	0.48	0.26	1.74	31.4	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.8	183.9	28.1	18.0%
		2,000	5.34	1.00	0.48	0.26	1.74	40.1	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	207.8	240.6	32.9	15.8%
R1	Lanark High	100	**11.31**	**1.02**	**0.56**	**0.40**	**1.98**	13.3	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.0	29.4	8.4	40.1%
		250	11.31	1.02	0.56	0.40	1.98	16.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.5	45.0	9.5	26.6%
		500	11.31	1.02	0.56	0.40	1.98	21.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.7	70.9	11.2	18.7%
		750	11.31	1.02	0.56	0.40	1.98	26.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.6	98.8	13.1	15.3%
		1,000	11.31	1.02	0.56	0.40	1.98	31.1	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.2	127.1	14.9	13.3%
		1,500	11.31	1.02	0.56	0.40	1.98	41.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.4	183.9	18.5	11.2%
		2,000	11.31	1.02	0.56	0.40	1.98	50.9	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.5	240.6	22.1	10.1%
R1	Larder Lake	100	**15.84**	**1.01**	**0.68**	**0.43**	**2.12**	18.0	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.7	29.4	3.8	14.6%
		250	15.84	1.01	0.68	0.43	2.12	21.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.4	45.0	4.6	11.3%
		500	15.84	1.01	0.68	0.43	2.12	26.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.9	70.9	6.0	9.2%
		750	15.84	1.01	0.68	0.43	2.12	31.7	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.2	98.8	7.5	8.3%
		1,000	15.84	1.01	0.68	0.43	2.12	37.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.1	127.1	9.0	7.6%
		1,500	15.84	1.01	0.68	0.43	2.12	47.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	172.0	183.9	11.9	6.9%
		2,000	15.84	1.01	0.68	0.43	2.12	58.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	225.9	240.6	14.8	6.5%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates						New Dx Rates										New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
								Existing Dx						New Dx	RTSR new	WMSC	DRC	TLF new		5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Latchford	100	**13.31**	**0.88**	**1.04**	**0.45**	**2.37**	15.7	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.4	29.4	6.0	25.8%
		250	13.31	0.88	1.04	0.45	2.37	19.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.5	45.0	6.5	16.8%
		500	13.31	0.88	1.04	0.45	2.37	25.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.7	70.9	7.2	11.4%
		750	13.31	0.88	1.04	0.45	2.37	31.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.6	98.8	8.2	9.0%
		1,000	13.31	0.88	1.04	0.45	2.37	37.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.1	127.1	9.0	7.6%
		1,500	13.31	0.88	1.04	0.45	2.37	48.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.2	183.9	10.7	6.2%
		2,000	13.31	0.88	1.04	0.45	2.37	60.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.3	240.6	12.3	5.4%
UR	Lindsay	100	**15.81**	**1.01**	**0.41**	**0.14**	**1.56**	17.4	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	25.1	29.4	4.3	17.1%
		250	15.81	1.01	0.41	0.14	1.56	19.7	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	39.0	44.9	5.9	15.1%
		500	15.81	1.01	0.41	0.14	1.56	23.6	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.1	70.7	8.6	13.8%
		750	15.81	1.01	0.41	0.14	1.56	27.5	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.0	98.4	11.4	13.1%
		1,000	15.81	1.01	0.41	0.14	1.56	31.4	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	112.5	126.6	14.1	12.5%
		1,500	15.81	1.01	0.41	0.14	1.56	39.2	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	163.6	183.1	19.5	11.9%
		2,000	15.81	1.01	0.41	0.14	1.56	47.0	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	214.6	239.6	25.0	11.6%
R1	Lucan Grant	100	**11.72**	**1.42**	**0.37**	**0.17**	**1.96**	13.7	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.4	29.4	8.0	37.6%
		250	11.72	1.42	0.37	0.17	1.96	16.6	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.9	45.0	9.1	25.4%
		500	11.72	1.42	0.37	0.17	1.96	21.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.0	70.9	10.9	18.1%
		750	11.72	1.42	0.37	0.17	1.96	26.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.9	98.8	12.9	15.0%
		1,000	11.72	1.42	0.37	0.17	1.96	31.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.4	127.1	14.7	13.1%
		1,500	11.72	1.42	0.37	0.17	1.96	41.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.5	183.9	18.4	11.1%
		2,000	11.72	1.42	0.37	0.17	1.96	50.9	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.5	240.6	22.1	10.1%
R1	Malahide	100	**11.17**	**0.87**	**0.78**	**0.34**	**1.99**	13.2	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.9	29.4	8.6	41.0%
		250	11.17	0.87	0.78	0.34	1.99	16.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.4	45.0	9.6	27.0%
		500	11.17	0.87	0.78	0.34	1.99	21.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.6	70.9	11.3	18.9%
		750	11.17	0.87	0.78	0.34	1.99	26.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.6	98.8	13.2	15.4%
		1,000	11.17	0.87	0.78	0.34	1.99	31.1	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.2	127.1	15.0	13.3%
		1,500	11.17	0.87	0.78	0.34	1.99	41.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	165.4	183.9	18.5	11.2%
		2,000	11.17	0.87	0.78	0.34	1.99	51.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.6	240.6	22.0	10.1%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates						New Dx Rates										New	Band 1	Band 2	New				
								Existing Dx						New Dx	RTSR new	WMSC	DRC	TLF new		5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		Total Bill	Total Bill	Total Bill	Total Bill
																							[$/month]	[$/month]	[$/month]	%
R1	Mapleton	100	13.47	0.92	0.65	0.39	1.96	15.4	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.1	29.4	6.3	27.2%
		250	13.47	0.92	0.65	0.39	1.96	18.4	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.6	45.0	7.3	19.5%
		500	13.47	0.92	0.65	0.39	1.96	23.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.8	70.9	9.1	14.8%
		750	13.47	0.92	0.65	0.39	1.96	28.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.7	98.8	11.1	12.7%
		1,000	13.47	0.92	0.65	0.39	1.96	33.1	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.2	127.1	13.0	11.3%
		1,500	13.47	0.92	0.65	0.39	1.96	42.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	167.2	183.9	16.6	10.0%
		2,000	13.47	0.92	0.65	0.39	1.96	52.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	220.3	240.6	20.3	9.2%
R1	Markdale	100	14.30	0.86	0.44	0.16	1.46	15.8	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.5	29.4	6.0	25.4%
		250	14.30	0.86	0.44	0.16	1.46	18.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.2	45.0	7.8	20.9%
		500	14.30	0.86	0.44	0.16	1.46	21.6	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.1	70.9	10.8	18.0%
		750	14.30	0.86	0.44	0.16	1.46	25.3	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.7	98.8	14.0	16.6%
		1,000	14.30	0.86	0.44	0.16	1.46	28.9	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.0	127.1	17.1	15.6%
		1,500	14.30	0.86	0.44	0.16	1.46	36.2	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.6	183.9	23.3	14.5%
		2,000	14.30	0.86	0.44	0.16	1.46	43.5	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.1	240.6	29.5	14.0%
R1	Marmora	100	11.59	0.92	0.33	0.11	1.36	13.0	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	20.7	29.4	8.8	42.4%
		250	11.59	0.92	0.33	0.11	1.36	15.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.2	45.0	10.7	31.3%
		500	11.59	0.92	0.33	0.11	1.36	18.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.9	70.9	14.0	24.6%
		750	11.59	0.92	0.33	0.11	1.36	21.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.3	98.8	17.5	21.5%
		1,000	11.59	0.92	0.33	0.11	1.36	25.2	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.3	127.1	20.8	19.6%
		1,500	11.59	0.92	0.33	0.11	1.36	32.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.4	183.9	27.5	17.6%
		2,000	11.59	0.92	0.33	0.11	1.36	38.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	206.4	240.6	34.2	16.6%
R1	McGarry	100	12.85	0.93	0.71	0.45	2.09	14.9	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.6	29.4	6.8	29.9%
		250	12.85	0.93	0.71	0.45	2.09	18.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.3	45.0	7.6	20.5%
		500	12.85	0.93	0.71	0.45	2.09	23.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.8	70.9	9.1	14.7%
		750	12.85	0.93	0.71	0.45	2.09	28.5	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	88.0	98.8	10.8	12.2%
		1,000	12.85	0.93	0.71	0.45	2.09	33.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	114.9	127.1	12.3	10.7%
		1,500	12.85	0.93	0.71	0.45	2.09	44.2	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	168.6	183.9	15.3	9.1%
		2,000	12.85	0.93	0.71	0.45	2.09	54.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	222.3	240.6	18.4	8.3%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Meaford	100	12.75	0.97	0.40	0.12	1.49	14.2	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	21.9	29.4	7.5	34.0%
		250	12.75	0.97	0.40	0.12	1.49	16.5	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.7	45.0	9.2	25.9%
		500	12.75	0.97	0.40	0.12	1.49	20.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.7	70.9	12.2	20.8%
		750	12.75	0.97	0.40	0.12	1.49	23.9	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.4	98.8	15.4	18.4%
		1,000	12.75	0.97	0.40	0.12	1.49	27.7	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.8	127.1	18.4	16.9%
		1,500	12.75	0.97	0.40	0.12	1.49	35.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.5	183.9	24.4	15.3%
		2,000	12.75	0.97	0.40	0.12	1.49	42.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.2	240.6	30.5	14.5%
R1	Middlesex C	100	14.19	0.78	0.65	0.40	1.83	16.0	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.7	29.4	5.7	24.0%
		250	14.19	0.78	0.65	0.40	1.83	18.8	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.0	45.0	7.0	18.3%
		500	14.19	0.78	0.65	0.40	1.83	23.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.8	70.9	9.1	14.6%
		750	14.19	0.78	0.65	0.40	1.83	27.9	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.4	98.8	11.4	13.0%
		1,000	14.19	0.78	0.65	0.40	1.83	32.5	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	113.6	127.1	13.5	11.9%
		1,500	14.19	0.78	0.65	0.40	1.83	41.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	166.0	183.9	17.9	10.8%
		2,000	14.19	0.78	0.65	0.40	1.83	50.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	218.4	240.6	22.2	10.2%
R1	Napanee	100	14.70	1.02	0.43	0.14	1.59	16.3	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	24.0	29.4	5.4	22.6%
		250	14.70	1.02	0.43	0.14	1.59	18.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.9	45.0	7.0	18.6%
		500	14.70	1.02	0.43	0.14	1.59	22.7	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.2	70.9	9.7	15.9%
		750	14.70	1.02	0.43	0.14	1.59	26.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.1	98.8	12.7	14.7%
		1,000	14.70	1.02	0.43	0.14	1.59	30.6	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.7	127.1	15.4	13.8%
		1,500	14.70	1.02	0.43	0.14	1.59	38.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.9	183.9	21.0	12.9%
		2,000	14.70	1.02	0.43	0.14	1.59	46.5	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.1	240.6	26.5	12.4%
R1	Nipigon	100	14.23	1.42	1.27	0.72	3.41	17.6	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	25.3	29.4	4.1	16.1%
		250	14.23	1.42	1.27	0.72	3.41	22.8	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	42.0	45.0	3.0	7.1%
		500	14.23	1.42	1.27	0.72	3.41	31.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	69.8	70.9	1.1	1.6%
		750	14.23	1.42	1.27	0.72	3.41	39.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	99.3	98.8	(0.5)	-0.5%
		1,000	14.23	1.42	1.27	0.72	3.41	48.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	129.4	127.1	(2.3)	-1.8%
		1,500	14.23	1.42	1.27	0.72	3.41	65.4	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	189.7	183.9	(5.9)	-3.1%
		2,000	14.23	1.42	1.27	0.72	3.41	82.4	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	250.0	240.6	(9.4)	-3.8%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates						New Dx Rates										New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
								Existing Dx						New Dx	RTSR new	WMSC	DRC	TLF new		5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	North Dorch	100	**8.97**	**0.86**	**0.67**	**0.40**	**1.93**	10.9	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	18.6	29.4	10.8	58.1%
		250	8.97	0.86	0.67	0.40	1.93	13.8	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.0	45.0	11.9	36.1%
		500	8.97	0.86	0.67	0.40	1.93	18.6	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.1	70.9	13.8	24.1%
		750	8.97	0.86	0.67	0.40	1.93	23.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	82.9	98.8	15.8	19.1%
		1,000	8.97	0.86	0.67	0.40	1.93	28.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.4	127.1	17.8	16.2%
		1,500	8.97	0.86	0.67	0.40	1.93	37.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.3	183.9	21.6	13.3%
		2,000	8.97	0.86	0.67	0.40	1.93	47.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	215.2	240.6	25.4	11.8%
R1	North Dunda	100	**11.17**	**0.97**	**0.55**	**0.14**	**1.66**	12.8	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.5	29.4	8.9	43.3%
		250	11.17	0.97	0.55	0.14	1.66	15.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.6	45.0	10.4	30.1%
		500	11.17	0.97	0.55	0.14	1.66	19.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.0	70.9	12.9	22.3%
		750	11.17	0.97	0.55	0.14	1.66	23.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.1	98.8	15.7	18.8%
		1,000	11.17	0.97	0.55	0.14	1.66	27.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	108.9	127.1	18.3	16.8%
		1,500	11.17	0.97	0.55	0.14	1.66	36.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	160.4	183.9	23.4	14.6%
		2,000	11.17	0.97	0.55	0.14	1.66	44.4	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	212.0	240.6	28.6	13.5%
R1	North Gleng	100	**7.74**	**1.02**	**0.52**	**0.22**	**1.76**	9.5	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	17.2	29.4	12.2	71.0%
		250	7.74	1.02	0.52	0.22	1.76	12.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	31.4	45.0	13.6	43.2%
		500	7.74	1.02	0.52	0.22	1.76	16.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	55.0	70.9	15.9	28.8%
		750	7.74	1.02	0.52	0.22	1.76	20.9	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	80.4	98.8	18.3	22.8%
		1,000	7.74	1.02	0.52	0.22	1.76	25.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.4	127.1	20.7	19.4%
		1,500	7.74	1.02	0.52	0.22	1.76	34.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.5	183.9	25.4	16.0%
		2,000	7.74	1.02	0.52	0.22	1.76	42.9	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.6	240.6	30.1	14.3%
R1	North Grenv	100	**14.40**	**1.65**	**0.37**	**0.16**	**2.18**	16.6	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.3	29.4	5.1	21.1%
		250	14.40	1.65	0.37	0.16	2.18	19.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.1	45.0	5.9	15.0%
		500	14.40	1.65	0.37	0.16	2.18	25.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.8	70.9	7.1	11.1%
		750	14.40	1.65	0.37	0.16	2.18	30.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.2	98.8	8.5	9.5%
		1,000	14.40	1.65	0.37	0.16	2.18	36.2	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	117.3	127.1	9.8	8.4%
		1,500	14.40	1.65	0.37	0.16	2.18	47.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	171.5	183.9	12.4	7.2%
		2,000	14.40	1.65	0.37	0.16	2.18	58.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	225.6	240.6	15.0	6.7%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates						New Dx Rates										New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
								Existing Dx						New Dx	RTSR new	WMSC	DRC	TLF new		5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	North Perth	100	**14.73**	**1.05**	**0.47**	**0.16**	**1.68**	16.4	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.1	29.4	5.3	22.0%
		250	14.73	1.05	0.47	0.16	1.68	18.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.2	45.0	6.8	17.8%
		500	14.73	1.05	0.47	0.16	1.68	23.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.6	70.9	9.3	15.0%
		750	14.73	1.05	0.47	0.16	1.68	27.3	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.8	98.8	11.9	13.8%
		1,000	14.73	1.05	0.47	0.16	1.68	31.5	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.6	127.1	14.5	12.9%
		1,500	14.73	1.05	0.47	0.16	1.68	39.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	164.3	183.9	19.6	11.9%
		2,000	14.73	1.05	0.47	0.16	1.68	48.3	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	215.9	240.6	24.7	11.4%
R1	North Storm	100	**5.42**	**0.92**	**0.62**	**0.36**	**1.90**	7.3	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	15.0	29.4	14.4	95.8%
		250	5.42	0.92	0.62	0.36	1.90	10.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	29.4	45.0	15.5	52.8%
		500	5.42	0.92	0.62	0.36	1.90	14.9	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	53.4	70.9	17.5	32.7%
		750	5.42	0.92	0.62	0.36	1.90	19.7	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.2	98.8	19.6	24.8%
		1,000	5.42	0.92	0.62	0.36	1.90	24.4	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.5	127.1	21.6	20.5%
		1,500	5.42	0.92	0.62	0.36	1.90	33.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.3	183.9	25.6	16.2%
		2,000	5.42	0.92	0.62	0.36	1.90	43.4	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.0	240.6	29.6	14.0%
R1	Omemee	100	**14.99**	**1.50**	**0.36**	**0.14**	**2.00**	17.0	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.7	29.4	4.7	19.1%
		250	14.99	1.50	0.36	0.14	2.00	20.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.2	45.0	5.7	14.6%
		500	14.99	1.50	0.36	0.14	2.00	25.0	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.5	70.9	7.4	11.7%
		750	14.99	1.50	0.36	0.14	2.00	30.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	89.5	98.8	9.3	10.4%
		1,000	14.99	1.50	0.36	0.14	2.00	35.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	116.1	127.1	11.0	9.5%
		1,500	14.99	1.50	0.36	0.14	2.00	45.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	169.4	183.9	14.5	8.6%
		2,000	14.99	1.50	0.36	0.14	2.00	55.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	222.6	240.6	18.0	8.1%
UR	Perth	100	**14.47**	**1.22**	**0.50**	**0.18**	**1.90**	16.4	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	24.1	29.4	5.3	22.0%
		250	14.47	1.22	0.50	0.18	1.90	19.2	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.5	44.9	6.4	16.6%
		500	14.47	1.22	0.50	0.18	1.90	24.0	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.5	70.7	8.2	13.1%
		750	14.47	1.22	0.50	0.18	1.90	28.7	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.2	98.4	10.2	11.5%
		1,000	14.47	1.22	0.50	0.18	1.90	33.5	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.6	126.6	12.0	10.5%
		1,500	14.47	1.22	0.50	0.18	1.90	43.0	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.3	183.1	15.8	9.4%
		2,000	14.47	1.22	0.50	0.18	1.90	52.5	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	220.1	239.6	19.5	8.9%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates						New Dx Rates										New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
								Existing Dx						New Dx	RTSR new	WMSC	DRC	TLF new		5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Perth East	100	**5.95**	**0.78**	**0.26**	**0.06**	**1.10**	7.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.8	29.4	14.7	99.4%
		250	5.95	0.78	0.26	0.06	1.10	8.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.0	45.0	17.0	60.9%
		500	5.95	0.78	0.26	0.06	1.10	11.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	50.0	70.9	20.9	41.9%
		750	5.95	0.78	0.26	0.06	1.10	14.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	73.7	98.8	25.1	34.0%
		1,000	5.95	0.78	0.26	0.06	1.10	17.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	98.1	127.1	29.1	29.6%
		1,500	5.95	0.78	0.26	0.06	1.10	22.5	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	146.8	183.9	37.1	25.2%
		2,000	5.95	0.78	0.26	0.06	1.10	28.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	195.6	240.6	45.1	23.0%
R1	Prince Edwa	100	**14.25**	**1.05**	**0.39**	**0.13**	**1.57**	15.8	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.5	29.4	5.9	25.0%
		250	14.25	1.05	0.39	0.13	1.57	18.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	45.0	7.5	20.2%
		500	14.25	1.05	0.39	0.13	1.57	22.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.6	70.9	10.3	17.0%
		750	14.25	1.05	0.39	0.13	1.57	26.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.5	98.8	13.3	15.5%
		1,000	14.25	1.05	0.39	0.13	1.57	30.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.1	127.1	16.1	14.5%
		1,500	14.25	1.05	0.39	0.13	1.57	37.8	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.2	183.9	21.7	13.4%
		2,000	14.25	1.05	0.39	0.13	1.57	45.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	213.3	240.6	27.4	12.8%
UR	Quinte West	100	**6.58**	**0.92**	**0.39**	**0.11**	**1.42**	8.0	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	15.7	29.4	13.7	87.0%
		250	6.58	0.92	0.39	0.11	1.42	10.1	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	29.4	44.9	15.5	52.7%
		500	6.58	0.92	0.39	0.11	1.42	13.7	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	52.2	70.7	18.5	35.4%
		750	6.58	0.92	0.39	0.11	1.42	17.2	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	76.7	98.4	21.7	28.2%
		1,000	6.58	0.92	0.39	0.11	1.42	20.8	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	101.9	126.6	24.7	24.3%
		1,500	6.58	0.92	0.39	0.11	1.42	27.9	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	152.2	183.1	30.9	20.3%
		2,000	6.58	0.92	0.39	0.11	1.42	35.0	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	202.6	239.6	37.0	18.3%
R1	Rainy River	100	**15.04**	**1.02**	**0.75**	**0.50**	**2.27**	17.3	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.0	29.4	4.4	17.6%
		250	15.04	1.02	0.75	0.50	2.27	20.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.0	45.0	5.0	12.5%
		500	15.04	1.02	0.75	0.50	2.27	26.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.9	70.9	6.0	9.3%
		750	15.04	1.02	0.75	0.50	2.27	32.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.5	98.8	7.2	7.9%
		1,000	15.04	1.02	0.75	0.50	2.27	37.7	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.8	127.1	8.3	7.0%
		1,500	15.04	1.02	0.75	0.50	2.27	49.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.5	183.9	10.4	6.0%
		2,000	15.04	1.02	0.75	0.50	2.27	60.4	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.1	240.6	12.6	5.5%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Ramara	100	6.52	0.95	0.55	0.35	1.85	8.4	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	16.1	29.4	13.3	83.0%
		250	6.52	0.95	0.55	0.35	1.85	11.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	30.4	45.0	14.6	47.9%
		500	6.52	0.95	0.55	0.35	1.85	15.8	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	54.3	70.9	16.6	30.6%
		750	6.52	0.95	0.55	0.35	1.85	20.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.9	98.8	18.9	23.6%
		1,000	6.52	0.95	0.55	0.35	1.85	25.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.1	127.1	21.0	19.8%
		1,500	6.52	0.95	0.55	0.35	1.85	34.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.6	183.9	25.2	15.9%
		2,000	6.52	0.95	0.55	0.35	1.85	43.5	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	211.1	240.6	29.5	14.0%
R1	Red Rock	100	15.21	2.07	0.77	0.54	3.38	18.6	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	26.3	29.4	3.1	11.9%
		250	15.21	2.07	0.77	0.54	3.38	23.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	42.9	45.0	2.1	4.8%
		500	15.21	2.07	0.77	0.54	3.38	32.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	70.6	70.9	0.3	0.4%
		750	15.21	2.07	0.77	0.54	3.38	40.6	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	100.0	98.8	(1.3)	-1.3%
		1,000	15.21	2.07	0.77	0.54	3.38	49.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	130.1	127.1	(3.0)	-2.3%
		1,500	15.21	2.07	0.77	0.54	3.38	65.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	190.3	183.9	(6.4)	-3.4%
		2,000	15.21	2.07	0.77	0.54	3.38	82.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	250.4	240.6	(9.8)	-3.9%
R1	Rockland	100	9.41	0.92	0.65	0.37	1.94	11.4	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	19.1	29.4	10.4	54.4%
		250	9.41	0.92	0.65	0.37	1.94	14.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	33.5	45.0	11.5	34.2%
		500	9.41	0.92	0.65	0.37	1.94	19.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	57.6	70.9	13.3	23.1%
		750	9.41	0.92	0.65	0.37	1.94	24.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.4	98.8	15.3	18.4%
		1,000	9.41	0.92	0.65	0.37	1.94	28.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.9	127.1	17.2	15.7%
		1,500	9.41	0.92	0.65	0.37	1.94	38.5	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.9	183.9	21.0	12.9%
		2,000	9.41	0.92	0.65	0.37	1.94	48.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	215.8	240.6	24.8	11.5%
R1	Russell	100	13.11	1.44	0.28	0.11	1.83	14.9	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	22.6	29.4	6.8	29.9%
		250	13.11	1.44	0.28	0.11	1.83	17.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	36.9	45.0	8.0	21.7%
		500	13.11	1.44	0.28	0.11	1.83	22.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	60.8	70.9	10.1	16.7%
		750	13.11	1.44	0.28	0.11	1.83	26.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	86.3	98.8	12.4	14.4%
		1,000	13.11	1.44	0.28	0.11	1.83	31.4	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	112.5	127.1	14.6	13.0%
		1,500	13.11	1.44	0.28	0.11	1.83	40.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	164.9	183.9	19.0	11.5%
		2,000	13.11	1.44	0.28	0.11	1.83	49.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	217.3	240.6	23.3	10.7%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Schreiber	100	16.32	1.84	0.68	0.44	2.96	19.3	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	27.0	29.4	2.4	9.0%
		250	16.32	1.84	0.68	0.44	2.96	23.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	43.0	45.0	2.0	4.6%
		500	16.32	1.84	0.68	0.44	2.96	31.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	69.6	70.9	1.3	1.8%
		750	16.32	1.84	0.68	0.44	2.96	38.5	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	98.0	98.8	0.8	0.8%
		1,000	16.32	1.84	0.68	0.44	2.96	45.9	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	127.0	127.1	0.1	0.1%
		1,500	16.32	1.84	0.68	0.44	2.96	60.7	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	185.1	183.9	(1.2)	-0.7%
		2,000	16.32	1.84	0.68	0.44	2.96	75.5	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	243.1	240.6	(2.5)	-1.0%
R1	Severn	100	10.60	0.90	0.59	0.32	1.81	12.4	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	20.1	29.4	9.3	46.2%
		250	10.60	0.90	0.59	0.32	1.81	15.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.4	45.0	10.6	30.8%
		500	10.60	0.90	0.59	0.32	1.81	19.7	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.2	70.9	12.7	21.9%
		750	10.60	0.90	0.59	0.32	1.81	24.2	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.7	98.8	15.1	18.1%
		1,000	10.60	0.90	0.59	0.32	1.81	28.7	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.8	127.1	17.3	15.8%
		1,500	10.60	0.90	0.59	0.32	1.81	37.8	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.1	183.9	21.8	13.4%
		2,000	10.60	0.90	0.59	0.32	1.81	46.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.4	240.6	26.2	12.2%
R1	Shelburne	100	14.14	1.33	0.39	0.14	1.86	16.0	19.04	2.60		(0.04)	2.57	21.6	0.93	0.62	0.70	1.085	2.4	100	-	5.4	23.7	29.4	5.7	24.1%
		250	14.14	1.33	0.39	0.14	1.86	18.8	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.0	45.0	6.9	18.2%
		500	14.14	1.33	0.39	0.14	1.86	23.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.9	70.9	9.0	14.5%
		750	14.14	1.33	0.39	0.14	1.86	28.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	87.6	98.8	11.2	12.8%
		1,000	14.14	1.33	0.39	0.14	1.86	32.7	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	113.8	127.1	13.3	11.7%
		1,500	14.14	1.33	0.39	0.14	1.86	42.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	166.4	183.9	17.5	10.5%
		2,000	14.14	1.33	0.39	0.14	1.86	51.3	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	219.0	240.6	21.7	9.9%
UR	Smiths Falls	100	12.63	1.42	0.46	0.17	2.05	14.7	19.04	2.60		(0.02)	2.58	21.6	0.92	0.62	0.70	1.078	2.4	100	-	5.4	22.4	29.4	7.0	31.2%
		250	12.63	1.42	0.46	0.17	2.05	17.8	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	37.0	44.9	7.9	21.2%
		500	12.63	1.42	0.46	0.17	2.05	22.9	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	61.4	70.7	9.3	15.1%
		750	12.63	1.42	0.46	0.17	2.05	28.0	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	87.5	98.4	10.9	12.5%
		1,000	12.63	1.42	0.46	0.17	2.05	33.1	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	114.2	126.6	12.4	10.8%
		1,500	12.63	1.42	0.46	0.17	2.05	43.4	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	167.7	183.1	15.4	9.2%
		2,000	12.63	1.42	0.46	0.17	2.05	53.6	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.2	239.6	18.4	8.3%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	South Glenç	100	**9.46**	**0.75**	**0.52**	**0.36**	**1.63**	11.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	18.8	29.4	10.6	56.5%
		250	9.46	0.75	0.52	0.36	1.63	13.5	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	32.8	45.0	12.2	37.2%
		500	9.46	0.75	0.52	0.36	1.63	17.6	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.1	70.9	14.8	26.3%
		750	9.46	0.75	0.52	0.36	1.63	21.7	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	81.2	98.8	17.6	21.7%
		1,000	9.46	0.75	0.52	0.36	1.63	25.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	106.9	127.1	20.3	19.0%
		1,500	9.46	0.75	0.52	0.36	1.63	33.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	158.3	183.9	25.6	16.2%
		2,000	9.46	0.75	0.52	0.36	1.63	42.1	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	209.7	240.6	30.9	14.8%
R1	South River	100	**14.22**	**1.25**	**0.63**	**0.41**	**2.29**	16.5	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.2	29.4	5.2	21.5%
		250	14.22	1.25	0.63	0.41	2.29	19.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	39.2	45.0	5.8	14.7%
		500	14.22	1.25	0.63	0.41	2.29	25.7	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.2	70.9	6.7	10.5%
		750	14.22	1.25	0.63	0.41	2.29	31.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.9	98.8	7.9	8.7%
		1,000	14.22	1.25	0.63	0.41	2.29	37.1	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.2	127.1	8.9	7.5%
		1,500	14.22	1.25	0.63	0.41	2.29	48.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	172.9	183.9	10.9	6.3%
		2,000	14.22	1.25	0.63	0.41	2.29	60.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	227.6	240.6	13.0	5.7%
R1	Springwater	100	**11.79**	**0.82**	**0.61**	**0.31**	**1.74**	13.5	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.2	29.4	8.2	38.5%
		250	11.79	0.82	0.61	0.31	1.74	16.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.4	45.0	9.6	27.1%
		500	11.79	0.82	0.61	0.31	1.74	20.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	59.0	70.9	11.9	20.2%
		750	11.79	0.82	0.61	0.31	1.74	24.8	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	84.3	98.8	14.4	17.1%
		1,000	11.79	0.82	0.61	0.31	1.74	29.2	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	110.3	127.1	16.8	15.3%
		1,500	11.79	0.82	0.61	0.31	1.74	37.9	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	162.3	183.9	21.6	13.3%
		2,000	11.79	0.82	0.61	0.31	1.74	46.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	214.2	240.6	26.4	12.3%
R1	Stirling-Raw	100	**12.55**	**1.03**	**0.38**	**0.12**	**1.53**	14.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	21.8	29.4	7.6	35.0%
		250	12.55	1.03	0.38	0.12	1.53	16.4	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	35.6	45.0	9.3	26.2%
		500	12.55	1.03	0.38	0.12	1.53	20.2	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	58.7	70.9	12.2	20.8%
		750	12.55	1.03	0.38	0.12	1.53	24.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	83.5	98.8	15.3	18.3%
		1,000	12.55	1.03	0.38	0.12	1.53	27.9	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	109.0	127.1	18.2	16.7%
		1,500	12.55	1.03	0.38	0.12	1.53	35.5	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	159.9	183.9	24.0	15.0%
		2,000	12.55	1.03	0.38	0.12	1.53	43.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.8	240.6	29.9	14.2%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates						New Dx Rates										New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
								Existing Dx						New Dx	RTSR new	WMSC	DRC	TLF new		5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Thedford	100	**12.75**	**0.81**	**0.82**	**0.52**	**2.15**	14.9	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	22.6	29.4	6.8	30.1%
		250	12.75	0.81	0.82	0.52	2.15	18.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	37.4	45.0	7.6	20.3%
		500	12.75	0.81	0.82	0.52	2.15	23.5	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	62.0	70.9	8.9	14.3%
		750	12.75	0.81	0.82	0.52	2.15	28.9	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	88.4	98.8	10.4	11.8%
		1,000	12.75	0.81	0.82	0.52	2.15	34.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	115.4	127.1	11.8	10.2%
		1,500	12.75	0.81	0.82	0.52	2.15	45.0	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	169.4	183.9	14.5	8.6%
		2,000	12.75	0.81	0.82	0.52	2.15	55.8	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	223.4	240.6	17.3	7.7%
R1	Thessalon	100	**15.56**	**1.05**	**0.28**	**0.12**	**1.45**	17.0	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	24.7	29.4	4.7	19.0%
		250	15.56	1.05	0.28	0.12	1.45	19.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.4	45.0	6.5	17.0%
		500	15.56	1.05	0.28	0.12	1.45	22.8	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	61.3	70.9	9.6	15.6%
		750	15.56	1.05	0.28	0.12	1.45	26.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	85.9	98.8	12.8	14.9%
		1,000	15.56	1.05	0.28	0.12	1.45	30.1	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	111.2	127.1	16.0	14.4%
		1,500	15.56	1.05	0.28	0.12	1.45	37.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	161.7	183.9	22.2	13.7%
		2,000	15.56	1.05	0.28	0.12	1.45	44.6	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	212.2	240.6	28.4	13.4%
R1	Thorndale	100	**4.32**	**0.88**	**0.62**	**0.32**	**1.82**	6.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	13.8	29.4	15.6	112.5%
		250	4.32	0.88	0.62	0.32	1.82	8.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.1	45.0	16.8	59.9%
		500	4.32	0.88	0.62	0.32	1.82	13.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	51.9	70.9	19.0	36.5%
		750	4.32	0.88	0.62	0.32	1.82	18.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	77.5	98.8	21.3	27.5%
		1,000	4.32	0.88	0.62	0.32	1.82	22.5	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	103.6	127.1	23.5	22.7%
		1,500	4.32	0.88	0.62	0.32	1.82	31.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	156.0	183.9	27.9	17.9%
		2,000	4.32	0.88	0.62	0.32	1.82	40.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	208.3	240.6	32.3	15.5%
UR	Thorold	100	**13.68**	**1.47**	**0.41**	**0.14**	**2.02**	15.7	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	23.4	29.4	6.0	25.5%
		250	13.68	1.47	0.41	0.14	2.02	18.7	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	38.0	44.9	6.9	18.1%
		500	13.68	1.47	0.41	0.14	2.02	23.8	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	62.3	70.7	8.4	13.5%
		750	13.68	1.47	0.41	0.14	2.02	28.8	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	88.3	98.4	10.1	11.4%
		1,000	13.68	1.47	0.41	0.14	2.02	33.9	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	115.0	126.6	11.6	10.1%
		1,500	13.68	1.47	0.41	0.14	2.02	44.0	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	168.3	183.1	14.8	8.8%
		2,000	13.68	1.47	0.41	0.14	2.02	54.1	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	221.7	239.6	17.9	8.1%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Tweed	100	**4.48**	**0.95**	**0.61**	**0.37**	**1.93**	6.4	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	14.1	29.4	15.3	108.4%
		250	4.48	0.95	0.61	0.37	1.93	9.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	28.6	45.0	16.4	57.5%
		500	4.48	0.95	0.61	0.37	1.93	14.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	52.6	70.9	18.3	34.7%
		750	4.48	0.95	0.61	0.37	1.93	19.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	78.4	98.8	20.3	25.9%
		1,000	4.48	0.95	0.61	0.37	1.93	23.8	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	104.9	127.1	22.2	21.2%
		1,500	4.48	0.95	0.61	0.37	1.93	33.4	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	157.8	183.9	26.1	16.5%
		2,000	4.48	0.95	0.61	0.37	1.93	43.1	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	210.7	240.6	29.9	14.2%
R1	Wardsville	100	**9.64**	**0.97**	**0.36**	**0.10**	**1.43**	11.1	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	18.8	29.4	10.6	56.7%
		250	9.64	0.97	0.36	0.10	1.43	13.2	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	32.5	45.0	12.5	38.5%
		500	9.64	0.97	0.36	0.10	1.43	16.8	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	55.3	70.9	15.6	28.2%
		750	9.64	0.97	0.36	0.10	1.43	20.4	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	79.8	98.8	18.9	23.7%
		1,000	9.64	0.97	0.36	0.10	1.43	23.9	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.0	127.1	22.1	21.0%
		1,500	9.64	0.97	0.36	0.10	1.43	31.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.5	183.9	28.4	18.3%
		2,000	9.64	0.97	0.36	0.10	1.43	38.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	205.9	240.6	34.8	16.9%
R1	Warkworth	100	**15.25**	**1.18**	**0.66**	**0.43**	**2.27**	17.5	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.2	29.4	4.2	16.6%
		250	15.25	1.18	0.66	0.43	2.27	20.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.2	45.0	4.8	11.9%
		500	15.25	1.18	0.66	0.43	2.27	26.6	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	65.1	70.9	5.8	8.9%
		750	15.25	1.18	0.66	0.43	2.27	32.3	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	91.8	98.8	7.0	7.6%
		1,000	15.25	1.18	0.66	0.43	2.27	38.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	119.1	127.1	8.1	6.8%
		1,500	15.25	1.18	0.66	0.43	2.27	49.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.7	183.9	10.2	5.9%
		2,000	15.25	1.18	0.66	0.43	2.27	60.7	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.3	240.6	12.4	5.4%
R1	West Elgin	100	**13.30**	**1.42**	**0.63**	**0.35**	**2.40**	15.7	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	23.4	29.4	6.0	25.7%
		250	13.30	1.42	0.63	0.35	2.40	19.3	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	38.6	45.0	6.4	16.6%
		500	13.30	1.42	0.63	0.35	2.40	25.3	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	63.8	70.9	7.1	11.1%
		750	13.30	1.42	0.63	0.35	2.40	31.3	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.8	98.8	8.0	8.8%
		1,000	13.30	1.42	0.63	0.35	2.40	37.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	118.4	127.1	8.7	7.4%
		1,500	13.30	1.42	0.63	0.35	2.40	49.3	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	173.7	183.9	10.2	5.9%
		2,000	13.30	1.42	0.63	0.35	2.40	61.3	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	228.9	240.6	11.7	5.1%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
UR	Whitchurch	100	**10.54**	**1.02**	**0.36**	**0.12**	**1.50**	12.0	**19.04**	**2.60**		**(0.02)**	**2.58**	21.6	**0.92**	0.62	0.70	**1.078**	2.4	100	-	5.4	19.7	29.4	9.6	48.8%
		250	10.54	1.02	0.36	0.12	1.50	14.3	19.04	2.60	-	(0.02)	2.58	25.5	0.92	0.62	0.70	1.078	5.9	250	-	13.5	33.5	44.9	11.3	33.7%
		500	10.54	1.02	0.36	0.12	1.50	18.0	19.04	2.60	-	(0.02)	2.58	31.9	0.92	0.62	0.70	1.078	11.8	500	-	27.0	56.5	70.7	14.1	25.0%
		750	10.54	1.02	0.36	0.12	1.50	21.8	19.04	2.60	-	(0.02)	2.58	38.4	0.92	0.62	0.70	1.078	17.7	600	150	42.3	81.3	98.4	17.1	21.0%
		1,000	10.54	1.02	0.36	0.12	1.50	25.5	19.04	2.60	-	(0.02)	2.58	44.8	0.92	0.62	0.70	1.078	23.6	600	400	58.2	106.6	126.6	20.0	18.7%
		1,500	10.54	1.02	0.36	0.12	1.50	33.0	19.04	2.60	-	(0.02)	2.58	57.7	0.92	0.62	0.70	1.078	35.4	600	900	90.0	157.4	183.1	25.7	16.3%
		2,000	10.54	1.02	0.36	0.12	1.50	40.5	19.04	2.60	-	(0.02)	2.58	70.6	0.92	0.62	0.70	1.078	47.2	600	1,400	121.8	208.2	239.6	31.5	15.1%
R1	Wiarton	100	**15.83**	**1.55**	**0.37**	**0.14**	**2.06**	17.9	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	25.6	29.4	3.8	14.9%
		250	15.83	1.55	0.37	0.14	2.06	21.0	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	40.2	45.0	4.7	11.8%
		500	15.83	1.55	0.37	0.14	2.06	26.1	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	64.6	70.9	6.3	9.7%
		750	15.83	1.55	0.37	0.14	2.06	31.3	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	90.8	98.8	8.0	8.8%
		1,000	15.83	1.55	0.37	0.14	2.06	36.4	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	117.5	127.1	9.6	8.2%
		1,500	15.83	1.55	0.37	0.14	2.06	46.7	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	171.1	183.9	12.8	7.5%
		2,000	15.83	1.55	0.37	0.14	2.06	57.0	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	224.6	240.6	16.0	7.1%
R1	Woodville	100	**3.78**	**0.95**	**0.51**	**0.26**	**1.72**	5.5	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	13.2	29.4	16.2	122.8%
		250	3.78	0.95	0.51	0.26	1.72	8.1	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	27.3	45.0	17.6	64.5%
		500	3.78	0.95	0.51	0.26	1.72	12.4	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	50.9	70.9	20.0	39.3%
		750	3.78	0.95	0.51	0.26	1.72	16.7	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	76.2	98.8	22.6	29.7%
		1,000	3.78	0.95	0.51	0.26	1.72	21.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	102.1	127.1	25.0	24.5%
		1,500	3.78	0.95	0.51	0.26	1.72	29.6	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	153.9	183.9	29.9	19.4%
		2,000	3.78	0.95	0.51	0.26	1.72	38.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	205.8	240.6	34.8	16.9%
R1	Wyoming	100	**11.52**	**0.81**	**0.36**	**0.11**	**1.28**	12.8	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	20.5	29.4	8.9	43.5%
		250	11.52	0.81	0.36	0.11	1.28	14.7	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	34.0	45.0	11.0	32.4%
		500	11.52	0.81	0.36	0.11	1.28	17.9	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	56.4	70.9	14.5	25.7%
		750	11.52	0.81	0.36	0.11	1.28	21.1	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	80.6	98.8	18.2	22.5%
		1,000	11.52	0.81	0.36	0.11	1.28	24.3	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	105.4	127.1	21.7	20.6%
		1,500	11.52	0.81	0.36	0.11	1.28	30.7	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	155.1	183.9	28.8	18.6%
		2,000	11.52	0.81	0.36	0.11	1.28	37.1	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	204.7	240.6	35.9	17.5%

New Rate Class: R1

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

600.0

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
R1	Terrace Bay	100	**20.81**	**1.45**	**0.97**	**-**	**2.42**	23.2	**19.04**	**2.60**		**(0.04)**	**2.57**	21.6	**0.93**	0.62	0.70	**1.085**	2.4	100	-	5.4	30.3	29.4	(0.9)	-3.0%
		250	20.81	1.45	0.97	-	2.42	26.9	19.04	2.60	-	(0.04)	2.57	25.5	0.93	0.62	0.70	1.085	6.0	250	-	13.6	44.6	45.0	0.4	0.9%
		500	20.81	1.45	0.97	-	2.42	32.9	19.04	2.60	-	(0.04)	2.57	31.9	0.93	0.62	0.70	1.085	11.9	500	-	27.1	68.4	70.9	2.5	3.7%
		750	20.81	1.45	0.97	-	2.42	39.0	19.04	2.60	-	(0.04)	2.57	38.3	0.93	0.62	0.70	1.085	17.9	600	150	42.6	93.8	98.8	5.0	5.3%
		1,000	20.81	1.45	0.97	-	2.42	45.0	19.04	2.60	-	(0.04)	2.57	44.7	0.93	0.62	0.70	1.085	23.8	600	400	58.6	119.9	127.1	7.2	6.0%
		1,500	20.81	1.45	0.97	-	2.42	57.1	19.04	2.60	-	(0.04)	2.57	57.5	0.93	0.62	0.70	1.085	35.7	600	900	90.6	172.2	183.9	11.7	6.8%
		2,000	20.81	1.45	0.97	-	2.42	69.2	19.04	2.60	-	(0.04)	2.57	70.4	0.93	0.62	0.70	1.085	47.6	600	1,400	122.6	224.4	240.6	16.2	7.2%

New Rate Class: R2

Total Bill Impacts of Target Distribution Rates [new RTSR+TLF]: Threshold of 600 kWhs

Classes		Scenario	May 2007 Incl Rate Riders						Target Incl Rate Riders						Non-Dx Compoent				Other Reg	Commodity Bands			Existing	New	$ Incr	% Incr
			Existing Dx Rates					Existing Dx	New Dx Rates					New Dx	RTSR new	WMSC	DRC	TLF new	New	Band 1	Band 2	New	Total Bill	Total Bill	Total Bill	Total Bill
																				5.0	5.9					
New Class	Old Class	kWh	SrChg	base	Rider1	Rider2	VarChg	[$/month]	SrChg	base	Rider2	Rider3	VarChg	[$/month]	c/kWh	c/kWh	c/kWh		$	kWhs	kWhs		[$/month]	[$/month]	[$/month]	%
			[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]													
R2	R2	100	**29.22**	**1.94**	**0.12**	**0.13**	**2.19**	31.4	**21.41**	**3.10**		**(0.05)**	**3.05**	24.5	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	39.3	32.3	(7.0)	-17.9%
		250	29.22	1.94	0.12	0.13	2.19	34.7	21.41	3.10	-	(0.05)	3.05	29.0	0.89	0.62	0.7	1.09	5.9	250	-	13.7	54.4	48.5	(5.8)	-10.7%
		500	29.22	1.94	0.12	0.13	2.19	40.2	21.41	3.10	-	(0.05)	3.05	36.6	0.89	0.62	0.7	1.09	11.7	500	-	27.3	79.5	75.7	(3.8)	-4.8%
		750	29.22	1.94	0.12	0.13	2.19	45.6	21.41	3.10	-	(0.05)	3.05	44.3	0.89	0.62	0.7	1.09	17.6	600	150	42.9	106.6	104.8	(1.8)	-1.7%
		1,000	29.22	1.94	0.12	0.13	2.19	51.1	21.41	3.10	-	(0.05)	3.05	51.9	0.89	0.62	0.7	1.09	23.5	600	400	59.0	134.2	134.4	0.2	0.2%
		1,500	29.22	1.94	0.12	0.13	2.19	62.1	21.41	3.10	-	(0.05)	3.05	67.1	0.89	0.62	0.7	1.09	35.2	600	900	91.2	189.4	193.6	4.2	2.2%
		2,000	29.22	1.94	0.12	0.13	2.19	73.0	21.41	3.10	-	(0.05)	3.05	82.3	0.89	0.62	0.7	1.09	47.0	600	1,400	123.5	244.5	252.8	8.2	3.4%
R2	F1	100	**28.61**	**2.24**	**0.08**	**0.10**	**2.42**	31.0	**21.41**	**3.10**		**(0.05)**	**3.05**	24.5	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	38.8	32.3	(6.6)	-16.9%
		250	28.61	2.24	0.08	0.10	2.42	34.7	21.41	3.10	-	(0.05)	3.05	29.0	0.89	0.62	0.70	1.09	5.9	250	-	13.7	54.2	48.5	(5.6)	-10.4%
		500	28.61	2.24	0.08	0.10	2.42	40.7	21.41	3.10	-	(0.05)	3.05	36.6	0.89	0.62	0.70	1.09	11.7	500	-	27.3	79.8	75.7	(4.1)	-5.1%
		750	28.61	2.24	0.08	0.10	2.42	46.8	21.41	3.10	-	(0.05)	3.05	44.3	0.89	0.62	0.70	1.09	17.6	600	150	42.9	107.3	104.8	(2.5)	-2.3%
		1,000	28.61	2.24	0.08	0.10	2.42	52.8	21.41	3.10	-	(0.05)	3.05	51.9	0.89	0.62	0.70	1.09	23.5	600	400	59.0	135.3	134.4	(0.9)	-0.7%
		1,500	28.61	2.24	0.08	0.10	2.42	64.9	21.41	3.10	-	(0.05)	3.05	67.1	0.89	0.62	0.70	1.09	35.2	600	900	91.2	191.4	193.6	2.2	1.1%
		2,000	28.61	2.24	0.08	0.10	2.42	77.0	21.41	3.10	-	(0.05)	3.05	82.3	0.89	0.62	0.70	1.09	47.0	600	1,400	123.5	247.4	252.8	5.3	2.2%
R2	F3	100	**30.16**	**2.89**	**0.03**	**0.04**	**2.96**	33.1	**21.41**	**3.10**		**(0.05)**	**3.05**	24.5	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	40.7	32.3	(8.4)	-20.7%
		250	30.16	2.89	0.03	0.04	2.96	37.6	21.41	3.10	-	(0.05)	3.05	29.0	0.89	0.62	0.70	1.09	5.9	250	-	13.7	56.4	48.5	(7.9)	-14.0%
		500	30.16	2.89	0.03	0.04	2.96	45.0	21.41	3.10	-	(0.05)	3.05	36.6	0.89	0.62	0.70	1.09	11.7	500	-	27.3	82.7	75.7	(7.0)	-8.5%
		750	30.16	2.89	0.03	0.04	2.96	52.4	21.41	3.10	-	(0.05)	3.05	44.3	0.89	0.62	0.70	1.09	17.6	600	150	42.9	110.8	104.8	(6.0)	-5.4%
		1,000	30.16	2.89	0.03	0.04	2.96	59.8	21.41	3.10	-	(0.05)	3.05	51.9	0.89	0.62	0.70	1.09	23.5	600	400	59.0	139.4	134.4	(5.1)	-3.6%
		1,500	30.16	2.89	0.03	0.04	2.96	74.6	21.41	3.10	-	(0.05)	3.05	67.1	0.89	0.62	0.70	1.09	35.2	600	900	91.2	196.8	193.6	(3.2)	-1.6%
		2,000	30.16	2.89	0.03	0.04	2.96	89.4	21.41	3.10	-	(0.05)	3.05	82.3	0.89	0.62	0.70	1.09	47.0	600	1,400	123.5	254.1	252.8	(1.4)	-0.5%
R2	Caledon OH 06	100	**34.85**	**0.50**	**0.25**	**0.11**	**0.86**	35.7	**21.41**	**3.10**		**(0.05)**	**3.05**	24.5	**0.89**	0.62	0.7	**1.092**	2.3	100	-	5.5	43.4	32.3	(11.2)	-25.7%
		250	34.85	0.50	0.25	0.11	0.86	37.0	21.41	3.10	-	(0.05)	3.05	29.0	0.89	0.62	0.70	1.09	5.9	250	-	13.7	56.3	48.5	(7.7)	-13.7%
		500	34.85	0.50	0.25	0.11	0.86	39.2	21.41	3.10	-	(0.05)	3.05	36.6	0.89	0.62	0.70	1.09	11.7	500	-	27.3	77.7	75.7	(2.0)	-2.5%
		750	34.85	0.50	0.25	0.11	0.86	41.3	21.41	3.10	-	(0.05)	3.05	44.3	0.89	0.62	0.70	1.09	17.6	600	150	42.9	100.8	104.8	4.0	4.0%
		1,000	34.85	0.50	0.25	0.11	0.86	43.5	21.41	3.10	-	(0.05)	3.05	51.9	0.89	0.62	0.70	1.09	23.5	600	400	59.0	124.6	134.4	9.8	7.9%
		1,500	34.85	0.50	0.25	0.11	0.86	47.8	21.41	3.10	-	(0.05)	3.05	67.1	0.89	0.62	0.70	1.09	35.2	600	900	91.2	172.1	193.6	21.5	12.5%
		2,000	34.85	0.50	0.25	0.11	0.86	52.1	21.41	3.10	-	(0.05)	3.05	82.3	0.89	0.62	0.70	1.09	47.0	600	1,400	123.5	219.7	252.8	33.1	15.1%

New Rate Class: UR

Bill Impacts of Target Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
UR	UR	100	14.32	1.83	16.15	14.32	2.29	16.61	0.46	2.9%
		250	14.32	1.83	18.90	14.32	2.29	20.06	1.16	6.1%
		500	14.32	1.83	23.47	14.32	2.29	25.79	2.32	9.9%
		750	14.32	1.83	28.05	14.32	2.29	31.53	3.48	12.4%
		1,000	14.32	1.83	32.62	14.32	2.29	37.26	4.64	14.2%
		1,500	14.32	1.83	41.77	14.32	2.29	48.74	6.97	16.7%
		2,000	14.32	1.83	50.92	14.32	2.29	60.21	9.29	18.2%
UR	R1	100	19.04	2.38	21.42	14.32	2.29	16.61	(4.81)	-22.4%
		250	19.04	2.38	24.99	14.32	2.29	20.06	(4.93)	-19.7%
		500	19.04	2.38	30.94	14.32	2.29	25.79	(5.15)	-16.6%
		750	19.04	2.38	36.89	14.32	2.29	31.53	(5.36)	-14.5%
		1,000	19.04	2.38	42.84	14.32	2.29	37.26	(5.58)	-13.0%
		1,500	19.04	2.38	54.74	14.32	2.29	48.74	(6.00)	-11.0%
		2,000	19.04	2.38	66.64	14.32	2.29	60.21	(6.43)	-9.7%
UR	R2	100	29.22	1.94	31.16	14.32	2.29	16.61	(14.55)	-46.7%
		250	29.22	1.94	34.07	14.32	2.29	20.06	(14.01)	-41.1%
		500	29.22	1.94	38.92	14.32	2.29	25.79	(13.13)	-33.7%
		750	29.22	1.94	43.77	14.32	2.29	31.53	(12.24)	-28.0%
		1,000	29.22	1.94	48.62	14.32	2.29	37.26	(11.36)	-23.4%
		1,500	29.22	1.94	58.32	14.32	2.29	48.74	(9.58)	-16.4%
		2,000	29.22	1.94	68.02	14.32	2.29	60.21	(7.81)	-11.5%
UR	F1	100	28.61	2.24	30.85	14.32	2.29	16.61	(14.24)	-46.1%
		250	28.61	2.24	34.21	14.32	2.29	20.06	(14.15)	-41.4%
		500	28.61	2.24	39.81	14.32	2.29	25.79	(14.02)	-35.2%
		750	28.61	2.24	45.41	14.32	2.29	31.53	(13.88)	-30.6%
		1,000	28.61	2.24	51.01	14.32	2.29	37.26	(13.75)	-26.9%
		1,500	28.61	2.24	62.21	14.32	2.29	48.74	(13.47)	-21.7%
		2,000	28.61	2.24	73.41	14.32	2.29	60.21	(13.20)	-18.0%

New Rate Class: UR

Bill Impacts of Target Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
UR	Arnprior	100	11.54	1.47	13.01	14.32	2.29	16.61	3.60	27.7%
		250	11.54	1.47	15.22	14.32	2.29	20.06	4.84	31.8%
		500	11.54	1.47	18.89	14.32	2.29	25.79	6.90	36.5%
		750	11.54	1.47	22.57	14.32	2.29	31.53	8.96	39.7%
		1,000	11.54	1.47	26.24	14.32	2.29	37.26	11.02	42.0%
		1,500	11.54	1.47	33.59	14.32	2.29	48.74	15.15	45.1%
		2,000	11.54	1.47	40.94	14.32	2.29	60.21	19.27	47.1%
UR	Brockville	100	12.33	0.93	13.26	14.32	2.29	16.61	3.35	25.3%
		250	12.33	0.93	14.66	14.32	2.29	20.06	5.40	36.9%
		500	12.33	0.93	16.98	14.32	2.29	25.79	8.81	51.9%
		750	12.33	0.93	19.31	14.32	2.29	31.53	12.22	63.3%
		1,000	12.33	0.93	21.63	14.32	2.29	37.26	15.63	72.3%
		1,500	12.33	0.93	26.28	14.32	2.29	48.74	22.46	85.5%
		2,000	12.33	0.93	30.93	14.32	2.29	60.21	29.28	94.7%
UR	Caledon OH 01	100	18.52	0.57	19.09	14.32	2.29	16.61	(2.48)	-13.0%
		250	18.52	0.57	19.95	14.32	2.29	20.06	0.11	0.6%
		500	18.52	0.57	21.37	14.32	2.29	25.79	4.42	20.7%
		750	18.52	0.57	22.80	14.32	2.29	31.53	8.73	38.3%
		1,000	18.52	0.57	24.22	14.32	2.29	37.26	13.04	53.9%
		1,500	18.52	0.57	27.07	14.32	2.29	48.74	21.67	80.0%
		2,000	18.52	0.57	29.92	14.32	2.29	60.21	30.29	101.2%
UR	Carleton Place	100	14.17	1.79	15.96	14.32	2.29	16.61	0.65	4.1%
		250	14.17	1.79	18.65	14.32	2.29	20.06	1.41	7.6%
		500	14.17	1.79	23.12	14.32	2.29	25.79	2.67	11.6%
		750	14.17	1.79	27.60	14.32	2.29	31.53	3.93	14.3%
		1,000	14.17	1.79	32.07	14.32	2.29	37.26	5.19	16.2%
		1,500	14.17	1.79	41.02	14.32	2.29	48.74	7.72	18.8%
		2,000	14.17	1.79	49.97	14.32	2.29	60.21	10.24	20.5%

New Rate Class: UR

Bill Impacts of Target Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
UR	Dryden	100	14.28	1.65	15.93	14.32	2.29	16.61	0.68	4.3%
		250	14.28	1.65	18.41	14.32	2.29	20.06	1.65	9.0%
		500	14.28	1.65	22.53	14.32	2.29	25.79	3.26	14.5%
		750	14.28	1.65	26.66	14.32	2.29	31.53	4.87	18.3%
		1,000	14.28	1.65	30.78	14.32	2.29	37.26	6.48	21.1%
		1,500	14.28	1.65	39.03	14.32	2.29	48.74	9.71	24.9%
		2,000	14.28	1.65	47.28	14.32	2.29	60.21	12.93	27.3%
UR	GBE	100	9.68	0.95	10.63	14.32	2.29	16.61	5.98	56.3%
		250	9.68	0.95	12.06	14.32	2.29	20.06	8.00	66.4%
		500	9.68	0.95	14.43	14.32	2.29	25.79	11.36	78.7%
		750	9.68	0.95	16.81	14.32	2.29	31.53	14.72	87.6%
		1,000	9.68	0.95	19.18	14.32	2.29	37.26	18.08	94.3%
		1,500	9.68	0.95	23.93	14.32	2.29	48.74	24.81	103.7%
		2,000	9.68	0.95	28.68	14.32	2.29	60.21	31.53	109.9%
UR	Lindsay	100	15.81	1.01	16.82	14.32	2.29	16.61	(0.21)	-1.2%
		250	15.81	1.01	18.34	14.32	2.29	20.06	1.72	9.4%
		500	15.81	1.01	20.86	14.32	2.29	25.79	4.93	23.6%
		750	15.81	1.01	23.39	14.32	2.29	31.53	8.14	34.8%
		1,000	15.81	1.01	25.91	14.32	2.29	37.26	11.35	43.8%
		1,500	15.81	1.01	30.96	14.32	2.29	48.74	17.78	57.4%
		2,000	15.81	1.01	36.01	14.32	2.29	60.21	24.20	67.2%
UR	Perth	100	14.47	1.22	15.69	14.32	2.29	16.61	0.92	5.9%
		250	14.47	1.22	17.52	14.32	2.29	20.06	2.54	14.5%
		500	14.47	1.22	20.57	14.32	2.29	25.79	5.22	25.4%
		750	14.47	1.22	23.62	14.32	2.29	31.53	7.91	33.5%
		1,000	14.47	1.22	26.67	14.32	2.29	37.26	10.59	39.7%
		1,500	14.47	1.22	32.77	14.32	2.29	48.74	15.97	48.7%
		2,000	14.47	1.22	38.87	14.32	2.29	60.21	21.34	54.9%

New Rate Class: UR

Bill Impacts of Target Distribution Rates exclude Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
UR	Quinte West	100	6.58	0.92	7.50	14.32	2.29	16.61	9.11	121.5%
		250	6.58	0.92	8.88	14.32	2.29	20.06	11.18	125.9%
		500	6.58	0.92	11.18	14.32	2.29	25.79	14.61	130.7%
		750	6.58	0.92	13.48	14.32	2.29	31.53	18.05	133.9%
		1,000	6.58	0.92	15.78	14.32	2.29	37.26	21.48	136.1%
		1,500	6.58	0.92	20.38	14.32	2.29	48.74	28.36	139.1%
		2,000	6.58	0.92	24.98	14.32	2.29	60.21	35.23	141.0%
UR	Smiths Falls	100	12.63	1.42	14.05	14.32	2.29	16.61	2.56	18.3%
		250	12.63	1.42	16.18	14.32	2.29	20.06	3.88	24.0%
		500	12.63	1.42	19.73	14.32	2.29	25.79	6.06	30.7%
		750	12.63	1.42	23.28	14.32	2.29	31.53	8.25	35.4%
		1,000	12.63	1.42	26.83	14.32	2.29	37.26	10.43	38.9%
		1,500	12.63	1.42	33.93	14.32	2.29	48.74	14.81	43.6%
		2,000	12.63	1.42	41.03	14.32	2.29	60.21	19.18	46.7%
UR	Thorold	100	13.68	1.47	15.15	14.32	2.29	16.61	1.46	9.7%
		250	13.68	1.47	17.36	14.32	2.29	20.06	2.70	15.6%
		500	13.68	1.47	21.03	14.32	2.29	25.79	4.76	22.6%
		750	13.68	1.47	24.71	14.32	2.29	31.53	6.82	27.6%
		1,000	13.68	1.47	28.38	14.32	2.29	37.26	8.88	31.3%
		1,500	13.68	1.47	35.73	14.32	2.29	48.74	13.01	36.4%
		2,000	13.68	1.47	43.08	14.32	2.29	60.21	17.13	39.8%
UR	Whitchurch Stouffville	100	10.54	1.02	11.56	14.32	2.29	16.61	5.05	43.7%
		250	10.54	1.02	13.09	14.32	2.29	20.06	6.97	53.2%
		500	10.54	1.02	15.64	14.32	2.29	25.79	10.15	64.9%
		750	10.54	1.02	18.19	14.32	2.29	31.53	13.34	73.3%
		1,000	10.54	1.02	20.74	14.32	2.29	37.26	16.52	79.7%
		1,500	10.54	1.02	25.84	14.32	2.29	48.74	22.90	88.6%
		2,000	10.54	1.02	30.94	14.32	2.29	60.21	29.27	94.6%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	R1	100	19.04	2.38	21.42	19.04	2.60	21.64	0.22	1.0%
		250	19.04	2.38	24.99	19.04	2.60	25.55	0.56	2.2%
		500	19.04	2.38	30.94	19.04	2.60	32.06	1.12	3.6%
		750	19.04	2.38	36.89	19.04	2.60	38.56	1.67	4.5%
		1,000	19.04	2.38	42.84	19.04	2.60	45.07	2.23	5.2%
		1,500	19.04	2.38	54.74	19.04	2.60	58.09	3.35	6.1%
		2,000	19.04	2.38	66.64	19.04	2.60	71.10	4.46	6.7%
R1	Ailsa Craig	100	10.51	0.82	11.33	19.04	2.60	21.64	10.31	91.0%
		250	10.51	0.82	12.56	19.04	2.60	25.55	12.99	103.4%
		500	10.51	0.82	14.61	19.04	2.60	32.06	17.45	119.4%
		750	10.51	0.82	16.66	19.04	2.60	38.56	21.90	131.5%
		1,000	10.51	0.82	18.71	19.04	2.60	45.07	26.36	140.9%
		1,500	10.51	0.82	22.81	19.04	2.60	58.09	35.28	154.7%
		2,000	10.51	0.82	26.91	19.04	2.60	71.10	44.19	164.2%
R1	Arkona	100	5.84	0.26	6.10	19.04	2.60	21.64	15.54	254.8%
		250	5.84	0.26	6.49	19.04	2.60	25.55	19.06	293.7%
		500	5.84	0.26	7.14	19.04	2.60	32.06	24.92	349.0%
		750	5.84	0.26	7.79	19.04	2.60	38.56	30.77	395.0%
		1,000	5.84	0.26	8.44	19.04	2.60	45.07	36.63	434.0%
		1,500	5.84	0.26	9.74	19.04	2.60	58.09	48.35	496.4%
		2,000	5.84	0.26	11.04	19.04	2.60	71.10	60.06	544.1%
UR	Arnprior	100	11.54	1.47	13.01	19.04	2.60	21.64	8.63	66.4%
		250	11.54	1.47	15.22	19.04	2.60	25.55	10.33	67.9%
		500	11.54	1.47	18.89	19.04	2.60	32.06	13.17	69.7%
		750	11.54	1.47	22.57	19.04	2.60	38.56	16.00	70.9%
		1,000	11.54	1.47	26.24	19.04	2.60	45.07	18.83	71.8%
		1,500	11.54	1.47	33.59	19.04	2.60	58.09	24.50	72.9%
		2,000	11.54	1.47	40.94	19.04	2.60	71.10	30.16	73.7%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	Arran-Elderslie	100	9.02	0.95	9.97	19.04	2.60	21.64	11.67	117.1%
		250	9.02	0.95	11.40	19.04	2.60	25.55	14.15	124.2%
		500	9.02	0.95	13.77	19.04	2.60	32.06	18.29	132.8%
		750	9.02	0.95	16.15	19.04	2.60	38.56	22.42	138.9%
		1,000	9.02	0.95	18.52	19.04	2.60	45.07	26.55	143.4%
		1,500	9.02	0.95	23.27	19.04	2.60	58.09	34.82	149.6%
		2,000	9.02	0.95	28.02	19.04	2.60	71.10	43.08	153.8%
R1	Artemesia	100	12.73	0.93	13.66	19.04	2.60	21.64	7.98	58.4%
		250	12.73	0.93	15.06	19.04	2.60	25.55	10.49	69.7%
		500	12.73	0.93	17.38	19.04	2.60	32.06	14.68	84.4%
		750	12.73	0.93	19.71	19.04	2.60	38.56	18.86	95.7%
		1,000	12.73	0.93	22.03	19.04	2.60	45.07	23.04	104.6%
		1,500	12.73	0.93	26.68	19.04	2.60	58.09	31.41	117.7%
		2,000	12.73	0.93	31.33	19.04	2.60	71.10	39.77	127.0%
R1	Bancroft	100	13.48	0.95	14.43	19.04	2.60	21.64	7.21	50.0%
		250	13.48	0.95	15.86	19.04	2.60	25.55	9.69	61.1%
		500	13.48	0.95	18.23	19.04	2.60	32.06	13.83	75.8%
		750	13.48	0.95	20.61	19.04	2.60	38.56	17.96	87.2%
		1,000	13.48	0.95	22.98	19.04	2.60	45.07	22.09	96.1%
		1,500	13.48	0.95	27.73	19.04	2.60	58.09	30.36	109.5%
		2,000	13.48	0.95	32.48	19.04	2.60	71.10	38.62	118.9%
R1	Bath	100	13.38	0.86	14.24	19.04	2.60	21.64	7.40	52.0%
		250	13.38	0.86	15.53	19.04	2.60	25.55	10.02	64.5%
		500	13.38	0.86	17.68	19.04	2.60	32.06	14.38	81.3%
		750	13.38	0.86	19.83	19.04	2.60	38.56	18.73	94.5%
		1,000	13.38	0.86	21.98	19.04	2.60	45.07	23.09	105.1%
		1,500	13.38	0.86	26.28	19.04	2.60	58.09	31.81	121.0%
		2,000	13.38	0.86	30.58	19.04	2.60	71.10	40.52	132.5%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	Blandford-Blenheim	100	11.63	0.90	12.53	19.04	2.60	21.64	9.11	72.7%
		250	11.63	0.90	13.88	19.04	2.60	25.55	11.67	84.1%
		500	11.63	0.90	16.13	19.04	2.60	32.06	15.93	98.7%
		750	11.63	0.90	18.38	19.04	2.60	38.56	20.18	109.8%
		1,000	11.63	0.90	20.63	19.04	2.60	45.07	24.44	118.5%
		1,500	11.63	0.90	25.13	19.04	2.60	58.09	32.96	131.1%
		2,000	11.63	0.90	29.63	19.04	2.60	71.10	41.47	140.0%
R1	Blyth	100	7.19	0.91	8.10	19.04	2.60	21.64	13.54	167.2%
		250	7.19	0.91	9.47	19.04	2.60	25.55	16.08	169.9%
		500	7.19	0.91	11.74	19.04	2.60	32.06	20.32	173.0%
		750	7.19	0.91	14.02	19.04	2.60	38.56	24.55	175.2%
		1,000	7.19	0.91	16.29	19.04	2.60	45.07	28.78	176.7%
		1,500	7.19	0.91	20.84	19.04	2.60	58.09	37.25	178.7%
		2,000	7.19	0.91	25.39	19.04	2.60	71.10	45.71	180.0%
R1	Bobcaygeon	100	14.47	0.97	15.44	19.04	2.60	21.64	6.20	40.2%
		250	14.47	0.97	16.90	19.04	2.60	25.55	8.65	51.2%
		500	14.47	0.97	19.32	19.04	2.60	32.06	12.74	65.9%
		750	14.47	0.97	21.75	19.04	2.60	38.56	16.82	77.3%
		1,000	14.47	0.97	24.17	19.04	2.60	45.07	20.90	86.5%
		1,500	14.47	0.97	29.02	19.04	2.60	58.09	29.07	100.2%
		2,000	14.47	0.97	33.87	19.04	2.60	71.10	37.23	109.9%
R1	Brighton	100	11.61	1.07	12.68	19.04	2.60	21.64	8.96	70.7%
		250	11.61	1.07	14.29	19.04	2.60	25.55	11.26	78.8%
		500	11.61	1.07	16.96	19.04	2.60	32.06	15.10	89.0%
		750	11.61	1.07	19.64	19.04	2.60	38.56	18.93	96.4%
		1,000	11.61	1.07	22.31	19.04	2.60	45.07	22.76	102.0%
		1,500	11.61	1.07	27.66	19.04	2.60	58.09	30.43	110.0%
		2,000	11.61	1.07	33.01	19.04	2.60	71.10	38.09	115.4%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
UR	Brockville	100	12.33	0.93	13.26	19.04	2.60	21.64	8.38	63.2%
		250	12.33	0.93	14.66	19.04	2.60	25.55	10.89	74.3%
		500	12.33	0.93	16.98	19.04	2.60	32.06	15.08	88.8%
		750	12.33	0.93	19.31	19.04	2.60	38.56	19.26	99.8%
		1,000	12.33	0.93	21.63	19.04	2.60	45.07	23.44	108.4%
		1,500	12.33	0.93	26.28	19.04	2.60	58.09	31.81	121.0%
		2,000	12.33	0.93	30.93	19.04	2.60	71.10	40.17	129.9%
R1	Caledon CH 02	100	15.19	1.02	16.21	19.04	2.60	21.64	5.43	33.5%
		250	15.19	1.02	17.74	19.04	2.60	25.55	7.81	44.0%
		500	15.19	1.02	20.29	19.04	2.60	32.06	11.77	58.0%
		750	15.19	1.02	22.84	19.04	2.60	38.56	15.72	68.8%
		1,000	15.19	1.02	25.39	19.04	2.60	45.07	19.68	77.5%
		1,500	15.19	1.02	30.49	19.04	2.60	58.09	27.60	90.5%
		2,000	15.19	1.02	35.59	19.04	2.60	71.10	35.51	99.8%
R1	Campbellford-Seymour	100	12.30	1.07	13.37	19.04	2.60	21.64	8.27	61.9%
		250	12.30	1.07	14.98	19.04	2.60	25.55	10.57	70.6%
		500	12.30	1.07	17.65	19.04	2.60	32.06	14.41	81.6%
		750	12.30	1.07	20.33	19.04	2.60	38.56	18.24	89.7%
		1,000	12.30	1.07	23.00	19.04	2.60	45.07	22.07	96.0%
		1,500	12.30	1.07	28.35	19.04	2.60	58.09	29.74	104.9%
		2,000	12.30	1.07	33.70	19.04	2.60	71.10	37.40	111.0%
UR	Carleton Place	100	14.17	1.79	15.96	19.04	2.60	21.64	5.68	35.6%
		250	14.17	1.79	18.65	19.04	2.60	25.55	6.90	37.0%
		500	14.17	1.79	23.12	19.04	2.60	32.06	8.94	38.7%
		750	14.17	1.79	27.60	19.04	2.60	38.56	10.97	39.7%
		1,000	14.17	1.79	32.07	19.04	2.60	45.07	13.00	40.5%
		1,500	14.17	1.79	41.02	19.04	2.60	58.09	17.07	41.6%
		2,000	14.17	1.79	49.97	19.04	2.60	71.10	21.13	42.3%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Cavan-Millbrook-North Monaghan**	100	15.01	1.34	16.35	19.04	2.60	21.64	5.29	32.4%
		250	15.01	1.34	18.36	19.04	2.60	25.55	7.19	39.2%
		500	15.01	1.34	21.71	19.04	2.60	32.06	10.35	47.7%
		750	15.01	1.34	25.06	19.04	2.60	38.56	13.50	53.9%
		1000	15.01	1.34	28.41	19.04	2.60	45.07	16.66	58.6%
		1500	15.01	1.34	35.11	19.04	2.60	58.09	22.98	65.4%
		2000	15.01	1.34	41.81	19.04	2.60	71.10	29.29	70.1%
R1	**Centre Hastings**	100	11.67	0.96	12.63	19.04	2.60	21.64	9.01	71.4%
		250	11.67	0.96	14.07	19.04	2.60	25.55	11.48	81.6%
		500	11.67	0.96	16.47	19.04	2.60	32.06	15.59	94.6%
		750	11.67	0.96	18.87	19.04	2.60	38.56	19.69	104.4%
		1000	11.67	0.96	21.27	19.04	2.60	45.07	23.80	111.9%
		1500	11.67	0.96	26.07	19.04	2.60	58.09	32.02	122.8%
		2000	11.67	0.96	30.87	19.04	2.60	71.10	40.23	130.3%
R1	**Chalk River**	100	14.03	1.37	15.40	19.04	2.60	21.64	6.24	40.5%
		250	14.03	1.37	17.46	19.04	2.60	25.55	8.09	46.4%
		500	14.03	1.37	20.88	19.04	2.60	32.06	11.18	53.5%
		750	14.03	1.37	24.31	19.04	2.60	38.56	14.26	58.7%
		1000	14.03	1.37	27.73	19.04	2.60	45.07	17.34	62.5%
		1500	14.03	1.37	34.58	19.04	2.60	58.09	23.51	68.0%
		2000	14.03	1.37	41.43	19.04	2.60	71.10	29.67	71.6%
R1	**Champlain**	100	10.36	0.88	11.24	19.04	2.60	21.64	10.40	92.6%
		250	10.36	0.88	12.56	19.04	2.60	25.55	12.99	103.4%
		500	10.36	0.88	14.76	19.04	2.60	32.06	17.30	117.2%
		750	10.36	0.88	16.96	19.04	2.60	38.56	21.60	127.4%
		1000	10.36	0.88	19.16	19.04	2.60	45.07	25.91	135.2%
		1500	10.36	0.88	23.56	19.04	2.60	58.09	34.53	146.6%
		2000	10.36	0.88	27.96	19.04	2.60	71.10	43.14	154.3%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Cobden**	100	13.07	1.76	14.83	19.04	2.60	21.64	6.81	45.9%
		250	13.07	1.76	17.47	19.04	2.60	25.55	8.08	46.2%
		500	13.07	1.76	21.87	19.04	2.60	32.06	10.19	46.6%
		750	13.07	1.76	26.27	19.04	2.60	38.56	12.29	46.8%
		1000	13.07	1.76	30.67	19.04	2.60	45.07	14.40	47.0%
		1500	13.07	1.76	39.47	19.04	2.60	58.09	18.62	47.2%
		2000	13.07	1.76	48.27	19.04	2.60	71.10	22.83	47.3%
R1	**Deep River**	100	16.62	2.29	18.91	19.04	2.60	21.64	2.73	14.5%
		250	16.62	2.29	22.35	19.04	2.60	25.55	3.20	14.3%
		500	16.62	2.29	28.07	19.04	2.60	32.06	3.99	14.2%
		750	16.62	2.29	33.80	19.04	2.60	38.56	4.77	14.1%
		1000	16.62	2.29	39.52	19.04	2.60	45.07	5.55	14.0%
		1500	16.62	2.29	50.97	19.04	2.60	58.09	7.12	14.0%
		2000	16.62	2.29	62.42	19.04	2.60	71.10	8.68	13.9%
R1	**Deseronto**	100	12.89	1.12	14.01	19.04	2.60	21.64	7.63	54.5%
		250	12.89	1.12	15.69	19.04	2.60	25.55	9.86	62.8%
		500	12.89	1.12	18.49	19.04	2.60	32.06	13.57	73.4%
		750	12.89	1.12	21.29	19.04	2.60	38.56	17.27	81.1%
		1000	12.89	1.12	24.09	19.04	2.60	45.07	20.98	87.1%
		1500	12.89	1.12	29.69	19.04	2.60	58.09	28.40	95.6%
		2000	12.89	1.12	35.29	19.04	2.60	71.10	35.81	101.5%
UR	**Dryden**	100	14.28	1.65	15.93	19.04	2.60	21.64	5.71	35.9%
		250	14.28	1.65	18.41	19.04	2.60	25.55	7.14	38.8%
		500	14.28	1.65	22.53	19.04	2.60	32.06	9.53	42.3%
		750	14.28	1.65	26.66	19.04	2.60	38.56	11.91	44.7%
		1000	14.28	1.65	30.78	19.04	2.60	45.07	14.29	46.4%
		1500	14.28	1.65	39.03	19.04	2.60	58.09	19.06	48.8%
		2000	14.28	1.65	47.28	19.04	2.60	71.10	23.82	50.4%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Dundalk**	100	14.47	1.08	15.55	19.04	2.60	21.64	6.09	39.2%
		250	14.47	1.08	17.17	19.04	2.60	25.55	8.38	48.8%
		500	14.47	1.08	19.87	19.04	2.60	32.06	12.19	61.3%
		750	14.47	1.08	22.57	19.04	2.60	38.56	15.99	70.9%
		1000	14.47	1.08	25.27	19.04	2.60	45.07	19.80	78.4%
		1500	14.47	1.08	30.67	19.04	2.60	58.09	27.42	89.4%
		2000	14.47	1.08	36.07	19.04	2.60	71.10	35.03	97.1%
R1	**Durham**	100	16.35	1.24	17.59	19.04	2.60	21.64	4.05	23.0%
		250	16.35	1.24	19.45	19.04	2.60	25.55	6.10	31.4%
		500	16.35	1.24	22.55	19.04	2.60	32.06	9.51	42.2%
		750	16.35	1.24	25.65	19.04	2.60	38.56	12.91	50.3%
		1000	16.35	1.24	28.75	19.04	2.60	45.07	16.32	56.8%
		1500	16.35	1.24	34.95	19.04	2.60	58.09	23.14	66.2%
		2000	16.35	1.24	41.15	19.04	2.60	71.10	29.95	72.8%
R1	**Eganville**	100	13.86	1.53	15.39	19.04	2.60	21.64	6.25	40.6%
		250	13.86	1.53	17.69	19.04	2.60	25.55	7.86	44.5%
		500	13.86	1.53	21.51	19.04	2.60	32.06	10.55	49.0%
		750	13.86	1.53	25.34	19.04	2.60	38.56	13.23	52.2%
		1000	13.86	1.53	29.16	19.04	2.60	45.07	15.91	54.6%
		1500	13.86	1.53	36.81	19.04	2.60	58.09	21.28	57.8%
		2000	13.86	1.53	44.46	19.04	2.60	71.10	26.64	59.9%
R1	**Erin**	100	13.13	1.90	15.03	19.04	2.60	21.64	6.61	44.0%
		250	13.13	1.90	17.88	19.04	2.60	25.55	7.67	42.9%
		500	13.13	1.90	22.63	19.04	2.60	32.06	9.43	41.7%
		750	13.13	1.90	27.38	19.04	2.60	38.56	11.18	40.8%
		1000	13.13	1.90	32.13	19.04	2.60	45.07	12.94	40.3%
		1500	13.13	1.90	41.63	19.04	2.60	58.09	16.46	39.5%
		2000	13.13	1.90	51.13	19.04	2.60	71.10	19.97	39.1%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Exeter**	100	15.10	0.96	16.06	19.04	2.60	21.64	5.58	34.8%
		250	15.10	0.96	17.50	19.04	2.60	25.55	8.05	46.0%
		500	15.10	0.96	19.90	19.04	2.60	32.06	12.16	61.1%
		750	15.10	0.96	22.30	19.04	2.60	38.56	16.26	72.9%
		1000	15.10	0.96	24.70	19.04	2.60	45.07	20.37	82.5%
		1500	15.10	0.96	29.50	19.04	2.60	58.09	28.59	96.9%
		2000	15.10	0.96	34.30	19.04	2.60	71.10	36.80	107.3%
R1	**Fenelon Falls**	100	6.09	0.96	7.05	19.04	2.60	21.64	14.59	207.0%
		250	6.09	0.96	8.49	19.04	2.60	25.55	17.06	200.9%
		500	6.09	0.96	10.89	19.04	2.60	32.06	21.17	194.4%
		750	6.09	0.96	13.29	19.04	2.60	38.56	25.27	190.2%
		1000	6.09	0.96	15.69	19.04	2.60	45.07	29.38	187.3%
		1500	6.09	0.96	20.49	19.04	2.60	58.09	37.60	183.5%
		2000	6.09	0.96	25.29	19.04	2.60	71.10	45.81	181.2%
R1	**Forest**	100	15.26	0.95	16.21	19.04	2.60	21.64	5.43	33.5%
		250	15.26	0.95	17.64	19.04	2.60	25.55	7.91	44.9%
		500	15.26	0.95	20.01	19.04	2.60	32.06	12.05	60.2%
		750	15.26	0.95	22.39	19.04	2.60	38.56	16.18	72.3%
		1000	15.26	0.95	24.76	19.04	2.60	45.07	20.31	82.0%
		1500	15.26	0.95	29.51	19.04	2.60	58.09	28.58	96.8%
		2000	15.26	0.95	34.26	19.04	2.60	71.10	36.84	107.5%
UR	**GBE**	100	9.68	0.95	10.63	19.04	2.60	21.64	11.01	103.6%
		250	9.68	0.95	12.06	19.04	2.60	25.55	13.49	111.9%
		500	9.68	0.95	14.43	19.04	2.60	32.06	17.63	122.1%
		750	9.68	0.95	16.81	19.04	2.60	38.56	21.76	129.5%
		1000	9.68	0.95	19.18	19.04	2.60	45.07	25.89	135.0%
		1500	9.68	0.95	23.93	19.04	2.60	58.09	34.16	142.7%
		2000	9.68	0.95	28.68	19.04	2.60	71.10	42.42	147.9%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Georgina**	100	11.72	0.98	12.70	19.04	2.60	21.64	8.94	70.4%
		250	11.72	0.98	14.17	19.04	2.60	25.55	11.38	80.3%
		500	11.72	0.98	16.62	19.04	2.60	32.06	15.44	92.9%
		750	11.72	0.98	19.07	19.04	2.60	38.56	19.49	102.2%
		1000	11.72	0.98	21.52	19.04	2.60	45.07	23.55	109.4%
		1500	11.72	0.98	26.42	19.04	2.60	58.09	31.67	119.9%
		2000	11.72	0.98	31.32	19.04	2.60	71.10	39.78	127.0%
R1	**Glencoe**	100	12.90	0.77	13.67	19.04	2.60	21.64	7.97	58.3%
		250	12.90	0.77	14.83	19.04	2.60	25.55	10.72	72.3%
		500	12.90	0.77	16.75	19.04	2.60	32.06	15.31	91.4%
		750	12.90	0.77	18.68	19.04	2.60	38.56	19.89	106.5%
		1000	12.90	0.77	20.60	19.04	2.60	45.07	24.47	118.8%
		1500	12.90	0.77	24.45	19.04	2.60	58.09	33.64	137.6%
		2000	12.90	0.77	28.30	19.04	2.60	71.10	42.80	151.2%
R1	**Grand Bend**	100	13.58	0.87	14.45	19.04	2.60	21.64	7.19	49.8%
		250	13.58	0.87	15.76	19.04	2.60	25.55	9.79	62.2%
		500	13.58	0.87	17.93	19.04	2.60	32.06	14.13	78.8%
		750	13.58	0.87	20.11	19.04	2.60	38.56	18.46	91.8%
		1000	13.58	0.87	22.28	19.04	2.60	45.07	22.79	102.3%
		1500	13.58	0.87	26.63	19.04	2.60	58.09	31.46	118.1%
		2000	13.58	0.87	30.98	19.04	2.60	71.10	40.12	129.5%
R1	**Hastings**	100	16.44	1.35	17.79	19.04	2.60	21.64	3.85	21.7%
		250	16.44	1.35	19.82	19.04	2.60	25.55	5.73	28.9%
		500	16.44	1.35	23.19	19.04	2.60	32.06	8.87	38.2%
		750	16.44	1.35	26.57	19.04	2.60	38.56	12.00	45.2%
		1000	16.44	1.35	29.94	19.04	2.60	45.07	15.13	50.5%
		1500	16.44	1.35	36.69	19.04	2.60	58.09	21.40	58.3%
		2000	16.44	1.35	43.44	19.04	2.60	71.10	27.66	63.7%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Havelock**	100	15.17	1.14	16.31	19.04	2.60	21.64	5.33	32.7%
		250	15.17	1.14	18.02	19.04	2.60	25.55	7.53	41.8%
		500	15.17	1.14	20.87	19.04	2.60	32.06	11.19	53.6%
		750	15.17	1.14	23.72	19.04	2.60	38.56	14.84	62.6%
		1000	15.17	1.14	26.57	19.04	2.60	45.07	18.50	69.6%
		1500	15.17	1.14	32.27	19.04	2.60	58.09	25.82	80.0%
		2000	15.17	1.14	37.97	19.04	2.60	71.10	33.13	87.3%
R1	**Kirkfield**	100	5.34	1.00	6.34	19.04	2.60	21.64	15.30	241.4%
		250	5.34	1.00	7.84	19.04	2.60	25.55	17.71	225.9%
		500	5.34	1.00	10.34	19.04	2.60	32.06	21.72	210.0%
		750	5.34	1.00	12.84	19.04	2.60	38.56	25.72	200.3%
		1000	5.34	1.00	15.34	19.04	2.60	45.07	29.73	193.8%
		1500	5.34	1.00	20.34	19.04	2.60	58.09	37.75	185.6%
		2000	5.34	1.00	25.34	19.04	2.60	71.10	45.76	180.6%
R1	**Lanark Highlands**	100	11.31	1.02	12.33	19.04	2.60	21.64	9.31	75.5%
		250	11.31	1.02	13.86	19.04	2.60	25.55	11.69	84.3%
		500	11.31	1.02	16.41	19.04	2.60	32.06	15.65	95.3%
		750	11.31	1.02	18.96	19.04	2.60	38.56	19.60	103.4%
		1000	11.31	1.02	21.51	19.04	2.60	45.07	23.56	109.5%
		1500	11.31	1.02	26.61	19.04	2.60	58.09	31.48	118.3%
		2000	11.31	1.02	31.71	19.04	2.60	71.10	39.39	124.2%
R1	**Larder Lake**	100	15.84	1.01	16.85	19.04	2.60	21.64	4.79	28.4%
		250	15.84	1.01	18.37	19.04	2.60	25.55	7.18	39.1%
		500	15.84	1.01	20.89	19.04	2.60	32.06	11.17	53.5%
		750	15.84	1.01	23.42	19.04	2.60	38.56	15.15	64.7%
		1000	15.84	1.01	25.94	19.04	2.60	45.07	19.13	73.8%
		1500	15.84	1.01	30.99	19.04	2.60	58.09	27.10	87.4%
		2000	15.84	1.01	36.04	19.04	2.60	71.10	35.06	97.3%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Latchford**	100	13.31	0.88	14.19	19.04	2.60	21.64	7.45	52.5%
		250	13.31	0.88	15.51	19.04	2.60	25.55	10.04	64.7%
		500	13.31	0.88	17.71	19.04	2.60	32.06	14.35	81.0%
		750	13.31	0.88	19.91	19.04	2.60	38.56	18.65	93.7%
		1000	13.31	0.88	22.11	19.04	2.60	45.07	22.96	103.9%
		1500	13.31	0.88	26.51	19.04	2.60	58.09	31.58	119.1%
		2000	13.31	0.88	30.91	19.04	2.60	71.10	40.19	130.0%
UR	**Lindsay**	100	15.81	1.01	16.82	19.04	2.60	21.64	4.82	28.7%
		250	15.81	1.01	18.34	19.04	2.60	25.55	7.21	39.3%
		500	15.81	1.01	20.86	19.04	2.60	32.06	11.20	53.7%
		750	15.81	1.01	23.39	19.04	2.60	38.56	15.18	64.9%
		1000	15.81	1.01	25.91	19.04	2.60	45.07	19.16	74.0%
		1500	15.81	1.01	30.96	19.04	2.60	58.09	27.13	87.6%
		2000	15.81	1.01	36.01	19.04	2.60	71.10	35.09	97.5%
R1	**Lucan Granton**	100	11.72	1.42	13.14	19.04	2.60	21.64	8.50	64.7%
		250	11.72	1.42	15.27	19.04	2.60	25.55	10.28	67.3%
		500	11.72	1.42	18.82	19.04	2.60	32.06	13.24	70.3%
		750	11.72	1.42	22.37	19.04	2.60	38.56	16.19	72.4%
		1000	11.72	1.42	25.92	19.04	2.60	45.07	19.15	73.9%
		1500	11.72	1.42	33.02	19.04	2.60	58.09	25.07	75.9%
		2000	11.72	1.42	40.12	19.04	2.60	71.10	30.98	77.2%
R1	**Malahide**	100	11.17	0.87	12.04	19.04	2.60	21.64	9.60	79.8%
		250	11.17	0.87	13.35	19.04	2.60	25.55	12.20	91.4%
		500	11.17	0.87	15.52	19.04	2.60	32.06	16.54	106.5%
		750	11.17	0.87	17.70	19.04	2.60	38.56	20.87	117.9%
		1000	11.17	0.87	19.87	19.04	2.60	45.07	25.20	126.8%
		1500	11.17	0.87	24.22	19.04	2.60	58.09	33.87	139.8%
		2000	11.17	0.87	28.57	19.04	2.60	71.10	42.53	148.9%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Mapleton**	100	13.47	0.92	14.39	19.04	2.60	21.64	7.25	50.4%
		250	13.47	0.92	15.77	19.04	2.60	25.55	9.78	62.0%
		500	13.47	0.92	18.07	19.04	2.60	32.06	13.99	77.4%
		750	13.47	0.92	20.37	19.04	2.60	38.56	18.19	89.3%
		1000	13.47	0.92	22.67	19.04	2.60	45.07	22.40	98.8%
		1500	13.47	0.92	27.27	19.04	2.60	58.09	30.82	113.0%
		2000	13.47	0.92	31.87	19.04	2.60	71.10	39.23	123.1%
R1	**Markdale**	100	14.30	0.86	15.16	19.04	2.60	21.64	6.48	42.8%
		250	14.30	0.86	16.45	19.04	2.60	25.55	9.10	55.3%
		500	14.30	0.86	18.60	19.04	2.60	32.06	13.46	72.3%
		750	14.30	0.86	20.75	19.04	2.60	38.56	17.81	85.8%
		1000	14.30	0.86	22.90	19.04	2.60	45.07	22.17	96.8%
		1500	14.30	0.86	27.20	19.04	2.60	58.09	30.89	113.6%
		2000	14.30	0.86	31.50	19.04	2.60	71.10	39.60	125.7%
R1	**Marmora**	100	11.59	0.92	12.51	19.04	2.60	21.64	9.13	73.0%
		250	11.59	0.92	13.89	19.04	2.60	25.55	11.66	83.9%
		500	11.59	0.92	16.19	19.04	2.60	32.06	15.87	98.0%
		750	11.59	0.92	18.49	19.04	2.60	38.56	20.07	108.6%
		1000	11.59	0.92	20.79	19.04	2.60	45.07	24.28	116.8%
		1500	11.59	0.92	25.39	19.04	2.60	58.09	32.70	128.8%
		2000	11.59	0.92	29.99	19.04	2.60	71.10	41.11	137.1%
R1	**McGarry**	100	12.85	0.93	13.78	19.04	2.60	21.64	7.86	57.1%
		250	12.85	0.93	15.18	19.04	2.60	25.55	10.37	68.4%
		500	12.85	0.93	17.50	19.04	2.60	32.06	14.56	83.2%
		750	12.85	0.93	19.83	19.04	2.60	38.56	18.74	94.5%
		1000	12.85	0.93	22.15	19.04	2.60	45.07	22.92	103.5%
		1500	12.85	0.93	26.80	19.04	2.60	58.09	31.29	116.7%
		2000	12.85	0.93	31.45	19.04	2.60	71.10	39.65	126.1%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Meaford**	100	12.75	0.97	13.72	19.04	2.60	21.64	7.92	57.7%
		250	12.75	0.97	15.18	19.04	2.60	25.55	10.37	68.4%
		500	12.75	0.97	17.60	19.04	2.60	32.06	14.46	82.1%
		750	12.75	0.97	20.03	19.04	2.60	38.56	18.54	92.6%
		1000	12.75	0.97	22.45	19.04	2.60	45.07	22.62	100.8%
		1500	12.75	0.97	27.30	19.04	2.60	58.09	30.79	112.8%
		2000	12.75	0.97	32.15	19.04	2.60	71.10	38.95	121.2%
R1	**Middlesex Centre**	100	14.19	0.78	14.97	19.04	2.60	21.64	6.67	44.6%
		250	14.19	0.78	16.14	19.04	2.60	25.55	9.41	58.3%
		500	14.19	0.78	18.09	19.04	2.60	32.06	13.97	77.2%
		750	14.19	0.78	20.04	19.04	2.60	38.56	18.52	92.4%
		1000	14.19	0.78	21.99	19.04	2.60	45.07	23.08	105.0%
		1500	14.19	0.78	25.89	19.04	2.60	58.09	32.20	124.4%
		2000	14.19	0.78	29.79	19.04	2.60	71.10	41.31	138.7%
R1	**Napanee**	100	14.70	1.02	15.72	19.04	2.60	21.64	5.92	37.7%
		250	14.70	1.02	17.25	19.04	2.60	25.55	8.30	48.1%
		500	14.70	1.02	19.80	19.04	2.60	32.06	12.26	61.9%
		750	14.70	1.02	22.35	19.04	2.60	38.56	16.21	72.5%
		1000	14.70	1.02	24.90	19.04	2.60	45.07	20.17	81.0%
		1500	14.70	1.02	30.00	19.04	2.60	58.09	28.09	93.6%
		2000	14.70	1.02	35.10	19.04	2.60	71.10	36.00	102.6%
R1	**Nipigon**	100	14.23	1.42	15.65	19.04	2.60	21.64	5.99	38.3%
		250	14.23	1.42	17.78	19.04	2.60	25.55	7.77	43.7%
		500	14.23	1.42	21.33	19.04	2.60	32.06	10.73	50.3%
		750	14.23	1.42	24.88	19.04	2.60	38.56	13.68	55.0%
		1000	14.23	1.42	28.43	19.04	2.60	45.07	16.64	58.5%
		1500	14.23	1.42	35.53	19.04	2.60	58.09	22.56	63.5%
		2000	14.23	1.42	42.63	19.04	2.60	71.10	28.47	66.8%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**North Dorchester**	100	8.97	0.86	9.83	19.04	2.60	21.64	11.81	120.2%
		250	8.97	0.86	11.12	19.04	2.60	25.55	14.43	129.7%
		500	8.97	0.86	13.27	19.04	2.60	32.06	18.79	141.6%
		750	8.97	0.86	15.42	19.04	2.60	38.56	23.14	150.1%
		1000	8.97	0.86	17.57	19.04	2.60	45.07	27.50	156.5%
		1500	8.97	0.86	21.87	19.04	2.60	58.09	36.22	165.6%
		2000	8.97	0.86	26.17	19.04	2.60	71.10	44.93	171.7%
R1	**North Dundas**	100	11.17	0.97	12.14	19.04	2.60	21.64	9.50	78.3%
		250	11.17	0.97	13.60	19.04	2.60	25.55	11.95	87.9%
		500	11.17	0.97	16.02	19.04	2.60	32.06	16.04	100.1%
		750	11.17	0.97	18.45	19.04	2.60	38.56	20.12	109.1%
		1000	11.17	0.97	20.87	19.04	2.60	45.07	24.20	116.0%
		1500	11.17	0.97	25.72	19.04	2.60	58.09	32.37	125.8%
		2000	11.17	0.97	30.57	19.04	2.60	71.10	40.53	132.6%
R1	**North Glengarry**	100	7.74	1.02	8.76	19.04	2.60	21.64	12.88	147.1%
		250	7.74	1.02	10.29	19.04	2.60	25.55	15.26	148.3%
		500	7.74	1.02	12.84	19.04	2.60	32.06	19.22	149.7%
		750	7.74	1.02	15.39	19.04	2.60	38.56	23.17	150.6%
		1000	7.74	1.02	17.94	19.04	2.60	45.07	27.13	151.2%
		1500	7.74	1.02	23.04	19.04	2.60	58.09	35.05	152.1%
		2000	7.74	1.02	28.14	19.04	2.60	71.10	42.96	152.7%
R1	**North Grenville**	100	14.40	1.65	16.05	19.04	2.60	21.64	5.59	34.8%
		250	14.40	1.65	18.53	19.04	2.60	25.55	7.02	37.9%
		500	14.40	1.65	22.65	19.04	2.60	32.06	9.41	41.5%
		750	14.40	1.65	26.78	19.04	2.60	38.56	11.79	44.0%
		1000	14.40	1.65	30.90	19.04	2.60	45.07	14.17	45.9%
		1500	14.40	1.65	39.15	19.04	2.60	58.09	18.94	48.4%
		2000	14.40	1.65	47.40	19.04	2.60	71.10	23.70	50.0%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**North Perth**	100	14.73	1.05	15.78	19.04	2.60	21.64	5.86	37.2%
		250	14.73	1.05	17.36	19.04	2.60	25.55	8.19	47.2%
		500	14.73	1.05	19.98	19.04	2.60	32.06	12.08	60.4%
		750	14.73	1.05	22.61	19.04	2.60	38.56	15.96	70.6%
		1000	14.73	1.05	25.23	19.04	2.60	45.07	19.84	78.6%
		1500	14.73	1.05	30.48	19.04	2.60	58.09	27.61	90.6%
		2000	14.73	1.05	35.73	19.04	2.60	71.10	35.37	99.0%
R1	**North Stormont**	100	5.42	0.92	6.34	19.04	2.60	21.64	15.30	241.4%
		250	5.42	0.92	7.72	19.04	2.60	25.55	17.83	230.9%
		500	5.42	0.92	10.02	19.04	2.60	32.06	22.04	219.9%
		750	5.42	0.92	12.32	19.04	2.60	38.56	26.24	213.0%
		1000	5.42	0.92	14.62	19.04	2.60	45.07	30.45	208.3%
		1500	5.42	0.92	19.22	19.04	2.60	58.09	38.87	202.2%
		2000	5.42	0.92	23.82	19.04	2.60	71.10	47.28	198.5%
R1	**Omemee**	100	14.99	1.50	16.49	19.04	2.60	21.64	5.15	31.3%
		250	14.99	1.50	18.74	19.04	2.60	25.55	6.81	36.3%
		500	14.99	1.50	22.49	19.04	2.60	32.06	9.57	42.5%
		750	14.99	1.50	26.24	19.04	2.60	38.56	12.32	47.0%
		1000	14.99	1.50	29.99	19.04	2.60	45.07	15.08	50.3%
		1500	14.99	1.50	37.49	19.04	2.60	58.09	20.60	54.9%
		2000	14.99	1.50	44.99	19.04	2.60	71.10	26.11	58.0%
UR	**Perth**	100	14.47	1.22	15.69	19.04	2.60	21.64	5.95	37.9%
		250	14.47	1.22	17.52	19.04	2.60	25.55	8.03	45.8%
		500	14.47	1.22	20.57	19.04	2.60	32.06	11.49	55.8%
		750	14.47	1.22	23.62	19.04	2.60	38.56	14.94	63.3%
		1000	14.47	1.22	26.67	19.04	2.60	45.07	18.40	69.0%
		1500	14.47	1.22	32.77	19.04	2.60	58.09	25.32	77.3%
		2000	14.47	1.22	38.87	19.04	2.60	71.10	32.23	82.9%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Perth East**	100	5.95	0.78	6.73	19.04	2.60	21.64	14.91	221.6%
		250	5.95	0.78	7.90	19.04	2.60	25.55	17.65	223.4%
		500	5.95	0.78	9.85	19.04	2.60	32.06	22.21	225.4%
		750	5.95	0.78	11.80	19.04	2.60	38.56	26.76	226.8%
		1000	5.95	0.78	13.75	19.04	2.60	45.07	31.32	227.8%
		1500	5.95	0.78	17.65	19.04	2.60	58.09	40.44	229.1%
		2000	5.95	0.78	21.55	19.04	2.60	71.10	49.55	229.9%
R1	**Prince Edward**	100	14.25	1.05	15.30	19.04	2.60	21.64	6.34	41.5%
		250	14.25	1.05	16.88	19.04	2.60	25.55	8.67	51.4%
		500	14.25	1.05	19.50	19.04	2.60	32.06	12.56	64.4%
		750	14.25	1.05	22.13	19.04	2.60	38.56	16.44	74.3%
		1000	14.25	1.05	24.75	19.04	2.60	45.07	20.32	82.1%
		1500	14.25	1.05	30.00	19.04	2.60	58.09	28.09	93.6%
		2000	14.25	1.05	35.25	19.04	2.60	71.10	35.85	101.7%
UR	**Quinte West**	100	6.58	0.92	7.50	19.04	2.60	21.64	14.14	188.6%
		250	6.58	0.92	8.88	19.04	2.60	25.55	16.67	187.7%
		500	6.58	0.92	11.18	19.04	2.60	32.06	20.88	186.7%
		750	6.58	0.92	13.48	19.04	2.60	38.56	25.08	186.1%
		1000	6.58	0.92	15.78	19.04	2.60	45.07	29.29	185.6%
		1500	6.58	0.92	20.38	19.04	2.60	58.09	37.71	185.0%
		2000	6.58	0.92	24.98	19.04	2.60	71.10	46.12	184.6%
R1	**Rainy River**	100	15.04	1.02	16.06	19.04	2.60	21.64	5.58	34.8%
		250	15.04	1.02	17.59	19.04	2.60	25.55	7.96	45.2%
		500	15.04	1.02	20.14	19.04	2.60	32.06	11.92	59.2%
		750	15.04	1.02	22.69	19.04	2.60	38.56	15.87	70.0%
		1000	15.04	1.02	25.24	19.04	2.60	45.07	19.83	78.6%
		1500	15.04	1.02	30.34	19.04	2.60	58.09	27.75	91.5%
		2000	15.04	1.02	35.44	19.04	2.60	71.10	35.66	100.6%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Ramara**	100	6.52	0.95	7.47	19.04	2.60	21.64	14.17	189.7%
		250	6.52	0.95	8.90	19.04	2.60	25.55	16.65	187.2%
		500	6.52	0.95	11.27	19.04	2.60	32.06	20.79	184.4%
		750	6.52	0.95	13.65	19.04	2.60	38.56	24.92	182.6%
		1000	6.52	0.95	16.02	19.04	2.60	45.07	29.05	181.3%
		1500	6.52	0.95	20.77	19.04	2.60	58.09	37.32	179.7%
		2000	6.52	0.95	25.52	19.04	2.60	71.10	45.58	178.6%
R1	**Red Rock**	100	15.21	2.07	17.28	19.04	2.60	21.64	4.36	25.2%
		250	15.21	2.07	20.39	19.04	2.60	25.55	5.16	25.3%
		500	15.21	2.07	25.56	19.04	2.60	32.06	6.50	25.4%
		750	15.21	2.07	30.74	19.04	2.60	38.56	7.83	25.5%
		1000	15.21	2.07	35.91	19.04	2.60	45.07	9.16	25.5%
		1500	15.21	2.07	46.26	19.04	2.60	58.09	11.83	25.6%
		2000	15.21	2.07	56.61	19.04	2.60	71.10	14.49	25.6%
R1	**Rockland**	100	9.41	0.92	10.33	19.04	2.60	21.64	11.31	109.5%
		250	9.41	0.92	11.71	19.04	2.60	25.55	13.84	118.2%
		500	9.41	0.92	14.01	19.04	2.60	32.06	18.05	128.8%
		750	9.41	0.92	16.31	19.04	2.60	38.56	22.25	136.4%
		1000	9.41	0.92	18.61	19.04	2.60	45.07	26.46	142.2%
		1500	9.41	0.92	23.21	19.04	2.60	58.09	34.88	150.3%
		2000	9.41	0.92	27.81	19.04	2.60	71.10	43.29	155.7%
R1	**Russell**	100	13.11	1.44	14.55	19.04	2.60	21.64	7.09	48.8%
		250	13.11	1.44	16.71	19.04	2.60	25.55	8.84	52.9%
		500	13.11	1.44	20.31	19.04	2.60	32.06	11.75	57.8%
		750	13.11	1.44	23.91	19.04	2.60	38.56	14.65	61.3%
		1000	13.11	1.44	27.51	19.04	2.60	45.07	17.56	63.8%
		1500	13.11	1.44	34.71	19.04	2.60	58.09	23.38	67.4%
		2000	13.11	1.44	41.91	19.04	2.60	71.10	29.19	69.7%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Schreiber**	100	16.32	1.84	18.16	19.04	2.60	21.64	3.48	19.2%
		250	16.32	1.84	20.92	19.04	2.60	25.55	4.63	22.1%
		500	16.32	1.84	25.52	19.04	2.60	32.06	6.54	25.6%
		750	16.32	1.84	30.12	19.04	2.60	38.56	8.44	28.0%
		1000	16.32	1.84	34.72	19.04	2.60	45.07	10.35	29.8%
		1500	16.32	1.84	43.92	19.04	2.60	58.09	14.17	32.3%
		2000	16.32	1.84	53.12	19.04	2.60	71.10	17.98	33.9%
R1	**Severn**	100	10.60	0.90	11.50	19.04	2.60	21.64	10.14	88.2%
		250	10.60	0.90	12.85	19.04	2.60	25.55	12.70	98.8%
		500	10.60	0.90	15.10	19.04	2.60	32.06	16.96	112.3%
		750	10.60	0.90	17.35	19.04	2.60	38.56	21.21	122.3%
		1000	10.60	0.90	19.60	19.04	2.60	45.07	25.47	130.0%
		1500	10.60	0.90	24.10	19.04	2.60	58.09	33.99	141.0%
		2000	10.60	0.90	28.60	19.04	2.60	71.10	42.50	148.6%
R1	**Shelburne**	100	14.14	1.33	15.47	19.04	2.60	21.64	6.17	39.9%
		250	14.14	1.33	17.47	19.04	2.60	25.55	8.08	46.3%
		500	14.14	1.33	20.79	19.04	2.60	32.06	11.27	54.2%
		750	14.14	1.33	24.12	19.04	2.60	38.56	14.45	59.9%
		1000	14.14	1.33	27.44	19.04	2.60	45.07	17.63	64.3%
		1500	14.14	1.33	34.09	19.04	2.60	58.09	24.00	70.4%
		2000	14.14	1.33	40.74	19.04	2.60	71.10	30.36	74.5%
UR	**Smiths Falls**	100	12.63	1.42	14.05	19.04	2.60	21.64	7.59	54.0%
		250	12.63	1.42	16.18	19.04	2.60	25.55	9.37	57.9%
		500	12.63	1.42	19.73	19.04	2.60	32.06	12.33	62.5%
		750	12.63	1.42	23.28	19.04	2.60	38.56	15.28	65.7%
		1000	12.63	1.42	26.83	19.04	2.60	45.07	18.24	68.0%
		1500	12.63	1.42	33.93	19.04	2.60	58.09	24.16	71.2%
		2000	12.63	1.42	41.03	19.04	2.60	71.10	30.07	73.3%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**South Glengarry**	100	9.46	0.75	10.21	19.04	2.60	21.64	11.43	112.0%
		250	9.46	0.75	11.34	19.04	2.60	25.55	14.21	125.4%
		500	9.46	0.75	13.21	19.04	2.60	32.06	18.85	142.7%
		750	9.46	0.75	15.09	19.04	2.60	38.56	23.48	155.6%
		1000	9.46	0.75	16.96	19.04	2.60	45.07	28.11	165.8%
		1500	9.46	0.75	20.71	19.04	2.60	58.09	37.38	180.5%
		2000	9.46	0.75	24.46	19.04	2.60	71.10	46.64	190.7%
R1	**South River**	100	14.22	1.25	15.47	19.04	2.60	21.64	6.17	39.9%
		250	14.22	1.25	17.35	19.04	2.60	25.55	8.20	47.3%
		500	14.22	1.25	20.47	19.04	2.60	32.06	11.59	56.6%
		750	14.22	1.25	23.60	19.04	2.60	38.56	14.97	63.4%
		1000	14.22	1.25	26.72	19.04	2.60	45.07	18.35	68.7%
		1500	14.22	1.25	32.97	19.04	2.60	58.09	25.12	76.2%
		2000	14.22	1.25	39.22	19.04	2.60	71.10	31.88	81.3%
R1	**Springwater**	100	11.79	0.82	12.61	19.04	2.60	21.64	9.03	71.6%
		250	11.79	0.82	13.84	19.04	2.60	25.55	11.71	84.6%
		500	11.79	0.82	15.89	19.04	2.60	32.06	16.17	101.7%
		750	11.79	0.82	17.94	19.04	2.60	38.56	20.62	115.0%
		1000	11.79	0.82	19.99	19.04	2.60	45.07	25.08	125.5%
		1500	11.79	0.82	24.09	19.04	2.60	58.09	34.00	141.1%
		2000	11.79	0.82	28.19	19.04	2.60	71.10	42.91	152.2%
R1	**Stirling-Rawdon**	100	12.55	1.03	13.58	19.04	2.60	21.64	8.06	59.4%
		250	12.55	1.03	15.13	19.04	2.60	25.55	10.42	68.9%
		500	12.55	1.03	17.70	19.04	2.60	32.06	14.36	81.1%
		750	12.55	1.03	20.28	19.04	2.60	38.56	18.29	90.2%
		1000	12.55	1.03	22.85	19.04	2.60	45.07	22.22	97.3%
		1500	12.55	1.03	28.00	19.04	2.60	58.09	30.09	107.5%
		2000	12.55	1.03	33.15	19.04	2.60	71.10	37.95	114.5%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Thedford**	100	12.75	0.81	13.56	19.04	2.60	21.64	8.08	59.6%
		250	12.75	0.81	14.78	19.04	2.60	25.55	10.77	72.9%
		500	12.75	0.81	16.80	19.04	2.60	32.06	15.26	90.8%
		750	12.75	0.81	18.83	19.04	2.60	38.56	19.74	104.9%
		1000	12.75	0.81	20.85	19.04	2.60	45.07	24.22	116.2%
		1500	12.75	0.81	24.90	19.04	2.60	58.09	33.19	133.3%
		2000	12.75	0.81	28.95	19.04	2.60	71.10	42.15	145.6%
R1	**Thessalon**	100	15.56	1.05	16.61	19.04	2.60	21.64	5.03	30.3%
		250	15.56	1.05	18.19	19.04	2.60	25.55	7.36	40.5%
		500	15.56	1.05	20.81	19.04	2.60	32.06	11.25	54.0%
		750	15.56	1.05	23.44	19.04	2.60	38.56	15.13	64.6%
		1000	15.56	1.05	26.06	19.04	2.60	45.07	19.01	73.0%
		1500	15.56	1.05	31.31	19.04	2.60	58.09	26.78	85.5%
		2000	15.56	1.05	36.56	19.04	2.60	71.10	34.54	94.5%
R1	**Thorndale**	100	4.32	0.88	5.20	19.04	2.60	21.64	16.44	316.2%
		250	4.32	0.88	6.52	19.04	2.60	25.55	19.03	291.8%
		500	4.32	0.88	8.72	19.04	2.60	32.06	23.34	267.6%
		750	4.32	0.88	10.92	19.04	2.60	38.56	27.64	253.1%
		1000	4.32	0.88	13.12	19.04	2.60	45.07	31.95	243.5%
		1500	4.32	0.88	17.52	19.04	2.60	58.09	40.57	231.6%
		2000	4.32	0.88	21.92	19.04	2.60	71.10	49.18	224.4%
UR	**Thorold**	100	13.68	1.47	15.15	19.04	2.60	21.64	6.49	42.9%
		250	13.68	1.47	17.36	19.04	2.60	25.55	8.19	47.2%
		500	13.68	1.47	21.03	19.04	2.60	32.06	11.03	52.4%
		750	13.68	1.47	24.71	19.04	2.60	38.56	13.86	56.1%
		1000	13.68	1.47	28.38	19.04	2.60	45.07	16.69	58.8%
		1500	13.68	1.47	35.73	19.04	2.60	58.09	22.36	62.6%
		2000	13.68	1.47	43.08	19.04	2.60	71.10	28.02	65.1%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Tweed**	100	4.48	0.95	5.43	19.04	2.60	21.64	16.21	298.6%
		250	4.48	0.95	6.86	19.04	2.60	25.55	18.69	272.7%
		500	4.48	0.95	9.23	19.04	2.60	32.06	22.83	247.3%
		750	4.48	0.95	11.61	19.04	2.60	38.56	26.96	232.3%
		1000	4.48	0.95	13.98	19.04	2.60	45.07	31.09	222.4%
		1500	4.48	0.95	18.73	19.04	2.60	58.09	39.36	210.1%
		2000	4.48	0.95	23.48	19.04	2.60	71.10	47.62	202.8%
R1	**Wardsville**	100	9.64	0.97	10.61	19.04	2.60	21.64	11.03	104.0%
		250	9.64	0.97	12.07	19.04	2.60	25.55	13.48	111.8%
		500	9.64	0.97	14.49	19.04	2.60	32.06	17.57	121.2%
		750	9.64	0.97	16.92	19.04	2.60	38.56	21.65	128.0%
		1000	9.64	0.97	19.34	19.04	2.60	45.07	25.73	133.0%
		1500	9.64	0.97	24.19	19.04	2.60	58.09	33.90	140.1%
		2000	9.64	0.97	29.04	19.04	2.60	71.10	42.06	144.8%
R1	**Warkworth**	100	15.25	1.18	16.43	19.04	2.60	21.64	5.21	31.7%
		250	15.25	1.18	18.20	19.04	2.60	25.55	7.35	40.4%
		500	15.25	1.18	21.15	19.04	2.60	32.06	10.91	51.6%
		750	15.25	1.18	24.10	19.04	2.60	38.56	14.46	60.0%
		1000	15.25	1.18	27.05	19.04	2.60	45.07	18.02	66.6%
		1500	15.25	1.18	32.95	19.04	2.60	58.09	25.14	76.3%
		2000	15.25	1.18	38.85	19.04	2.60	71.10	32.25	83.0%
R1	**West Elgin**	100	13.30	1.42	14.72	19.04	2.60	21.64	6.92	47.0%
		250	13.30	1.42	16.85	19.04	2.60	25.55	8.70	51.6%
		500	13.30	1.42	20.40	19.04	2.60	32.06	11.66	57.1%
		750	13.30	1.42	23.95	19.04	2.60	38.56	14.61	61.0%
		1000	13.30	1.42	27.50	19.04	2.60	45.07	17.57	63.9%
		1500	13.30	1.42	34.60	19.04	2.60	58.09	23.49	67.9%
		2000	13.30	1.42	41.70	19.04	2.60	71.10	29.40	70.5%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
UR	**Whitchurch Stouffville**	100	10.54	1.02	11.56	19.04	2.60	21.64	10.08	87.2%
		250	10.54	1.02	13.09	19.04	2.60	25.55	12.46	95.2%
		500	10.54	1.02	15.64	19.04	2.60	32.06	16.42	105.0%
		750	10.54	1.02	18.19	19.04	2.60	38.56	20.37	112.0%
		1000	10.54	1.02	20.74	19.04	2.60	45.07	24.33	117.3%
		1500	10.54	1.02	25.84	19.04	2.60	58.09	32.25	124.8%
		2000	10.54	1.02	30.94	19.04	2.60	71.10	40.16	129.8%
R1	**Wiarton**	100	15.83	1.55	17.38	19.04	2.60	21.64	4.26	24.5%
		250	15.83	1.55	19.71	19.04	2.60	25.55	5.84	29.7%
		500	15.83	1.55	23.58	19.04	2.60	32.06	8.48	35.9%
		750	15.83	1.55	27.46	19.04	2.60	38.56	11.11	40.5%
		1000	15.83	1.55	31.33	19.04	2.60	45.07	13.74	43.9%
		1500	15.83	1.55	39.08	19.04	2.60	58.09	19.01	48.6%
		2000	15.83	1.55	46.83	19.04	2.60	71.10	24.27	51.8%
R1	**Woodville**	100	3.78	0.95	4.73	19.04	2.60	21.64	16.91	357.6%
		250	3.78	0.95	6.16	19.04	2.60	25.55	19.39	315.1%
		500	3.78	0.95	8.53	19.04	2.60	32.06	23.53	275.8%
		750	3.78	0.95	10.91	19.04	2.60	38.56	27.66	253.6%
		1000	3.78	0.95	13.28	19.04	2.60	45.07	31.79	239.4%
		1500	3.78	0.95	18.03	19.04	2.60	58.09	40.06	222.2%
		2000	3.78	0.95	22.78	19.04	2.60	71.10	48.32	212.1%
R1	**Wyoming**	100	11.52	0.81	12.33	19.04	2.60	21.64	9.31	75.5%
		250	11.52	0.81	13.55	19.04	2.60	25.55	12.00	88.6%
		500	11.52	0.81	15.57	19.04	2.60	32.06	16.49	105.9%
		750	11.52	0.81	17.60	19.04	2.60	38.56	20.97	119.2%
		1000	11.52	0.81	19.62	19.04	2.60	45.07	25.45	129.7%
		1500	11.52	0.81	23.67	19.04	2.60	58.09	34.42	145.4%
		2000	11.52	0.81	27.72	19.04	2.60	71.10	43.38	156.5%

New Rate Class: R1

Bill Impacts of Target Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Target Dx Rates			$ Incr	% Incr
New Class	**Old Class**	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R1	**Terrace Bay**	100	20.81	1.45	22.26	19.04	2.60	21.64	(0.62)	-2.8%
		250	20.81	1.45	24.44	19.04	2.60	25.55	1.11	4.6%
		500	20.81	1.45	28.06	19.04	2.60	32.06	4.00	14.2%
		750	20.81	1.45	31.69	19.04	2.60	38.56	6.88	21.7%
		1000	20.81	1.45	35.31	19.04	2.60	45.07	9.76	27.6%
		1500	20.81	1.45	42.56	19.04	2.60	58.09	15.53	36.5%
		2000	20.81	1.45	49.81	19.04	2.60	71.10	21.29	42.7%

New Rate Class: R2

Bill Impacts of Proposed Distribution Rates excluding Riders

Classes		Scenario	Existing Dx Rates			Proposed Dx Rates			$ Incr	% Incr
New Class	Old Class	kWh	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]	SrChg [$/month]	base [c/kWh]	Dx bill [$/month]		
R2	R2	100	29.22	1.94	31.16	21.41	3.10	24.50	(6.66)	-21.4%
		250	29.22	1.94	34.07	21.41	3.10	29.14	(4.93)	-14.5%
		500	29.22	1.94	38.92	21.41	3.10	36.88	(2.04)	-5.2%
		750	29.22	1.94	43.77	21.41	3.10	44.62	0.85	1.9%
		1,000	29.22	1.94	48.62	21.41	3.10	52.36	3.74	7.7%
		1,500	29.22	1.94	58.32	21.41	3.10	67.84	9.52	16.3%
		2,000	29.22	1.94	68.02	21.41	3.10	83.31	15.29	22.5%
R2	F1	100	28.61	2.24	30.85	21.41	3.10	24.50	(6.35)	-20.6%
		250	28.61	2.24	34.21	21.41	3.10	29.14	(5.07)	-14.8%
		500	28.61	2.24	39.81	21.41	3.10	36.88	(2.93)	-7.4%
		750	28.61	2.24	45.41	21.41	3.10	44.62	(0.79)	-1.7%
		1,000	28.61	2.24	51.01	21.41	3.10	52.36	1.35	2.6%
		1,500	28.61	2.24	62.21	21.41	3.10	67.84	5.63	9.0%
		2,000	28.61	2.24	73.41	21.41	3.10	83.31	9.90	13.5%
R2	F3	100	30.16	2.89	33.05	21.41	3.10	24.50	(8.55)	-25.9%
		250	30.16	2.89	37.39	21.41	3.10	29.14	(8.24)	-22.0%
		500	30.16	2.89	44.61	21.41	3.10	36.88	(7.73)	-17.3%
		750	30.16	2.89	51.84	21.41	3.10	44.62	(7.21)	-13.9%
		1,000	30.16	2.89	59.06	21.41	3.10	52.36	(6.70)	-11.3%
		1,500	30.16	2.89	73.51	21.41	3.10	67.84	(5.67)	-7.7%
		2,000	30.16	2.89	87.96	21.41	3.10	83.31	(4.65)	-5.3%
R2	Caledon OH 06	100	34.85	0.50	35.35	21.41	3.10	24.50	(10.85)	-30.7%
		250	34.85	0.50	36.10	21.41	3.10	29.14	(6.96)	-19.3%
		500	34.85	0.50	37.35	21.41	3.10	36.88	(0.47)	-1.3%
		750	34.85	0.50	38.60	21.41	3.10	44.62	6.02	15.6%
		1,000	34.85	0.50	39.85	21.41	3.10	52.36	12.51	31.4%
		1,500	34.85	0.50	42.35	21.41	3.10	67.84	25.49	60.2%
		2,000	34.85	0.50	44.85	21.41	3.10	83.31	38.46	85.8%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #62 List 1

Interrogatory

Reference: Exhibit G1, Tab 7, Schedule 2

Question:

a) What is the "average customer per LDC rate class" used to determine the bill impacts (page 1, line 14)?

Response

a. The consumption levels used to determine the average total bill impacts is consistent with the Response to Exhibit H, Tab 12, Schedule 53 and represented below.

Class	kWh	kW	Load Factor
Residential	1,000		
GSe	2,000		
GSd	43,164	133	45%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #63 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 8, Schedule 1, pages 1-4
ii) Exhibit G1, Tab 7, Schedule 1, page 6, Table 4

Question:

a) Please provide a schedule similar to Table 4 (Reference (ii)), but based on the proposed 2008 mitigated distribution rates per Reference (i).

b) With respect to the UR class shown in Table 1 (Reference (i)), please explain the following:
- Since none of the average customers in the classes mapped to UR have total bill impacts exceeding 10% (per Reference (ii)), why are the target rates being "mitigated" for 2008?
- What is the basis for the "mitigated rates"?

c) With respect to the R1 class shown in Table 1 (Reference (i)), please explain the following:
- Since none of the average customers in the classes mapped to R1 have total bill impacts exceeding 10% (per Reference (ii)), why are the target rates being "mitigated" for 2008?
- What is the basis for the "mitigated rates"?

d) With respect to the R2 class shown in Table 1 (Reference (i)), please explain the
a. following:
- Since none of the average customers in the classes mapped to R2 have total bill impacts exceeding 10% (per Reference (ii)), why are the target rates being "mitigated" for 2008?
- What is the basis for the "mitigated rates"?

e) With respect to the R2 class charges shown in Table 1 (Reference (i)):
- What is meant by the footnote "Nominal fixed Charge"?
- What is the level of RRA for 2008?
- Why is there a range for the "Nominal fixed Charge" for Legacy customers proposed for 2008?
- Why is there a range of volumetric charges proposed for the R2 class for 2008, but no similar range for the UR and R1 classes?

f) Please confirm that the ranges shown in Table 4 (Reference (i)) for each customer class reflect the total impacts on the average customer in each of the existing

classes which is being mapped to the proposed class. If not, please explain the basis for the range.

g) With respect to the R2 class, please confirm that without mitigation the highest total bill impact for an average customer was 1.1% (per Reference (ii)), whereas after mitigation it is 9% (per Reference (i), Table 2). If this is not the case, please explain. If it is, please explain why such a mitigation plan for these customers is appropriate.

h) It is understood that there is a revenue requirement shortfall due to Hydro One's proposed revenue to cost ratios per Exhibit G1, Tab 3, Schedule 1, Table 2. However, is there also a further shortfall in revenues from Legacy retail customers as a result of the proposed 2008 Mitigated Distribution rates or do the proposed rates for each customers class yield the proposed revenue to cost ratios set out in Exhibit G1, Tab 3, Schedule 1, Table 2? If there is an additional shortfall, please provide a schedule setting out the calculation of the amount? Also, please confirm whether this amount will be recorded in the proposed deferral account (per Reference (i), page 2).

Response

a. Table 4 from Exhibit G1, Tab 7, Schedule 1, has been updated with impacts based on 2008 mitigated rates. There is no mitigation being proposed for DGen, Street Lights and Sentinel Lights so there values have not changed.

New Class	Existing Class	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
UR	UR	16.4%	8.8%	1.9%	1.5%
	R1	-11.4%	-15.2%	-6.0%	-6.3%
	R2	-21.9%	-25.3%	-10.2%	-10.6%
	F1 wRRA	-25.6%	-27.6%	-11.4%	-11.3%
R1	R1	7.7%	3.1%	0.8%	0.6%
R2	R2	10.5%	6.6%	2.5%	2.1%
	F1 wRRA	3.6%	1.1%	0.4%	0.4%
	F3 wRRA	-7.8%	-9.0%	-2.5%	-1.8%
Seasonal	R3	23.9%	18.3%	9.4%	9.8%
	R4	14.8%	11.1%	6.6%	7.0%
UGe	F1 nRRA	-48.5%	-50.7%	-19.9%	-21.5%

New Class	Existing Class	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
	G1	-44.8%	-47.3%	-17.8%	-19.2%
	G3	-49.7%	-50.9%	-19.1%	-20.0%
	UG	-22.4%	-24.5%	-7.3%	-8.8%
UGd	G1	-24.2%	-29.8%	-10.0%	-10.2%
	G3	-27.2%	-30.3%	-8.9%	-9.1%
	UG	-12.7%	-16.6%	-5.7%	-5.9%
GSe	F1 nRRA	10.6%	7.8%	3.1%	1.3%
	F3 nRRA	-0.2%	-1.8%	0.6%	-0.4%
	G1	0.5%	-2.4%	-0.9%	-2.4%
	G3	-1.8%	-3.2%	0.1%	-1.0%
	T	-13.7%	-14.1%	-8.5%	-9.1%
	Unmtr	36.5%	31.9%	13.7%	12.19%
GSd	F1 nRRA	28.4%	20.5%	3.3%	0.6%
	F3 nRRA	-14.8%	-17.2%	-5.3%	-8.3%
	F1 wRRA	30.1%	21.9%	3.5%	0.8%
	F3 wRRA	-14.6%	-17.0%	-5.2%	-8.2%
	G1	-3.5%	-7.9%	-3.7%	-5.6%
	G3	-6.8%	-9.4%	-2.8%	-4.7%
	T	6.5%	3.9%	1.1%	-1.0%
DGen	G3d	-28.3%	-28.9%	-7.1%	-12.7%
	Td	-23.4%	-23.9%	-14.8%	-30.9%
	G3e	32.2%	32.3%	17.4%	15.1%
	Te	-22.0%	-21.6%	-17.6%	-15.9%
	GS Eganville	110.0%	111.7%	109.3%	111.9%
Street Lgts	Street Lgts	17.1%	14.6%	4.9%	5.0%
	Terrace Bay	89.4%	48.8%	17.8%	21.9%
Sentinel Lgts	Sentinel Lgts	74.5%	70.9%	25.0%	25.0%

b. The mitigation is required to limit the impact to Acquired customers being mapped to the new rate class. To mitigate the impacts, a lower service charge was introduced and a higher common variable charge was used to achieve the class revenue requirement.

c. Same answer as to Part b.

d. Same answer as to Part b.

e. With respect to the R2 rate class
   a. The "Nominal fixed charge" refers to the proposed $1 charge for street light and sentinel light, not to the R2 class
   b. The RRRP credit is maintained at $28.50
   c. The range pertains to the proposed 4 Year Phase-In Mitigation plan for all R2 mapped customers – existing R2, F1, F3 and Caledon OH-06. There is no Nominal fixed Charge for R 2
   d. The proposal is to move all Legacy customers identified as Urban directly to the Urban rate class so there is not a range of rates. In the R1 class, there is only the Legacy R1 so a single variable rate. However, in the new R2 class, the Legacy Rate classes mapped-in are F1, F3 and Caledon OH-06 classes which gives rise to the range of mitigated rates.

f. Hydro One assumes that Table 4 is of reference (ii) and not (i) since no Table 4 exists in reference (i). The impacts are for the average customer in each of the existing classes which are being mapped to the new rate class and reflect total impacts.

g. Yes, for an average existing 1,000 kWh R2 customers, the total bill impact at the target rate is 1.1%. For the same customer, the after mitigation impact is 2.1% as provided in the answer to part a. The 9% listed in Exhibit G1, Tab 8, Schedule 1, Table 2 refers to the Caledon OH-01 customer. A mitigation plan is being proposed to be consistent with the other rate Classes being phased-in over 4 years.

h. The proposed Mitigated Rates achieve the class Revenue Requirement every year without an additional shortfall based on the revenue to cost ratios of Exhibit G1, Tab 3, Schedule 1, Table 2. The shortfall will be recorded in the proposed deferral account.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #64 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 8, Schedule 1, Table 1
ii) Exhibit G2, Tab 5, Schedule 1, pages 8-14

Question:

a) With respect to the R2 Class rates, please explain:
- Why there is a range of volumetric rates in Reference (i) but only one volumetric rate in Reference (ii).
- The difference between the range of fixed charges set out in Reference (i) and the range set out in Reference (ii).

b) With respect to Seasonal rates, please explain:
- The difference in the range of fixed charges as between the two references.
- The difference in the range of variable charges as between the two references.

c) With respect to the GSd class, please explain:
- The difference in the range of fixed charges as between the two references.

d) With respect to the GSe class, please explain:
- Why Reference (i) has a single volumetric charges while there are a range of volumetric charges for the metered and unmetered GSe classes in Reference (ii).
- The difference between the range of fixed charges noted in Reference (i) with that noted for metered and unmetered GSe customers in Reference (ii). Note: The $0.35 adder allowance for USL does not account for all of the discrepancies.

e) For those classes where there is range of fixed charges (based on the existing Legacy customer class), please explain:
- Why differing fixed charges are proposed
- How the proposed fixed charges were established

Response

a. The fixed and variable charges presented in Table 1 of Exhibit G1, Tab 8, Schedule 1, comprise both the Legacy and Caledon OH-06 rate classes. The R2 rate schedules in Exhibit G2, Tab 5, Schedule 1, relate only to the Legacy Rate classes while the rates for Caledon OH-06 are presented in Exhibit G2, Tab 18, Schedule 1, page 3.

b. The fixed and variable charges presented in Table 1 of Exhibit G1, Tab 8, Schedule 1, comprise both the Legacy and Caledon OH-07 rate classes. The Seasonal rate schedules in Exhibit G2, Tab 5, Schedule 1, relate only to the Legacy Rate classes while the rates for Caledon OH-07 are presented in Exhibit G2, Tab 18, Schedule 1, page 4.

c. The range listed in Exhibit G1, Tab 8, Schedule 1, Table 1 for GSd is incorrect and should read $38.68 to $207.30.

d. The range listed in Exhibit G1, Tab 8, Schedule 1, Table 1 for GSe is incorrect and should read $34.74 to $203.36. Further, the data for GSe in Table 1 does not include the unmetered customers.

e. The Phase-In mitigation process is applicable to all customer classes which comprise the new rate class. It is not limited to the Acquired customers only and as such, the Legacy rate classes will also have a range of fixed and variable charges. This is consistent with the evidence presented in Exhibit G1, Tab 7, Schedule 1, page 7, line 5 to page 8 line 2.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #65 List 1

Interrogatory

Reference: Exhibit G1, Tab 10, Schedule 1, pages 3 - 5

Question:

a) With reference to page 3 (lines 6-8), based on a weighted average (using energy) what would be the TLF for the Sub-Transmission class?

b) Please provide an illustrative numerical example of the situation described on per page 5, lines 12-18 and how the adjustment would be done in situations where there is no metering at the customer supply point.

c) What is Hydro One Distribution's historical experience with respect to Distribution losses? Please provide values for 2003-2007.

d) Please confirm that total system losses consist of both technical losses and non-technical losses such as theft of power, meter inaccuracies, billing errors, etc.

e) Were the existing loss factors for customer classes other than ST based on technical loss factor considerations only or did they address non-technical losses as well?

f) Please explain why the approach proposed for various ST customers (page 5, lines 1-5) wouldn't unfairly burden other customer classes with all of the non-technical losses. Why hasn't Hydro One proposed an adder to the ST loss factor for non-technical losses as suggested by Kinectrics (G1-10-1, Attachment A, pages 20-21)?

Response

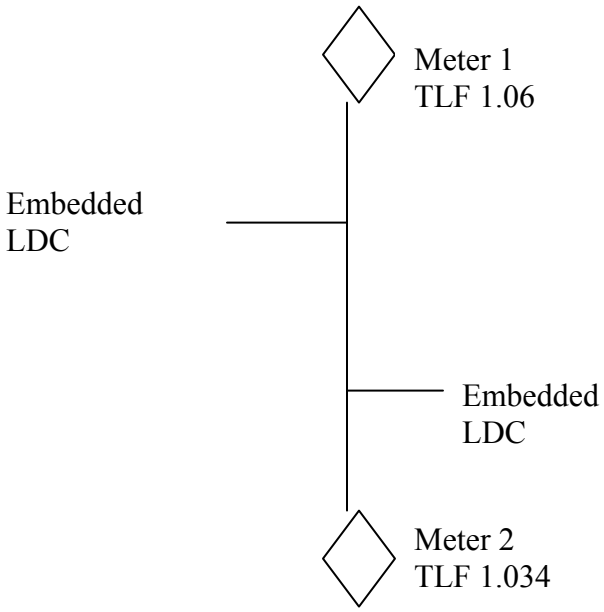
a. Weighting the source classes' TLFs by energy would produce an ST TLF of 1.036, contrasted to the proposed value of 1.034.

b. In the following example, there are 2 meters – meter 1 on the feeder at the station and meter 2 at the end of the feeder where Hydro One Distribution is taking power. An embedded LDC is tapping off from the feeder between the two meters. The current settlement is m1*1.06 - m2*1.034. However, if the settlement is performed as (m1-m2)*1.034, as illustrated below, the loss applied to m1 would be 1.034 instead of 1.06.

Reading in meter 1 =100
Reading in meter 2 =30

Result from method 1
100*1.06-30*1.034=75

Result from method 2
(100-30)*1.034=100*1.034-30*1.034=72



c. Please see Exhibit H, Tab 2, Schedule 3

d. Yes, total system losses consist of both technical losses and non-technical losses

e. The existing loss factors for customer classes other than ST address non-technical losses considerations. The 3.4% loss factor for ST includes both, technical and non-technical losses

f. The approach to technical losses proposed for various ST customers does not unfairly burden other customer classes because the loss factors for other classes do not change as a result of allowing some customers to determine losses based on engineering studies. If ST customers are not being charged properly for total losses, it is Hydro One that absorbs the difference, not other customer classes. The proposed loss factor changes are based on the weighted average of the currently approved loss factors. If

the OEB approves an adder for non-technical losses that should be applied to ST customers that make use of engineering studies to develop their distribution loss factor, the adder should be 10% of technical losses. 10% of technical losses is the adder in the current loss factor to account for non-technical losses (as per Exhibit A, Tab 15, Schedule 3, Attachment A, page 2, Table 2 footnote). Hydro One would work with the IESO to implement this non-technical losses adder for customers making use of the engineering studies approach.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #66 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 2

Preamble: *Section 3.0 outlines the approach used to determine the density weighting factors for lines and transformers. The text states that for lines "customer density weighting factors were developed by calculating for all feeders the number of customers by customer class each feeder and assigning the total distance of feeders to the various customer classes proportionately".*

Question:

a) Please provide a schedule that sets out all of the USOA accounts that are allocated in whole (or in part) based on density weighted allocation factors.

b) With respect to the schedule provided per part (a), please indicate for each USOA account the density factors for each customer class used in weighting customer and/or demand allocators.

c) Please provide more details as to how the density factors for lines were determined, such as:
- For which overhead lines (i.e. voltages) were density factors calculated? Related to this, for which categories of overhead lines (Sub-Transmission, Primary and Secondary) were density factors developed
- It appears that the analysis was done by "feeder". Please describe what the definition of a "feeder" is in this context. Are feeder voltages specific?

d) Please provide an illustrative example of how the Customer density weightings for lines were determined assuming a small number of feeders that represent the cross-section of the line voltages in Hydro One's distribution system with a mix of customer classes connected to each.

e) To what types of transformers are weighting factors applied for purposes of allocation? In contrast, what transformation facilities are allocated without the use of density weighting factors?

f) Was the same definition of feeder (page 2, line 15) used for the development of the transformer weightings?

g) For purposes of the transformer weightings, is the feeder identification used to associate transformers to feeders based on the high or low side voltage of the transformer? Please provide the rationale for the choice.

h) Please confirm that for the Transformer Customer Density weightings the NBV of the transformers on each feeder were assigned to customer classes proportional to the number of customers by class using the feeder. Please provide an illustrative example.

Response

a. The following USoA accounts are allocated with density weights.

1830-3B	Bulk Fixtures - Retail
1830-4B	Primary Fixtures - Retail
1835-3B	Bulk Conductors - Retail
1835-4B	Primary Conductors – Retail
1850-2	Rural Transformers

The resultant Net Fixed Assets [NFA] and Operations & Maintenance [O&M] are thus also impacted because these asset accounts impact the NFA calculation while O&M allocation "piggy-backs" on the relevant asset.

A full listing impacted USoA accounts is contained in Exhibit G2, Tab 1, Schedule 1, Attachment A, E2 TB Allocation Details pages 124 to 134.

b. The density factors per rate class are presented below:

	Lines			**Transformers**	
	Customer	Demand		Customer	Demand
UR	0.19	0.18		0.77	0.75
R1	0.66	0.64		0.93	0.88
R2	1.61	1.42		1.23	1.12
Seasonal	1.20	1.60		0.87	1.28
GSe	1.11	1.15		1.00	1.04
GSd	1.14	1.18		1.05	1.01
UGe	0.24	0.18		1.03	0.79
UGd	0.31	0.30		0.76	0.94
Dgen	1.00	1.00		1.00	1.00
ST	1.00	1.00		1.00	1.00
St Lgt	1.00	1.00		1.00	1.00
Sen Lgt	1.00	1.00		1.00	1.00

c. All lines were included in the analysis to derive density weights. A feeder is a distribution line. Yes, feeders are voltage specific in that they connect from a station.

d. The following is a simplified overview of the density weights derivation.

Connectivity data exists to connect customer by rate class to feeders. The length of the feeder is also known. Based on the share of customer per rate class, a portion of the feeder is allocated to the rate class. This process is done for all over 3,000 feeders and total allocated kms per rate class are determined.

Based on the total allocated feeder kms per rate class, the km/cust metric is derived.

The weights are then determined by weighing the km/cust by total customers as outlined below for each class grouping, (ie. Residential, General Service energy billed, General Service demand billed).

Connectivity Data

	Feeder	Km	Class 1	Class 2	Class 3	Total Class
	1	10	5	20	10	35
	2	20	10	10	20	40
	3	30	15	5	20	40
	4	40	20	5	10	35
A	Totals	100	50	40	60	150

Allocated km

	Feeder	Km	Class 1 km	Class 2 km	Class 3 km
	1	10	1.4	5.7	2.9
	2	20	5.0	5.0	10.0
	3	30	11.3	3.8	15.0
	4	40	22.9	5.7	11.4
B	Total km	100	41	20	39

C=B/A	km/cust		0.81	0.50	0.65
A	Cust	150	50	40	60
D*	**Wts**		**1.22***	**0.76**	**0.98**
E=DxA (Check)	Wted Cust	150	60.8	30.3	58.9

D*= Wts 0.81x150/[0.81 x 50 + 0.5 x 40 + 0.65 x 60]=1.22

e. The transformation assets captured under USoA 1850-2 for the Rural retail customers are density weighted. The small transformation balance that has been isolated to serve the ST class as part of USoA 1850-1 is not density weighted.

f. For the transformation density weights, the feeder length is replaced with connected rural transformation Net Book Value per feeder. The feeder definition is consistent with that for Lines.

g. The association of transformation to feeders does not consider the high or low side connection. Based on Hydro One's Distribution Outage Response Management System, each feeder is listed with attached transformers by size category. For each feeder, the number of transformer per size category is added up and an average net book value per transformer size is used to estimate the net book value of transformation attached per feeder.

h. Yes, for the Transformer Customer Density Weights, the NBV of transformers is allocated to rate classes proportional to the number of customers by class using the feeder. The example presented in Part d with feeder km replaced with feeder NBV would be an illustrative example.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #67 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 5

Question:

a) What is meant by the term "approved Revenue Requirement" (line 12)?

b) What is the value of the Transformer Ownership Allowance included in the Revenue Requirement?

c) With respect to Input Sheet I6, please indicate in which USOA accounts the Transformer Ownership Allowance is included. If more than one account, please indicate the amount included in each account and the basis for the split.

d) Based on the account(s) where the Transformer Ownership Allowance is included, please describe how the cost of the Transformer Ownership Allowance is allocated to customer classes.

e) Please provide a schedule that sets out the amount (total dollars) of the Transformer Ownership Allowance that is received (by way of a rate discount) by each customer class.

f) Please provide the results (i.e. revenue to cost ratios per Output Sheet O1) of an alternative Cost Allocation run where:
- The cost of the transformer ownership allowance is not included in the Allocation.
- The revenues included in the run for each customer class are net of the transformer ownership allowance.

Response

a. The term that should have been used is proposed 2008 revenue requirement

b. Zero. Please see Exhibit H, Tab 12, Schedule 49.

c. It was not included in the Revenue requirement

d. See part c) above

e. The 2006 customer supplied transformation allowance by existing rate class is presented in the following table:

GSd	$ 763,994
DGen	$ 18,408
UGd	$ 145,840
ST	$ 2,931,730
Total	$ 3,859,972

All the customers that in 2006 received transformer ownership allowance and that are going to be included in the new ST class will no longer receive the allowance. One of the criteria of the new ST class is that customers own their transformers. In the Cost Allocation, no transformer costs have been allocated to the ST class.

f. The revenue to cost ratio is unchanged since it has not been included in costs in the Cost Allocation.
If in determining the revenue to cost ratios, revenues are net of the transformer ownership allowance, the revenue to cost ratio for GSd would be 1.02, for DGen it would be 1.59, and for UGd it would be 0.94.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #68 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, pages 5-7

Question:

a) Is the Working Capital associated with USOA 1985 (Sentinel Lights) allocated directly to the Sentinel Light class (page 6, lines 5-7)? If not, why not?

b) Why was a portion of Wholesale Meter costs reclassified to stations with primary below 50 kV (page 6, line 10)?

Response

a. No, the Working Capital associated with Sentinel Lights is not directly allocated to Sentinel Lights. Neither is the Working Capital associated with the other rate classes.

The Working Capital is used to develop the Rate Base which is then used to allocate a variety of costs like Interest and Net Income. The use of the Rate Base allocator is outlined in the Cost Allocation Model sheet E4 TB Allocation Details.

b. Hydro One Distribution has its Wholesale Meters captured under USoA 1815. However, the Cost Allocation Model uses USoA 1820-3 in I4 TB Breakout Sheet to capture Wholesale Meter Assets. This required the re-assignment of the Wholesale Meter Assets from 1815 to 1820 for eventual direct mapping into 1820-3.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #69 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 7, lines 13-16

Question:

a) Please provide an explanation as to what stations (in terms of voltages (high and low side) and customers served) are assigned to each of the five breakout groups for Transformation Station Equipment (page 7, lines 13-16).

b) Please provide a schedule that indicates how these five groups align with the HVDS-high; HVSD-low and Shared LVDS charge categories proposed for the ST class.

c) Are there any assets in this category that are "shared" between ST and Other Retail customers? If yes, into which sub-accounts are they assigned? If not, please reconcile this situation with that presented in RP-2000-0023 (Exhibit E, Tab 2, Schedule 2, page 19) where a portion of the both HVDS and LVDS stations were shared.

d) How were the breakout percentages for Transformer Station Equipment (Account #1815 per Exhibit G2-1-1, Attachment A, page 16) determined?

e) In its RP-2000-0023 Application, Hydro One separated out Regulating Stations and treated them similar to LV lines (see Exhibit E, Tab 2, Schedule 2, page 19). How are Regulating Stations treated in the current Cost Allocation?

f) Please clarify what facilities are included in Account #1815 versus #1820.

g) Please clarify what facilities are included in #1820-2 versus #1820-3. How was the cost split between the two sub-accounts established?

Response

a. Umbrella account:
1815 – Transformer Station Equipment – Normally Primary above 50 kV

Sub-accounts:
1815-1 HVDS – Rural ---- is for all HVDSs which supply no ST customers, plus the non-ST portion of HVDSs shared between ST and non-ST customers
1815-2 HVDS – low LV Specific ---- is for HVDSs which supply solely one ST customer, and whose low voltage side is 12.5 kV or less
1815-3 HVDS – high LV Specific ---- is for HVDSs which supply solely one ST customer, and whose low voltage side is 13.8 kV or more
1815-4 HVDS – low LV Shared ---- is for the ST portion of HVDSs shared between ST and non-ST customers, for HVDSs whose low voltage side is 12.5 kV or less
1815-5 HVDS – high LV Shared ---- is for the ST portion of HVDSs shared between ST and non-ST customers, for HVDSs whose low voltage side is 13.8 kV or more

HVDSs are supplied from either 115 kV or 230 kV.

b. Sub-accounts:
1815-1 HVDS – Rural ---- does not align with any ST rate
1815-2 HVDS – low LV Specific ---- aligns with the HVDS-low ST rate
1815-3 HVDS – high LV Specific ---- aligns with the HVDS-high ST rate
1815-4 HVDS – low LV Shared ---- aligns with the HVDS-low ST rate
1815-5 HVDS – high LV Shared ---- aligns with the HVDS-high ST rate

c. Some assets in the "umbrella" 1815 category are shared between ST and non-ST customers. However, there is no such sharing within any of the five 1815 sub-accounts.

To reconcile this situation with that of the reference to RP-2000-0023:

1815-1 HVDS – Rural
would correspond to the "HVDS – Networks Retail" in RP-2000-0023, except for the asset values associated with some of the customers and their energy that in EB-2007-0681 are ST customers. These ST customer asset values would be in 1815-4 or 1815-5 in EB-2007-0681.

The accounts:
1815-2 HVDS – low LV Specific
1815-3 HVDS – high LV Specific

1815-4 HVDS – low LV Shared
and
1815-5 HVDS – high LV Shared
would correspond to "HVDS – LDCs & Directs" in RP-2000-0023 plus some of the asset values associated with some of the customers and their energy that in EB-2007-0681 are ST customers but in RP-2000-0023 are Retail (non-LDC non-Direct).

Account "1820-2 Distribution Station Equipment – Normally Primary below 50 kV Primary"
would correspond to "LVDS (Networks Specific)" and "LVDS – Shared" in RP-2000-0023. There are no longer any "LVDS (LDC-specific)" in Hydro One's system.

d. Determination of the breakout percentages:
1815-1 HVDS – Rural ---- the remainder, after the other sub-accounts have taken their portions
1815-2 HVDS – low LV Specific ---- consistent with gross asset value of the specific station(s)
1815-3 HVDS – high LV Specific ---- consistent with gross asset value of the specific station(s)
1815-4 HVDS – low LV Shared
and
1815-5 HVDS – high LV Shared ---- the gross asset values of all the shared HVDSs were allocated to ST and non-ST in proportion to the kWh of the two customer groups, Then the percent of the ST portion over the gross asset value of all HVDSs (shared and not shared) was split equally between 1815-4 and 1815-5

e. Regulating stations are included with the ST lines.

f. Account "1815 – Transformer Station Equipment – Normally Primary above 50 kV" includes HVDS equipment, while "1820 – Distribution Station Equipment - Normally Primary below 50 kV" includes LVDS equipment.

g. Account 1820-2 is for LVDS equipment itself, while account 1820-3 is for wholesale meters. The cost split between the two sub-accounts is based on fixed assets.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #70 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 7, lines 18-22
Exhibit G2, Tab 1, Schedule 1, Attachment A, page 16

Question:

a) Please provide a schedule setting out how was Account 1830 (Poles, Towers and Fixtures) broken out into: i) Sub-transmission Bulk Delivery, ii) Primary and iii) Secondary? In describing the approach used please clarify the following:
- The definition of the each of the three breakout groups (i.e., what are the different voltages for the lines carried by each group?
- How the breakout methodology captured any differences in costs of the types of poles and towers used for each of the three groups?

b) What types (e.g., size/class) of Poles/Towers are used for i) Sub-transmission Bulk Delivery, ii) Primary and iii) Secondary facilities? Please provide a schedule that for each of the three groups indicates the number of poles/towers by type.

c) Please provide a schedule that sets out the current replacement cost for each size/class of pole employed by Hydro One Networks per part (b).

d) Based on the results from (b) and (c) please calculate:
- The weighted (by km) average replacement cost of for a Sub-transmission, Primary and Secondary pole/tower.
- A revised percentage split between Sub-transmission, Primary and Secondary using the km associated with each and the average cost per pole as determined in the preceding bullet.

e) The additional Sub-Accounts created for 1830-3 and 1830-4 suggest that Sub-transmission (Bulk) and Primary facilities are used exclusively by either the ST class or Other Classes. A similar observation applies to sub-accounts #1835-3 and #1835-4:
- Please confirm if there are any Sub-transmission or Primary facilities in these accounts that are shared as between the ST customers and the Other customers.
- If yes, how is this accounted for in the cost allocation methodology?
- If no. please reconcile this circumstance with that presented in RP-2000-0023 (Exhibit E, Tab 2, Schedule 2, page 13) where a substantial portion of the then LV Lines were shared.

Response

a. Sub-transmission Bulk Delivery lines are between 44 kV and 13.8 kV inclusive. Primary lines are between 12.5 kV and 4.16 kV inclusive. Secondary lines are under 750 V.

The percentages of 20% Sub-transmission Bulk, 65% Primary and 15% Secondary are proportional to lengths of line for the three groups weighted by the relative unit costs of the three groups. Any differences in the costs of the types of poles or conductor used for each of the three groups was inherent in the relative unit costs.

Estimates were obtained for the relative construction costs of different types of line (depending on whether the line is on road allowance or not, the number of phases and some inherent broad voltage-related aspects). The estimates included poles, conductor, forestry and other requirements. The relative cost estimates were blended to estimate the relative unit cost for each of Sub-transmission Bulk, Primary and Secondary (1, 0.78 and 0.40 respectively). These relative unit costs weighted the length of line for Sub-transmission Bulk, Primary and Secondary (25k km, 94.4k km and 47.8k km respectively). Multiplying the relative unit cost by line length produced the splits of 20%, 65% and 15% for Sub-transmission Bulk, Primary and Secondary respectively.

b. The size and class of poles are not determined by their utilization as sub-transmission, primary or secondary, but rather by the strength and clearance requirements set out as per engineering analysis. Both size and class will be impacted by the length of distances between poles, size of conductors, other utilities on the pole through joint use, equipment requirements on the pole and various clearances required as per standards.

The size and class and poles would typically range from 35' Class 4 to 65' Class 2 poles, although larger and stronger poles are required for individual circumstances. Due to the general characteristics of sub-transmission lines (e.g., larger conductor and in some cases under-built with primary) the poles are generally somewhat larger.

Hydro One does not have the number of poles broken down by sub-transmission, primary and secondary.

c. Hydro One does not have the replacement cost for poles broken down by sub-transmission, primary or secondary. Replacement costs could vary from $4,500 to over $10,000 depending on factors such as ground conditions, accessibility to the pole location, and work equipment required.

d. Lack of data for parts "b" and "c" prevents calculations following the exact process requested. However, the calculation of the percentages used to break down accounts

1830 and 1835 was analogous to the combination of that requested in this question regarding poles plus that requested in Exhibit H, Tab 12, Schedule 71 part c) regarding conductor. Please see the response to part a) above.

e. The created sub-accounts for Bulk and Primary are shared between by all the rate classes including ST. These Bulk and Primary sub-accounts are then further delineated to isolate the ST component from the Retail Class component. This was accomplished by creating another level of sub-account as can been seen in Exhibit G2, Tab 1, Schedule 1, Attachment A, page 16 for USoA 1830 which is initially decomposed into Bulk-Primary-Secondary via sub-accounts 1830-3, 1830-4 and 1830-5, respectively. Then the Bulk and Primary sub-accounts are further decomposed into their ST and their Retail components using additional sub-accounts 1830-3A and 1830-3B.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #71 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 7, lines 24-28

Question:

a) Please provide a schedule that sets out how Account 1835 (Overhead Conductors and Devices) broken out into: i) Sub-transmission Bulk Delivery, ii) Primary and iii) Secondary? In describing the approach used please clarify how the breakout methodology captured any differences in cost per km for the conductor/wire in each of the three groups.

b) What types of conductor are used in each of the three groups? Please provide a schedule that sets out for each of the three groups:
- the different types of conductor used,
- the km of line by type of conductor, and
- the replacement cost per km for each.

c) Base on the results from (b) please calculate:
- The weighted (by km) average replacement cost of for a km of Sub-transmission, Primary and Secondary conductor.
- A revised percentage split between Sub-transmission, Primary and Secondary using the km associated with each and the average cost per km as determined in the preceding bullet.

d) Where does Hydro One include the facilities that would normally be reported as Services (Account 1855)?

Response

a. The percentages of 20% Sub-transmission Bulk, 65% Primary and 15% Secondary are proportional to lengths of line for the three groups weighted by the relative unit costs of the three groups. Any differences in the costs of the types of conductors used for each of the three groups was inherent in the relative unit costs. Please see Exhibit H, Tab 12, Schedule 70 part a).

b. A variety of conductors is used in the three groups. Common sizes are 336 kcmil and 1/0 ACSR, but other sizes are used also. Hydro One does not have the types, distances, or costs of conductor broken down by sub-transmission, primary and secondary.

c. Lack of data for part "b" prevents calculations following the exact process requested. However, the calculation of the percentages used to break down accounts 1835 and 1830 was analogous to the combination of that requested in this question regarding conductor plus that requested in Exhibit H, Tab 12, Schedule 70, part d) regarding poles. Please see Exhibit H, Tab 12, Schedule 70, part a).

d. Hydro One Distribution has no costs charged to USoA 1855. Historically, there was never a business need for Hydro One Distribution to differentiate between primary and secondary systems. Consequently, as processes were streamlined / automated, no differentiation was made between primary and secondary systems. All costs are recorded within our fixed assets system as conductor in USoA 1835.

For overhead services, Hydro One Distribution's cost is the cost incurred from the primary tap point to the mast head, if the distance is 30 metres or less. The customer is responsible for any cost beyond the 30 metres. Accordingly, Hydro One Distribution would at most record in account 1855 up to 30 metres of secondary conductor per connection and the associated installation costs.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #72 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1

Question:

a) Please provide the results of an alternative 2008 Cost Allocation Run where Accounts #1830 and #1835 are split between Sub-transmission; Primary and Secondary using the percentages derived in response to Questions #69 d) and #70 c).

Response

Note:
As a result of two VECC interrogatories both being labeled as # 38, the 2nd question #38 has been addresses in Exhibit H, Tab 12, Schedule 39. Subsequent interrogatories have been numbered sequentially. As such, the reference to question #69 d and #70 C are referred to in the response as Exhibit H, Tab 12, Schedule 70 d and Exhibit H, Tab 12, Schedule 71 c, respectively.

a. Based on response to Exhibit H, Tab 12, Schedule 70, part d and Exhibit H, Tab 12, Schedule 71, part c, new decomposition shares are not available so the request of an alternative Cost Allocation run cannot be provided.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #73 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 8, lines 2-3

Question:

a) How was account 1850 (Line Transformers) broken out between LV and Other End Use Customers? Please confirm whether LV is equivalent to ST customers. If not please, explain.

Response

a. The Line Transformers Asset account USoA 1850 was decomposed into the LV and Retail components using 2006 fixed assets information. Further, the LV and ST terms are used inter-changeably and they are equivalent.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #74 List 1

Interrogatory

Reference: i) Exhibit G2, Tab 1, Schedule 1, page 10
ii) Exhibit G2-1-1, Attachment A, pages 35-36

Question:

a) Please explain why the alternative allocation of Miscellaneous External Revenues proposed by Hydro One (Reference (i), lines 20-21 and Reference (ii), page 36) is considered the "proper allocation.

b) Please define each of the allocation factors used in this alternative allocation explain why it is more appropriate.

c) Please explain how the individual class values for the following rows on page 36 were calculated:
- Allocated Costs based on Alloc External Revenues
- CREV+Unique Allocation of Miscellaneous Revenues

Please provide a numerical example of each using the UR class.

d) Please explain how the "Revenue to Cost Ratio – External Unique Allocation" was determined and provide a numerical example using the UR class.

Response

a. The alternative allocation used by Hydro One is considered the proper allocation because information exists for the composition of the external revenue balances, which have been analyzed separately, and more specific allocators have been chosen. Refer to Exhibit H, Tab 1, Schedule 153

The default allocation of external revenues by the Cost Allocation Model for the large Late Payment USoA 4225 and Misc Service Revenue USoA 4235 are Late Payment Historical Average [LPHA] and Customer Weighted Number Bills [CWNB], respectively. Hydro One Distribution has a large component of Sentinel Light rental revenues captured within USoA 4235 which should be allocated directly to Sentinel Lights and not all classes based on the default allocator of CWNB

b. The details of the External revenue from Exhibit H, Tab 1, Schedule 153:

Category	Allocation	Rationale
Sentinel Light	Direct Allocation	Proper
Late Payment	LPHA	Best available
Collections	# connections	Best available
New Connects / Upgrades	# connections	Best available
Joint Use	O&M	Generic
Other	O&M	Generic

c. Refer to Exhibit H, Tab 1, Schedule 153

The details based on UR rate class will be used to explain the following terms:

Allocated Cost Based on Alloc External Revenues:

Cost Model Allocated Cost	$66,965,969
Less Model External Revenue	-$4,835,012
Plus Unique Allocated External Revenue	$3,823,728
Total	$65,954,685

CREV+Unique Allocation of Miscellaneous Revenue

Customer Revenue [CREV]	$53,878,006
Unique Allocated External Revenue	$3,823,728
Total	$57,701,734

d. Refer to response to Exhibit H, Tab 1, Schedule 153

The details based on UR rate class will be used to explain the following terms:

Rev to Cost Ratio – External Unique Allocation

Rev = CREV+Unique Allocation of Miscellaneous Revenue = $57,701,735
Cost= Allocated Cost Based on Alloc External Revenues = $65,954,685

Rev/Cost = 0.875

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #75 List 1

Interrogatory

Reference: i) Exhibit G2-1-1, Attachment A, pages 35 and 47
ii) OEB RP-2005-0317, Section 10.3

Question:

a) Please confirm that Hydro One followed the Board's direction regarding the allocation of Administrative and General Costs.

b) Please breakdown Hydro One's A&G Expenses ($122,080,727) between:
- Property Insurance
- Community Safety Programs
- Remaining A&G Expense

c) Please indicate where in Exhibit G2-1-1, Attachment A the allocation of each of these components of A&G Expenses to customer classes is shown.

d) Unless fully set out in Exhibit G2-1-1, Attachment A, please provide a schedule that show the allocation of each of the components described in part (b) to customer classes including the definition and values for the allocator used in each case.

e) With respect to Reference (i), page 35, please provide a schedule that shows the costs directly allocated to each customer class (Total = $7,169,250) by USOA account.

f) Please confirm that the O&M costs directly allocated to customer classes were included in the Allocation Base used to pro-rate the "Remaining A&G" costs from part (b) above to customer classes. If this is not the case, please provide an alternate Cost Allocation Run where remaining A&G costs are pro-rated to customer classes based on the O&M costs allocated to classes (including directly allocated O&M).

g) If the response to part (f) is confirmed in the positive, please reconcile the following:
- The General and Administration costs allocated to UR represent 31.8% of Distribution and Customer Related Expenses assigned to the Class.
- The General and Administration costs allocated to ST represent 23.5% of Distribution, Customer-Related and Directly Allocated expenses assigned to the Class – a significantly lower percentage.

Response

a. The Administrative and General Costs are allocated based on the defaults per the Cost Allocation Model per E4 TB Allocation Details.

b. The Cost Allocation Model summed General and Administration total of $1,222,080,727 is decomposed for the two accounts as requested.
Full details by USoA can be found in Exhibit H, Tab 12, Schedule 55

- Property Insurance USoA 5635 $2,715,447
- Community Safety Programs USoA 5420 $864,318

c. The allocation for the USoA accounts are outlined in the Cost Allocation Model sheet E4 TB Allocation Details which is provided in Exhibit G2, Tab 1, Exhibit 1, Attachment A on page 125 to 134. The requested USoA of 5420 and 5635 are allocated based on the defaults of "NFA ECC" [Net Fixed Assets Excluding Contributed Capital] found on page 133.

d. All the General and Administration related accounts are contained in the Cost Allocation Model O4 Summary by Class and Accounts [page 50 of Exhibit G2, Tab 1, Schedule 1, Attachment A]. They can be identified with the O1 Grouping flag of using "ad". These "ad" USoA accounts are allocated to the rate classes based on the default allocators in the Cost Allocation Model E4 TB Allocation Details[Attachment page 125]. Finally, all the allocator values can be found it Cost Allocation Model E2 Allocators [Attachment page 118].

e. The requested details by USoA account and Rate Class can be found in Exhibit G2, Tab 1, Schedule 1, Attachment A Cost Allocation Model I9 Direct Allocation page 31 to 34.

f. No, only the non-directly allocated O&M costs are used to develop the allocator for the other O&M accounts. This is as per the Cost Allocation Model provided by the Board, which does not develop its generic O&M allocator based on total costs including those directly allocated using I9 Direct Allocation sheet. The request to develop a new O&M allocator inclusive of these directly allocated costs would require extensive changes in the model that cannot be accomplished within the response time frame.

g. Not applicable based on response to Part f above.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #76 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, pages 11-12

Question:

a) Exhibit G2-1-1, Attachment A does not appear to include Output Sheet 2.1 as referenced on pages 11, line 10 – please provide.

b) Exhibit G2-1-1, Attachment A does not appear to include Output Sheets 3.1 or 3.2, referenced on page 12, lines 4-12 – please provide

Response

Hydro One Distribution did not use the Cost Allocation Model to set its Customer Supplied Transformation Loss Allowance [CSTA] but adopted the currently OEB approved value of $0.60 per kW. Thus, the related model tabs were not provided as part of Exhibit G2, Tab 1, Schedule 1, Attachment A.

a. Request for Output 2.1 is attached.

b. Request for Output 3.1 is attached.

Line Transformers Demand Unit Cost for PLCC Adjustment to Customer Related Cost

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Depreciation on Acct 1850 Line Transformers	$11,891,561	$0	$0	$5,715	$0	$1,798,226	$7,560,057	$383,044	$0	$0	$35,675	$292,072	$1,816,772
Depreciation on General Plant Assigned to Line Transformers	$4,559,366	$0	$0	$2,222	$0	$699,689	$2,888,074	$149,577	$0	$0	$13,339	$114,605	$691,861
Acct 5035 - Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5055 - Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5160 - Maintenance of Line Transformers	$1,218,011	$0	$0	$585	$0	$184,186	$774,350	$39,234	$0	$0	$3,654	$29,916	$186,086
Allocation of General Expenses	$1,807,337	$0	$0	$869	$0	$273,303	$1,149,014	$58,217	$0	$0	$5,422	$44,390	$276,122
Admin and General Assigned to Line Transformers	$408,033	$0	$0	$187	$0	$59,197	$260,425	$12,942	$0	$0	$1,199	$9,597	$64,486
PILs on Line Transformers	$4,335,221	$0	$0	$2,084	$0	$655,566	$2,756,116	$139,644	$0	$0	$13,006	$106,478	$662,327
Debt Return on Line Transformers	$12,849,906	$0	$0	$6,176	$0	$1,943,146	$8,169,325	$413,913	$0	$0	$38,550	$315,610	$1,963,186
Equity Return on Line Transformers	$13,100,847	$0	$0	$6,297	$0	$1,981,093	$8,328,861	$421,997	$0	$0	$39,303	$321,773	$2,001,524
Total	$33,719,356	$0	$0	$24,135	$0	$7,594,407	$31,886,222	$1,618,567	$0	$0	$150,147	$1,234,442	$7,662,364
Line Tranformer NCP	2,807,466	0	0	1,204	0	409,500	1,762,586	90,608	0	0	0	87,373	456,195
PLCC Amount	11,880,449	1,251,313	3,949,134	4,525,230	557,844	1,202,860	86,985	68,955	31,464	79	0	185,761	20,824
Adjustment to Customer Related Cost for PLCC	**$12,008,115**	**$0**	**$0**	**$24,135**	**$0**	**$7,594,407**	**$1,573,607**	**$1,231,761**	**$0**	**$0**	**$0**	**$1,234,442**	**$349,763**
General Plant - Gross Assets	$737,348,954	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
General Plant - Accumulated Depreciation	($405,157,678)	($23,045,827)	($85,373,130)	($139,181,704)	($30,049,079)	($41,406,864)	($47,817,777)	($3,530,466)	($12,960,668)	($23,106)	($9,981,598)	($3,572,444)	($8,215,016)
General Plant - Net Fixed Assets	$332,191,276	$19,239,415	$71,272,299	$116,193,469	$25,085,960	$34,567,813	$39,919,854	$2,947,350	$4,772,300	$19,290	$8,332,967	$2,982,394	$6,858,166
General Plant - Depreciation	$53,851,648	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701
Total Net Fixed Assets Excluding General Plant	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958
Total Administration and General Expense	$122,080,727	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
Total O&M	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865
Line Transformer Rate Base													
Acct 1850 - Line Transformers - Gross Assets	$489,178,757	$0	$0	$235,113	$0	$73,972,976	$310,995,284	$15,757,133	$0	$0	$1,467,536	$12,014,848	$74,735,867
Line Transformers - Accumulated Depreciation	($164,401,256)	$0	$0	($79,016)	$0	($24,860,544)	($104,518,061)	($5,295,595)	$0	$0	($493,204)	($4,037,902)	($25,116,934)
Line Transformers - Net Fixed Assets	$324,777,500	$0	$0	$156,097	$0	$49,112,432	$206,477,222	$10,461,538	$0	$0	$974,333	$7,976,945	$49,618,933
General Plant Assigned to Line Transformers - NFA	$28,026,218	$0	$0	$13,657	$0	$4,300,954	$17,752,862	$919,442	$0	$0	$81,995	$704,470	$4,252,838
Line Transformer Net Fixed Assets Including General Plant	$352,803,718	$0	$0	$169,754	$0	$53,413,386	$224,230,085	$11,380,980	$0	$0	$1,056,327	$8,681,415	$53,871,771
General Expenses													
Acct 5005 - Operation Supervision and Engineering	$1,009,836	$32,432	$171,741	$330,305	$27,727	$126,462	$219,736	$13,698	$1,405	$36	$37,543	$12,440	$36,310
Acct 5010 - Load Dispatching	$384,019	$12,333	$65,310	$125,608	$10,544	$48,091	$83,561	$5,209	$534	$14	$14,277	$4,731	$13,808
Acct 5085 - Miscellaneous Distribution Expense	$5,048,474	$162,137	$858,586	$1,651,292	$138,617	$632,223	$1,098,529	$68,481	$7,024	$178	$187,690	$62,193	$181,523
Acct 5105 - Maintenance Supervision and Engineering	$5,088,435	$163,420	$865,382	$1,664,363	$139,714	$637,228	$1,107,224	$69,023	$7,080	$180	$189,175	$62,685	$182,960
Total	$11,530,764	$370,322	$1,961,019	$3,771,568	$316,603	$1,444,005	$2,509,050	$156,412	$16,044	$407	$428,685	$142,050	$414,601
Acct 1850 - Line Transformers - Gross Assets	$489,178,757	$0	$0	$235,113	$0	$73,972,976	$310,995,284	$15,757,133	$0	$0	$1,467,536	$12,014,848	$74,735,867
Acct 1815 - 1855	$3,120,947,897	$100,232,259	$530,774,596	$1,020,822,743	$85,692,591	$390,838,196	$679,106,396	$42,334,910	$4,342,495	$110,145	$116,029,025	$38,447,545	$112,216,995

Filed: April 4, 2008
Exhibit H
Tab 12
Schedule 76
Attachment A
Page 2 of 2

Line Transformers Unit Cost

Hydro One Distribution: 12 Rate Classes

ALLOCATION BY RATE CLASSIFICATION		1	2	3	4	5	6	7	8	12	13	14	15
Description	**Total**	**UR**	**R1**	**R2**	**Seasonal**	**GSe**	**GSd**	**St Lgt**	**Sen Lgt**	**Dgen**	**ST**	**UGe**	**UGd**
Depreciation on Acct 1850 Line Transformers	$31,211,446	$2,042,745	$5,746,187	$7,385,208	$2,232,688	$3,386,716	$7,681,050	$474,530	$59,317	$526	$93,634	$292,072	$1,816,772
Depreciation on General Plant Assigned to Line Transformers	$12,204,553	$804,515	$2,247,889	$2,870,912	$870,409	$1,317,769	$2,934,296	$185,302	$131,790	$194	$35,011	$114,605	$691,861
Acct 5035 - Overhead Distribution Transformers- Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5055 - Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Acct 5160 - Maintenance of Line Transformers	$3,196,880	$209,231	$588,562	$756,441	$228,686	$346,890	$786,743	$48,604	$6,076	$54	$9,591	$29,916	$186,086
Allocation of General Expenses	$5,631,378	$413,681	$1,115,790	$1,404,187	$474,657	$606,425	$1,182,359	$80,019	$11,880	$94	$14,893	$49,042	$278,352
Admin and General Assigned to Line Transformers	$1,040,675	$66,613	$187,864	$241,653	$73,221	$111,490	$264,593	$16,033	$1,962	$17	$3,147	$9,597	$64,486
PILs on Line Transformers	$11,378,532	$744,709	$2,094,846	$2,692,372	$813,955	$1,234,671	$2,800,225	$172,996	$21,625	$192	$34,136	$106,478	$662,327
Debt Return on Line Transformers	$33,726,788	$2,207,371	$6,209,275	$7,980,385	$2,412,621	$3,659,653	$8,300,069	$512,772	$64,097	$569	$101,180	$315,610	$1,963,186
Equity Return on Line Transformers	$34,385,425	$2,250,478	$6,330,533	$8,136,231	$2,459,736	$3,731,121	$8,462,158	$522,786	$65,349	$580	$103,156	$321,773	$2,001,524
Less: Transformer Ownership Allowance Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	$132,775,678	$8,739,342	$24,520,947	$31,467,390	$9,565,972	$14,394,735	$32,411,494	$2,013,041	$362,095	$2,227	$394,748	$1,239,093	$7,664,594
Billed kW without Line Transformer Allowance		0	96	68,268	0	512,108	9,746,122	0	0	18,163	38,135,708	69,464	1,960,229
Billed kWh without Line Transformer Allowance		1,494,185,912	4,407,443,581	5,624,484,001	706,724,087	2,299,316,442	2,781,257,622	120,597,533	22,417,163	1,613,204	17,009,435,895	424,162,641	736,245,155
Line Transformation Unit Cost ($/kW)		**$0.0000**	**$254,842.7567**	**$460.9376**	**$0.0000**	**$28.1088**	**$3.3256**	**$0.0000**	**$0.0000**	**$0.1226**	**$0.0104**	**$17.8380**	**$3.9101**
Line Transformation Unit Cost ($/kWh)		**$0.0058**	**$0.0056**	**$0.0056**	**$0.0135**	**$0.0063**	**$0.0117**	**$0.0167**	**$0.0162**	**$0.0014**	**$0.0000**	**$0.0029**	**$0.0104**
General Plant - Gross Assets	$737,348,954	$42,285,241	$156,645,429	$255,375,173	$55,135,038	$75,974,676	$87,737,631	$6,477,816	$17,732,968	$42,396	$18,314,565	$6,554,838	$15,073,182
General Plant - Accumulated Depreciation	($405,157,678)	($23,045,827)	($85,373,130)	($139,181,704)	($30,049,079)	($41,406,864)	($47,817,777)	($3,530,466)	($12,960,668)	($23,106)	($9,981,598)	($3,572,444)	($8,215,016)
General Plant - Net Fixed Assets	$332,191,276	$19,239,415	$71,272,299	$116,193,469	$25,085,960	$34,567,813	$39,919,854	$2,947,350	$4,772,300	$19,290	$8,332,967	$2,982,394	$6,858,166
General Plant - Depreciation	$53,851,648	$3,129,910	$11,594,733	$18,902,607	$4,081,039	$5,623,567	$6,494,249	$479,481	$586,414	$3,138	$1,355,625	$485,182	$1,115,701
Total Net Fixed Assets Excluding General Plant	$3,753,292,682	$217,049,574	$809,492,211	$1,328,041,485	$285,905,452	$394,728,573	$464,293,609	$33,535,359	$7,208,513	$232,026	$99,019,286	$33,770,633	$80,015,958
Total Administration and General Expense	$122,080,727	$8,175,774	$29,160,678	$47,082,017	$9,807,237	$12,800,842	$9,184,009	$799,545	$221,038	$6,691	$2,444,240	$1,128,977	$1,269,678
Total O&M	$379,945,270	$25,680,258	$91,357,822	$147,379,654	$30,630,509	$39,828,568	$27,307,859	$2,423,859	$684,638	$20,673	$7,448,318	$3,519,246	$3,663,865
Line Transformer Rate Base													
Acct 1850 - Line Transformers - Gross Assets	$1,283,933,745	$84,031,654	$236,378,793	$303,802,601	$91,845,247	$139,318,101	$315,972,536	$19,520,547	$2,440,092	$21,657	$3,851,801	$12,014,848	$74,735,867
Line Transformers - Accumulated Depreciation	($431,499,360)	($28,241,025)	($79,441,247)	($102,100,773)	($30,866,986)	($46,821,475)	($106,190,797)	($6,560,388)	($820,057)	($7,278)	($1,294,498)	($4,037,902)	($25,116,934)
Line Transformers - Net Fixed Assets	$852,434,384	$55,790,629	$156,937,546	$201,701,828	$60,978,261	$92,496,627	$209,781,740	$12,960,159	$1,620,036	$14,378	$2,557,303	$7,976,945	$49,618,933
General Plant Assigned to Line Transformers - NFA	$75,283,248	$4,945,317	$13,817,674	$17,647,367	$5,350,364	$8,100,265	$18,036,984	$1,139,040	$1,072,523	$1,195	$215,210	$704,470	$4,252,838
Line Transformer Net Fixed Assets Including General Plant	$927,717,632	$60,735,947	$170,755,220	$219,349,194	$66,328,625	$100,596,892	$227,818,724	$14,099,199	$2,692,559	$15,574	$2,772,513	$8,681,415	$53,871,771
General Expenses													
Acct 5005 - Operation Supervision and Engineering	$2,234,150	$129,747	$495,243	$832,362	$193,943	$231,849	$228,422	$19,477	$5,107	$64	$43,329	$17,402	$37,206
Acct 5010 - Load Dispatching	$849,600	$49,340	$188,330	$316,530	$73,752	$88,167	$86,864	$7,407	$1,942	$24	$16,477	$6,617	$14,149
Acct 5085 - Miscellaneous Distribution Expense	$11,169,190	$648,643	$2,475,868	$4,161,231	$969,578	$1,159,082	$1,141,952	$97,371	$25,534	$319	$216,614	$86,996	$186,004
Acct 5105 - Maintenance Supervision and Engineering	$11,257,600	$653,778	$2,495,466	$4,194,169	$977,253	$1,168,257	$1,150,991	$98,141	$25,736	$321	$218,329	$87,684	$187,476
Total	$25,510,540	$1,481,508	$5,654,908	$9,504,292	$2,214,526	$2,647,354	$2,608,229	$222,395	$58,319	$728	$494,748	$198,699	$424,834
Acct 1850 - Line Transformers - Gross Assets	$1,283,933,745	$84,031,654	$236,378,793	$303,802,601	$91,845,247	$139,318,101	$315,972,536	$19,520,547	$2,440,092	$21,657	$3,851,801	$12,014,848	$74,735,867
Acct 1815 - 1855	$5,646,054,341	$300,941,041	$1,197,985,783	$2,056,299,879	$428,506,279	$608,194,042	$697,020,553	$54,253,159	$11,978,422	$168,122	$127,961,768	$48,679,874	$114,065,420

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #77 List 1

Interrogatory

Reference: Exhibit G2-1-1, Attachment B, pages 6-8

Question:

i. With reference to pages 6-7, why if there are over 25,000 5 kVA transformers on Hydro One's system are no costs available for this type of transformer?

ii. Why was 7.2 kV selected as the appropriate high-side voltage (per page 8)?

iii. Using the extrapolation technique described on page 7, what is the estimated replacement cost of a 5 kVA 1-phase overhead transformer with a high-side voltage of 7.2 kV?

iv. Please confirm that the PLCC associated with a minimum system based on a 5 kVA transformer would be roughly 2,000 watts per customer.

v. Please clarify what classes of customers are included in the 1,165,092 customer count.

Response

(i) Hydro One no longer installs this type of transformers, therefore, replacement cost for this type of transformer is not available.

(ii) The 10 kVA 1-phase overhead transformer, with high-side voltage of 7.2 kV, was the least-cost transformer.

(iii) The average cost of one 5 kVA 1-phase overhead transformer would be $1,426. The least-cost 5 kVA overhead transformer could vary somewhat from this average cost. The average cost is not specific as to high-side voltage.

(iv) The Transformer PLCC associated with a minimum system based on 5 kVA 1-phase overhead transformer would be 1,550 watts per customer.

(v) All customer classes are included in the customer count

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #78 List 1

Interrogatory

Reference: Exhibit G2-1-1, Attachment B, pages 9-13

Question:

a) Please explain the basis for Hydro One's estimate that 65% of historical distribution costs (for conductors) are associated with Primary facilities. Similarly, please explain the basis for the 15% attributed to Secondary facilities.

b) If the basis of the estimates (per part (a)) is distance, please confirm that this does not account for the fact the cost of conductors varies by voltage capability.

c) For the Primary and Secondary components of Hydro One's distribution system, please indicate the dominant types of conductor used (based on km) and the km associated with each. If the km are not available, just indicate the types of conductor used predominantly of each "component".

d) What is the current standard cost for 1 km of each type of line identified in response to part (c) – using the same costing approach as outlined at the bottom of page 10?

e) Based on a weighted average or simply using the most predominant types of conductor employed please determine a Minimum System ratio for Primary facilities using:
- The per km cost from part (d) and
- The $9,109 / km cost for the Minimum Component.

f) Where in Hydro One's USOA accounts are the costs of service drops provided to customers at voltages greater than 750V included? How are the costs of these facilities allocated to customers?

g) Please provide examples of where the accepted practice is to split Secondary facilities (not Services) using a 95% ratio for the Minimum System.

h) Since different customers use the Primary and Secondary Systems, why wasn't a separate minimum system ratio established and applied to each?

Response

a. The percentages of 20% Sub-transmission Bulk, 65% Primary and 15% Secondary are proportional to lengths of line for the three groups weighted by the relative unit costs of the three groups.

b. The basis for the estimates, as described in the response to part a), does include a weighting of relative cost of line between groups (Primary vs. Secondary).

c. For the Primary System, the minimum component is based on #2 ASCR two-wire system (one conductor and one neutral). Other conductor materials include #2 Triplex, 266.8 buss wire and 266.8 pre-spun buss wire.

d. For #2 Triplex, the cost is estimated to be approximately $21,000 per km.
For 266.8 buss wire, the cost is estimated to be approximately $31,000 per km.
For 266.8 pre-spun buss wire, the cost is estimated to be approximately $24,000 per km.

e. In the Minimum System Study, the Primary System Minimum System ratio was 45.50%. Detailed information on the composition of the Primary system based on km of each material was not available, and a precise answer is not possible, but a range can be provided. If the Primary system were exclusively 266.8 buss wire (the costliest component identified above), the Primary System Minimum System ratio would be 29.3%, which represents the lowest value possible for the Primary System Minimum System ratio.

If the Primary system were 50% by length #2 ASCR (the Minimum Component) and 50% #2 Triplex, the Primary System Minimum System ratio would be 60.5%.
These are hypothetical numbers that are intended to show a range and not to provide a definitive answer.

f. The cost of service drops at voltages greater than 750 V would be in
1835 – Overhead Conductors and Devices
1845 – Underground Conductors and Devices 1830 – Poles, Towers and Fixtures
1840 – Underground Conduit

These facilities would be allocated to customers in the same manner as the above accounts.

g. The Secondary / Services system comprises conductors operating at voltages under 750 kV and is primarily service drops. The material and length, and therefore cost, of service drops vary based on the customers' requirements, and service drops are typically classified as 100% customer-related; that is, the minimum component is

100%. This was the method applied in a recent cost of service study performed for Duquesne Light Company, and is also consistent with the Electric Utility Cost Allocation Manual, January 1992, National Association of Regulatory Utility Commissioners, page 96.
The Secondary / Services Minimum System Ratio was determined to be 95% to reflect that a small portion of the system is not service drops, and would have a minimum system ratio of less than 100%. A precise breakdown between Secondary and Services was not available, therefore a more precise ratio could not be determined.

h. See response to part g) above.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #79 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1

Question:

a) Please provide the results of an alternative 2008 Cost Allocation run where:
- Accounts #1830 and #1835 are split between Sub-transmission, Primary and Secondary as per Questions #69 d) and #70 c).
- The minimum system and PLCC for Line Transformers is based on a 5 kVA transformer per Question #76.
- A separate minimum system percentage is used for Primary and Secondary conductors
- The minimum system percentage for Secondary conductors is 95%.
- The minimum system percentage for Primary conductors based on the results of Question #77, part (e) above.

Response

Please see Note in Exhibit H, Tab 12, Schedule 72 with respect to referencing VECC questions numbers greater than #38.

A Cost Allocation Model scenario run was performed with the following requested model input changes:

1. New Bulk-Primary-Secondary shares per Exhibit H, Tab 12, Schedule 70, part (d) and Exhibit H, Tab 12, Exhibit 70, Part (c) but based on the response to Exhibit H, Tab 12, Schedule 72, - new shares are not available.
2. PLCC for transformers of 1,550 kW as per Exhibit H, Tab 12, Schedule 77, part (iv)
3. Different Minimum System weights for Primary and Secondary Lines based on the new Minimum System Study results with 45.5% and 95%, respectively with a weighted average of 54.8%
4. Minimum System results based on Exhibit H, Tab 12, Schedule 78, part (e) which results in a range of 29.3% to 60.5% for Primary conductors. This is satisfied by the results of Item 3.

From the above analysis, the new scenario run is based on a PLCC level of 1,550 kWs for transformers and a Minimum System split of 45.5% and 95% for Primary versus Secondary Lines, respectively. The resultant rate class Revenue-to-Cost Ratios are presented in the table below with comparison to the filed ratios of Exhibit G2, Tab 1, Schedule 1, Attachment A, pages 35-36.

Revenue-to-Cost Ratio Results		
Rate Class	As Filed	PLCC of 1,550 kWs Primary Lines @ 45.5% Secondary Lines @ 95%
UR	0.87	0.84
R1	0.82	0.79
R2	1.04	1.00
Seasonal	0.92	0.90
GSe	1.08	1.10
GSd	1.02	1.23
St Lgt	0.60	0.69
Sen Lgt	0.62	0.61
Dgen	1.63	1.64
ST	2.35	2.34
UGe	1.29	1.42
UGd	0.95	1.32

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #80 List 1

Interrogatory

Reference: i) Exhibit G2, Tab 2, Schedule 1
ii) Exhibit G1, Tab 8, Schedule 21

Question:

a) With respect to Table 6 in Reference (i), please explain how the LDC year 1 energy rate of $0.024/kWh is determined.

b) Table 6 of Reference (i) suggests that all acquired LDC residential customers in a particular customer class will have the same energy rate (e.g., for R1 it is $0.0271 / kWh). However, Table 1 in Reference (ii) shows different mitigated energy rates for the different Acquired LDCs whose residential customers are in the same customer class. Please reconcile.

c) With respect to Reference (ii), pages 1, please explain how "average total bill impacts" (per lines 19-20) are determined.

d) Please clarify how the proposed rates for each customer class in each Acquired Utility were determined. Please confirm if the following understanding is correct and, if not, make any corrections required:
- The proposed service charge is determined using the procedure illustrated in Table 6 of Reference (i).
- The proposed energy rate was set at the target energy rate – unless the average total bill impact exceeded 10%.
- If the average total bill impact exceeded 10%, then the energy rates was reduced so that the impact would be below 10%. (Note: Please clarify what is meant by below 10%, e.g., 9.99%)

e) With respect to Reference (ii), page 1, please provide a schedule that for each customer class lists all of the Acquired Utilities with customers in that class and for each Acquired Utility indicates the shortfall in revenues due to the proposed mitigation measure (per lines 24-26). What is the resulting total shortfall by customer class.

f) Please describe more fully the recovery plan for this shortfall (per Reference (ii), pages 1, line 25 to page 2, line 2). In particular please provide more details regarding the period of time over which the shortfall will be recovered and what is meant by the term "same group" (per page 2, line 1).

g) Please confirm that the impact ranges shown in Tables 8-10 are for the average customer in the class using the Target Rates.

h) Please provide a set of tables similar to Tables 8-10, but based on the proposed distribution rates for the Acquired Utilities.

Response

a. The common variable rate is determined by the following process:
- Total class revenue requirement is determined by multiplying total class customer counts and energies by target rates [Total Rev]
- The Phase-In service charge is determined as Truncated [Existing rate] + [Target Rate less Existing Rate] / 4 Year Phase in Period
- The resultant Service Charge revenue for the class is derived [SrChg Rev] as the Phase-In Service Charge x total customers
- The necessary Variable Charge revenue [VarChg Rev] = Total Rev less SrChg Rev
- The common variable rate = VarChg Rev / total class energy

b. The Phase-In process would have all component classes of a new Rate Class having the same common variable rate. The different non-Common Variable Rates in Exhibit G1, Tab 8, Schedule 2, is due to the necessary mitigation process required for the Acquired customers. To achieve the average customer total bill impacts of 10%, a different variable charge from the Common Variable charge had to be adopted.

c. The average total bill is for the average customer per rate class as outline in Exhibit H, Tab 12, Schedule 53. The reference total bill is based on existing rates and the projected bill includes the retirement of Rider 1, the addition of Rider 3, the new RTSR rates and the new Total Loss Factors per rate class.

d. Refer to Response to Part a from above. For clarification, the proposed energy rate is not the target energy rate [except at the end of the 4 Year Phase-In period] but the common energy rate. The 10% ceiling is for impact levels up to 10% for the average customer per rate class.

e. The Year 1 revenue shortfall and customer numbers for each Acquired Distributor per rate class is presented in Attachment A.

f. The planned recovery period of the revenue shortfall per Rate Class is to be within the 4 Year Phase-In horizon if impacts allow. For those Acquired Distributors who could not be charged the common rate due to total bill impact constraints, in subsequent years their variable rates are increase beyond the annual common rate if

average total bill impacts allow to recover the shortfall from previous periods. Each Acquired Distribution will not pay more than their shortfall contribution in total.

g. Yes, the data in Tables 8, 9 and 10 are based on the average customer Total Bill impacts using the target rates.

h. Tables 8, 9 and 10 have been revised using proposed 2008 rates and are provided as Attachment B.

Table 8 with 2008 Proposed Rates

Range of impacts as a result of Harmonization of Residential Customers of Acquireds

Urban Residential			Residential R1		
# LDCs	# Cust	Impact Range %	# LDCs	# Cust	Impact Range %
0	-	0 to 2	1	354	0 to 1
2	6,144	2 to 4	3	3,373	1 to 2
4	15,193	4 to 6	3	794	2 to 3
0	-	6 to 7	0	-	3 to 4
0	-	7 to 8	4	1,993	4 to 5
1	6,347	8 to 9	1	100	5 to 6
5	33,463	9 to 10	0	-	6 to 7
			6	5,202	7 to 8
			28	20,171	8 to 9
			42	40,695	9 to 10
12	61,147		88	72,682	

Table 9 with 2008 Proposed Rates

Range of impacts as a result of Harmonization of energy General Service customers of Acquireds

Urban GS			GSe		
# LDCs	# Cust	Impact Range %	# LDCs	# Cust	Impact Range %
1	284	<0	1	63	<0
1	441	0 to 2	5	582	0 to 5
1	777	2 to 4	2	91	5 to 5.5
1	294	4 to 5	1	81	5.5 to 6
0	-	5 to 6	3	176	6 to 6.5
2	1,534	6 to 7	3	184	6.5 to 7
3	1,266	7 to 8	3	106	7 to 7.5
2	1,647	8 to 10	1	57	7.5 to 8
			2	696	8 to 8.5
			69	10,596	8.5 to 9
11	6,243		90	12,632	

Table 10 with 2008 Proposed Rates

Range of impacts as a result of Harmonization of demand General Service customers of Acquireds

Urban GS			GSd		
# LDCs	# Cust	Impact Range %	# LDCs	# Cust	Impact Range %
1	26	0 to 2	1	9	<-2
1	40	2 to 4	3	8	-2 to 0
1	85	4 to 5	18	243	0 to 5
0	0	5 to 6	3	12	5 to 5.5
1	27	6 to 7	3	184	5.5 to 6
1	104	7 to 8	0	0	6 to 6.5
6	373	8 to 10	2	31	6.5 to 7
			2	15	7 to 7.5
			1	5	7.5 to 8
			3	54	8 to 8.5
			31	389	8.5 to 9
			16	184	9 to 9.5
			3	33	9.5 to 10
11	655		86	1,167	

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #81 List 1

Interrogatory

Reference: Exhibit G2, Tab 4, Schedule 1, pages 2-3

Question:

a) Is the Coincident Peak for customers in the ST Class measured at each customer's delivery point or is it adjusted for losses and measured at the Transmission Delivery Point? If the former, please recalculate the allocated charges based on the ST Coincident Peak marked up for losses.

b) Why is the Coincident Peak of the ST class used for all Transmission charges when Line and Transformation Connection are charged on a NCP basis?

c) Please recalculate the allocation of Line and Transformation Connection costs by allocating Total Connection costs to all classes (including the ST Class) using the approach set out on page 3, lines 22-28.

Response

a. The ST Class demand used was at the Wholesale level [inclusive of losses] to be consistent of the IESO charges which is also at the Wholesale level.

b. The coincident peak of ST is used only to allocate the estimated IESO charges and not as the charge determinant for the Connection Charges.

c. Refer to Exhibit H, Tab 1, Schedule 160.

It would be inappropriate to allocate the costs to the ST class based on the Equations 11.3(a) and 11.3(b) listed in Chapter 11 because better cost causality is achieved by allocating the ST their proper amount and then to use the more generic equations to allocate the residual balances. Further, the generic equations do not distinguish between the Line Connection and Transformation Connection Cost Pools. The result would be a pooling of the ST customers assuming all customers would use both connections.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #82 List 1

Interrogatory

Reference: Exhibit G2, Tab 2, Schedule 5, pages 1-4

Question:

a) Please provide a Schedule that lists the number of UR customers (per new classification) in the Hydro One's Legacy System and in each Acquired LDC.

b) On the Schedule provided in response to part (a) please indicate of those customer now in the new UR class:
- The number of former Caledon OH-01 customers that use more than 2,000 kWh per month
- The number of former Quinte West residential customers that use less than 500 kWh per month

Response

The stated reference is incorrect. It should be Schedule 1.

a. The class composition of the new Urban Residential Rate Class is presented below

Rate Class	Customers
UR	82,519
F1	128
R1	11,753
R2	293
Legacy	**94,693**
Arnprior	2,848
Brockville	8,146
Caledon OH 01	8,794
Carleton Place	3,618
Dryden	2,526
GBE	7,638
Lindsay	6,347
Perth	2,745
Quinte West	5,657
Smiths Falls	3,637
Thorold	5,963
Whitchurch Stouffville	3,228
Acquireds	**61,147**
Total	**155,840**

b. The requested details limited to only the Acquired customers mapping to UR is not available. Only total Acquired Distributor metrics is available.
   - Caledon OH-01
     - There are 191 residential customers who have an average monthly consumption greater than 2,000 kWh.
   - Quinte West
     - Quinte West has in total 6,662 customers of which 5,657 will be mapped to UR
     - Of the 6,662 customers, 1,671 have average monthly consumption less than 500 kWh
     - If extend the same share, approximately 1,420 urban residential customers would have average monthly consumption of less than 500 kWh

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #83 List 1

Interrogatory

Reference: Exhibit G2, Tab 2, Schedule 5, pages 5-27

Question:

a) Please provide a Schedule that lists the number of R1 customers (per new classification) in the Hydro One's Legacy System and in each Acquired LDC.

b) On the Schedule provided in response to part (a) please indicate of those customer now in the new R1 class:
- The number of former Ailsa Craig residential customers that use less than 250 kWh per month.
- The number of former Arkona residential customer that use less than 500 kWh per month.
- The number of former Arran-Elders residential customers that use less than 500 kWh per month
- The number of former Blyth residential customers that use less than 500 kWh per month.
- The number of former Champlain residential customers that use less than 250 kWh per month.
- The number of former Fenelon Falls residential customers that use less than 500 kWh per month.
- The number of former Kirkfield residential customers that use less than 500 kWh per month
- The number of former Lanark Highlands residential customers that use less than 250 kWh per month
- The number of former Malahide residential customers that use less than 250 kWh per month
- The number of former North Dorchester residential customers that use less than 250 kWh per month
- The number of former North Dundas residential customers that use less than 250 kWh per month.
- The number of former North Glengarry residential customers that use less than 500 kWh per month
- The number of former North Stormont residential customers that use less than 500 kWh per month.
- The number of former Perth East residential customers that use less than 500 kWh per month
- The number of former Quinte West residential customer that use less than 500 kWh per month.

- The number of former Ramara residential customers that use less than 500 kWh per month
- The number of former Rockland residential customers that use less than 500 kWh per month
- The number of former Severn residential customers that use less than 250 kWh per month
- The number of former Glengarry residential customers that use less than 500 kWh per month
- The number of former Thorndale residential customer that use less than 500 kWh per month.
- The number of former Tweed residential customers that use less than 500 kWh per month
- The number of former Wardsville residential customers that use less than 250 kWh per month.
- The number of former Woodville residential customers that use less than 500 kWh per month.

Response

a. The new R1 rate class composition is listed in the following table by Legacy Rate Class and Acquired Distributor.

Rate Class or Acquired Distributor	**Number of Customers**
R1	292,508
Ailsa Craig	348
Arkona	217
Arnprior	286
Arran-Elderslie	1,675
Artemesia	412
Bancroft	1,001
Bath	737
Blandford-Blenheim	838
Blyth	382
Bobcaygeon	1,641
Brighton	2,320
Brockville	192
Caledon CH 02	2,118
Campbellford-Seymour	1,427
Carleton Place	93
Cavan-Millbrook-North Monaghan	560
Centre Hastings	647
Chalk River	376

Champlain	1,715
Cobden	469
Deep River	1,741
Deseronto	664
Dryden	108
Dundalk	687
Durham	1,110
Eganville	545
Erin	904
Exeter	1,986
Fenelon Falls	970
Forest	1,167
GBE	195
Georgina	1,132
Glencoe	850
Grand Bend	1,038
Hastings	503
Havelock	510
Kirkfield	107
Lanark Highlands	337
Larder Lake	383
Latchford	186
Lindsay	167
Lucan Granton	850
Malahide	243
Mapleton	722
Markdale	632
Marmora	579
McGarry	297
Meaford	2,026
Middlesex Centre	398
Napanee	2,036
Nipigon	728
North Dorchester	713
North Dundas	1,509
North Glengarry	1,901
North Grenville	1,359
North Perth	2,416
North Stormont	335
Omemee	506
Perth	100
Perth East	548
Prince Edward	3,092
Quinte West	1,005
Rainy River	378
Ramara	99

Red Rock	354
Rockland	3,536
Russell	847
Schreiber	593
Severn	577
Shelburne	1,703
Smiths Falls	99
South Glengarry	440
South River	473
Springwater	735
Stirling-Rawdon	808
Thedford	295
Thessalon	550
Thorndale	134
Thorold	1,139
Tweed	660
Wardsville	143
Warkworth	258
West Elgin	989
Whitchurch Stouffville	66
Wiarton	893
Woodville	320
Wyoming	829
Terrace Bay	1,025
Total R1 Class	365,190

b. The following table lists the requested Acquired customers who have average monthly consumption at less than 250 kWh and less than 500 kWh based on 2006 consumption data, as well as showing the total projected customers mapping to the new R1 rate class. The numbers for Quinte West have been scaled by the number of customers moving to UR versus R1.

Acquired Distributor	LT 250	LT 500	Total R1
Ailsa Craig	17		348
Arkona		57	217
Arran-Elderslie		309	1675
Blyth		105	382
Champlain Twp	131		1715
Fenelon Falls		250	970
Kirkfield		18	107
Lanark	21		337
Malahide	8		243
North Dorchester	39		713
North Dundas	68		1509

North Glengarry		418	1901
North Stormont		99	335
Perth East		96	548
Quinte West		252	1005
Ramara		21	99
Rockland		647	3536
Severn	32		577
South Glengarry		95	440
Thorndale		29	134
Tweed		173	660
Wardsville	8		143
Woodville		45	320

School Energy Coalition (SEC) INTERROGATORY #1 List 1

Interrogatory

Ref: A/10/2, Management's Discussion and Analysis 2007 Quarterly Report:

a. Pg. 5, please provide the cost rate for the $400 million in long-term debt issued in the first quarter of 2007.
b. Pg. 9: please provide a copy of the rationalization plan approved by the government on March 19, 2007.
c. Pg. 9: Please provide a copy of the agreement, if any, reached with the Society of Professional Engineers by May 31, 2007.

Response

a. The cost rate for the $400 million in long term debt is discussed on lines 9 to 11 of page 4, Exhibit B1, Tab 2, Schedule 1.

b. Please see Attachment A. It can also be found on Hydro One's external website at:

http://www.hydroonenetworks.com/en/customers/LDCs_and_Tx/communications/distribution_rationalization_strategy/default.asp

c. See Attachment B.

Hydro One Networks Inc.
Distribution Rationalization Strategy

1) Introduction

The Minister of Energy wrote to Hydro One on October 17, 2006 to confirm the government's priorities for the structural efficiency and productivity in Ontario's electricity distribution sector. The Minister's letter stated the following:

> "We believe that further consolidation, undertaken on a voluntary and commercial basis, can help drive sector efficiencies, reduce costs and create an industry structure conducive to undertaking the size and scope of capital investment required for system upgrades and new investment, improved system reliability, and implementation of the government's smart metering agenda."

The Minister's letter also requests that Hydro One provide the Ministries of Energy and Finance with an opportunity to review Hydro One's proposed strategy and critical path for rationalization. This document is intended to satisfy the Minister's request.

2) Principles Guiding Hydro One's approach to Distribution Rationalization

The provincial government has set the following objectives for Distribution Rationalization in Ontario:

- More efficient system configuration
- Improved service quality
- Rate stability
- Enhanced financial viability for the sector

Hydro One will support the provincial government's objectives for the electric distribution sector by using the following approach in the acquisition, partnering or sale of distribution assets and customers:

Distribution Rationalization Implementation – Proposed Approach

Acquisition Strategy	Hydro One will be seeking to acquire LDCs (Local Distribution Companies) embedded in Hydro One's service territory. Deals will be voluntary and commercial. Approach will be non-aggressive, working in cooperation with LDC management and shareholders. Hydro One will also consider commercial proposals to partner or swap assets where this helps create large, contiguous entities.
Divestiture Strategy	Hydro One will consider proposals to divest assets where these are embedded in the service territories of urban LDCs. Deals must be voluntary and commercial to avoid negative impact on Hydro One's returns, goodwill, credit rating, and customers. Staging is important to mitigate stranded cost risk. Ideally, acquisitions will take place ahead of divestitures and at least offset divestitures.
Municipal Relations	Local field management to have direct municipal relationship management role post acquisition.
Local Operations	Integrate into Hydro One Networks, but with greater flexibility for local operations for larger LDCs, consistent with Hydro One's approach to increase local presence and regional accountabilities.
Treatment of Staff	Age demographics in industry have created a need for skilled staff. In case of divestiture, our collective agreements will apply.
Industry Change	Rationalization will help deliver policy priorities like conservation, smart meters and improved operating and regulatory cost effectiveness.
Rates	Use existing LDC rates on interim basis. Future rates subject to OEB review and approval.
Regulatory Approvals Process	Request streamlined approvals processes for contiguous and embedded transactions.

It is anticipated that this approach will lead to larger and fewer LDCs, with more rational geographic boundaries. Given that the process will be voluntary and commercial, and each LDC's shareholder will decide on its own future, it is not possible to predict a specific end state.

3) Process

Hydro One will respond to all inquiries regarding the sale, purchase or partnering of local distribution assets and customers. Consistent with the principles that have been set out by the Minister of Energy, Hydro One will establish criteria to assess proposals submitted for consideration. We will assess each case on its own merits and as to whether the deal is economic for Hydro One and is beneficial to its customers.

Specifically, we will develop a process to review requests on the basis of principles set by the Minister of Energy in his letter to Hydro One's Chair dated October 17, 2006. To administer this review, we will use an outside consultant to complete the screening of these proposals and to provide feedback to the LDCs.

4) Communications

Hydro One will maintain open and transparent communications with stakeholders throughout the transfer tax window.

Inquiries from LDCs or municipalities regarding an interest in either selling their LDC or acquiring Hydro One customers and assets should be directed in writing to the Vice President, Asset Management.

5) Risks

The sale of Hydro One customers without offsetting acquisitions could lead to the loss of scale economies and stranded costs, which could represent a significant financial risk to Hydro One and its shareholder, the Province.

Our proposed mitigation measure is to match the number of customers we are willing to sell with the number of customers that we are able to buy. This way, the fixed costs incurred to serve existing customers will not have to be spread over a smaller customer base, thereby putting upward pressure on rates for the remaining Hydro One customers.

6) Governance

Transactions will be subject to the approval of Hydro One's Board of Directors. Hydro One will provide ongoing reports to the Ministries of Energy and Finance to advise them on the status of the program.

May 31, 2007

Memorandum of Agreement

Between
Hydro One Inc.
hereafter referred to as the Company

- and -

The Society of Energy Professionals

Now, therefore, the parties herein agree the following constitutes full settlement of all matters. This Memorandum of Agreement is subject to ratification by both parties before the following shall constitute full and final settlement of all matters.

The parties also agree that this Hydro One Inc. – Society Collective Agreement shall include the terms of the April 1, 2005 - March 31, 2008 Hydro One Inc. – Society Collective Agreement provided, however, that all matters set out in the attached statement of Agreement are incorporated.

For the Union | **For the Company**

Date May 31/07

It is jointly agreed that the Collective Agreement covering the period of April 1, 2005 to March 31, 2008 will be amended as follows. All changes will be effective July 1, 2007 unless otherwise dated. The parties herein agree that the term of the Collective Agreement shall be from April 1, 2008 – March 31, 2013.

1. **Term**

   a. Five year term, from April 1, 2008 – March 31, 2013. The parties will jointly seek early termination of the current Collective Agreement before the Ontario Labour Relations Board.

2. **Compensation**

   a. Wage Schedules

      i. Increase all schedules by 3.0% on April 1, 2008, April 1, 2009 and April 1, 2010. Increase all schedules by 2.5% on April 1, 2011 and April 1, 2012.

   b. Escalator Clause

      i. The current Escalator Clause formula as described in Article 24 of the Collective Agreement will apply in the third, fourth and fifth years. For the fourth and fifth years, a 2.5% increase in the Ontario CPI will activate the escalator clause.

   c. Salary Progression

      i. Effective October 1, 2007 delete Article 31 and replace the performance pay plan with a new progression plan as per below. For clarity, the normal minimum performance plan payout of 1.0% of base pay for the performance year 2007 will not be made at the end of 2007.

      ii. A new progression plan will be implemented on October 1, 2007 that includes the following features:

         a. Three salary schedules will be created, recognizing 35-hour, 37.5-hour and 40-hour work weeks. The 35-hour schedule will replace Schedule 01, the 40-hour schedule will replace schedule 08 and the 37.5-hour schedule will replace schedule 02. Current prorating pay treatment for base hours as per Article 68 remains unchanged with the exception of those covered under LOU #5.

         b. The current job evaluation plans will continue to apply.

         c. Progression will be on an annual basis.

         d. The MP1 salary band will be eliminated and MP2 through MP6 salary bands will remain.

         e. Salary ranges for all salary bands shall be equivalent to current

70% - 100%.

f. Progression from 70% to 100% shall be as follows:

   i. 70% to 80% in 5% steps

   ii. 80% - 88% in 4% steps

   iii. 88% to 100% in 3% steps

g. Schedule 04 is eliminated as it is incorporated into the initial steps of MP2. All new grads will be hired at either 70% or 75% of MP2. Article 25 will be amended and/or obsoleted as required.

h. Employees will automatically progress to the next step on their anniversary date of appointment to their position unless withheld by management.

iii. Amend Article 66.2.2 and delete Article 66.2.3

a. (66.2.2) A promoted employee will be placed at the *step* which reflects a reasonable expectation of his/her performance in the new or revised job.

iv. Delete Article 19.4 and replace with the following:

a. If an employee fails to make satisfactory progress, his/her progression may be withheld for a period of six months.

b. In taking this action, the Employer shall provide the employee with one month's notice with written reasons for withholding the progression and what is required to rectify the unsatisfactory performance.

c. The performance of an employee whose progression has been withheld as above will be reviewed within six months. If progress and general performance are found to be satisfactory, progression shall be granted and the review date becomes the employee's new anniversary date. However, if progress and general performance are not satisfactory, the employee shall be either transferred or dismissed.

d. If six months after the review his/her performance has continued to be satisfactory, he/she may be granted the next step in his/her progression. This will then re-establish his/her original progression status.

v. Transition:

a. Effective October 1, 2007, all current employees will be mapped to the step nearest in the applicable salary band that is not less than their current pay.

b. All employees paid above the rate for the highest step in their salary band will be "green circled" i.e. will continue to be eligible to receive economic increases.

c. October 1 will become the "anniversary date" for employees except as follows:

i. For employees who are appointed to a different position or persons hired into Society-represented positions subsequent to the implementation date, their anniversary date will become the date of appointment to this new position.

3. **The Society's Unfair Labour Complaint (ULP) and Union Discrimination Grievance are withdrawn subject to the following:**

a. The parties agree to the settlements contained in Appendix C.

b. Staffing:

- By the end of Year 4 of the contract, a minimum of 20% of the regular workforce will be regular Society-represented staff
- Failure to meet the 20%, in cases of force majeure or extraordinary circumstances, will trigger discussion and/or mediation/arbitration
- By the end of the contract, 20% - 25% of the regular workforce will be regular Society-represented staff. Management may, at its discretion, exceed the 25% level if deemed appropriate.
- Movement within the 5% range will be determined by the approved work program and/or resource mix requirements. Disagreements on this will trigger discussions and/or mediation/arbitration
- The Operations Committee will meet with the Society on an annual basis to review the approved work program and resource mix requirements
- The Problem Solving Committee will monitor this entire process

- This agreement, which shall not be reproduced in the Collective Agreement, expires at the end of this Collective Agreement (March 31, 2013)

c. Jurisdictional Issues

i. The jurisdictional grievances listed in Appendix "A" are withdrawn and will not be re-filed by the Society. This withdrawal is without prejudice to the Society's position in any future jurisdictional dispute

ii. The parties agree that the jurisdictional landscape, as of the date of signing, will remain "frozen" for the term of the collective agreement (except as outlined in (iii) below). Specifically, Hydro One will not alter or amend any existing Society represented jobs such that as a result they fall outside the Society's jurisdiction. Hydro One can introduce newly created MCP jobs, which will be processed in accordance with the new exclusion process (iv) that follows, during the term of the collective agreement. Also, Hydro One can replace individuals who leave existing MCP jobs during the term of the collective agreement or add additional positions to existing MCP jobs.

iii. 16 of the challenged excluded positions will be returned to the Society's jurisdiction and where vacant, posted and filled. The remainder shall remain as MCP. The selection of the 16 positions shall be at Management's discretion.

iv. Article 2.5 (2) and (3) will be replaced with the following:

(2) If a new or changed job is excluded from the Society's jurisdiction ~~based on the new criteria outlined in (v) below~~ and the Society has concerns with the exclusion, the parties will meet within 15 days of the exclusion request to attempt to resolve any outstanding issues.

(3) If the parties are unable to resolve the issues, the Society can request that the dispute be submitted to expedited arbitration. A hearing will be held within 30 days of the referral, and a decision will be rendered within 15 days of the hearing. Management cannot implement the exclusion until the Arbitrator's decision. The Society must inform Hydro One of their intent to request arbitration within 10 days of the meeting taking place. If the Society does not request arbitration, Hydro One is free to implement the excluded position.

v. Exclusion Criteria:

a. The parties agree to delete the 335 point exclusion criterion and appoint a committee to create a new exclusion criterion to replace 335.

b. For the sake of clarity:

i. The new exclusion criterion will only apply to persons who do not meet the "other exclusion criteria", e.g. persons who are not:

- Performing managerial functions as opposed to supervisory functions; or
- Employed in a confidential capacity with respect to labour relations; or
- Represented by another trade union

ii. The "other exclusion criteria" (all except for 335) are unchanged by the Memorandum

iii. This replacement criterion only applies to first-level MCP positions (i.e. the first reporting level above Society-represented employees). The intent of this restriction is to ensure that no MCP person reports to a Society-represented employee.

c. The committee will also determine which excluded jobs will be subjected to Article 2.5 (2) and (3) outlined above

d. In developing the replacement criterion, the parties will attempt to develop criteria to determine when the inclusion of a person within the Society's bargaining unit is likely to result in a conflict of interest with respect to the nature of and extent of a job's accountabilities and authorities for business decisions, confidentiality and/or impact on the company.

e. The committee will complete their discussions within six months of the date of ratification and at that time will report back to their respective bargaining teams. Failing agreement on the new exclusion criteria and/or exclusion process, the matter shall proceed to mediation/arbitration in front of Kevin Whitaker. Mediator/Arbitrator Whitaker will utilize the principles outlined above in rendering his decision.

vi. The parties agree to jointly request PWU concurrence with and participation in a tripartite expedited dispute resolution process to resolve Society-PWU jurisdictional grievances, including those listed in Appendix "B". If the PWU declines to participate, the Society retains the right to refer these grievances to the existing arbitration process.

d. <u>Standard Hours / Inflexible Hours</u>

i. Any and all issues associated with Standard Hours / Inflexible hours are

withdrawn and will not be re-filed by the Society, based on the parties' belief that this issue has generally resolved itself and in recognition of item 7 (a) below.

e. Contracting Out / Use of Contractors

i. The grievances listed in Appendix "D" are withdrawn and will not be re-filed by the Society:

ii. Article 67 will be suspended for the term of the Collective Agreement save and except for the last bullet which reads "No employee will be laid off as a direct result of contracting out"

iii. The parties agree to establish a sub-team to review the Society's "dependent contractor" policy grievance (HYDO-2005-2384). This review will be completed by September 15, 2007. Failing agreement between the parties, the Society may refer any unresolved issues to mediator-arbitrator Robert Herman. For clarity, only the merits of this issue can be discussed and if needed, arbitrated. No issues of anti-union animus, discrimination, etc. can be raised throughout this process.

4. Pensions

a. Article 22.9:

- *Employer will ensure affected employees are notified of their election options, including the default selection and the fact that the default option does not afford the employee the option to buy-back service. The Employer will copy the employee's Society Unit Director on this notice.*

5. Benefits

a. Increase eyeglass coverage to $475 (per person, 2 year period) effective January 1, 2009 and to $500 (per person, 2 year period) effective January 1, 2011.

b. Language will be added to the Benefit Book to reflect the following:

Pensioners and surviving spouses of pensioners who enter into marriage or common-law marriage are precluded from adding their new spouse and/or new children as dependents on the Hydro One Health and Dental Plan.

Surviving spouses of employees who enter into marriage or common-law marriage are precluded from adding their new spouse and/or new children as dependents on the Hydro One Health and Dental Plan.

c. Life Insurance:

Effective April 1, 2008, the Employer will no longer subsidize the cost of optional Life Insurance.

6. Problem Solving Committee

a. A Problem Solving Committee shall be established and constituted of the Hydro One Operations Committee and the Society VP and Unit Directors. The Problem Solving Committee shall meet quarterly.

b. The Problem Solving Committee Oversight Committee shall consist of the President and CEO of Hydro One and the President of the Society and shall meet bi-annually. The Oversight Committee may request the assistance of Kevin Whitaker as required.

7. Hours of Work

a. The start time window is established, to allow a flexible start-time, between 7 am – 9 am

8. Society Representative Release Time

a. For the term of the Collective Agreement, the parties agree to continue the agreements with respect to Unit Director and Vice President

9. Security Clearances

a. The Society acknowledges and agrees that the Employer has the right to perform appropriate Personal Risk Assessments (PRA) on existing, regular employees when required for valid reasons. Where the Employer has reasonable cause to remove an employee from his/her position as a result of an employee's inability to pass a PRA, the employee will be transferred to an equivalent position for which a PRA is not required with no loss of salary.

10. Vacancies

a. Amend Article 66.6:

- *For voluntary demotions, the employee will take the rate of the lower-rated position except as follows:*
  - *Where employee involuntarily demoted pursuant to Article 64, "red-circling" will continue until employee's new pay rate exceeds frozen level, regardless of number of appointments*

11. <u>Flexibility and Bureaucracy within the Collective Agreement</u>

a. The parties agree to form a committee to examine ways to improve upon the flexibility and reduce the bureaucracy of the Collective Agreement

12. <u>Finalization of the New Collective Agreement</u>

a. The parties agree to incorporate, as applicable, the relevant terms of this Memorandum of Agreement into the collective agreement within 90 days of its ratification. In the event the parties are unable to resolve any disputes arising from this process, either party may refer unresolved items to Kevin Whitaker for expedited final and binding arbitration.

APPENDIX "A"

- The individual contributor grievance
- OGCC Pre-Strike Exclusions (HYDO-2005-2395/2389)
- Grid Operations Manager (HYDO-2005-2374)
- Senior Financial Advisor – Financial Systems (HYDO-2006-2398)
- Senior Financial Advisor – Financial Planning & Analysis (HYDO-2006-2399)
- Senior Financial Advisor – External Financial Reporting (HYDO-2006-2400)
- Senior Financial Advisor – Corporate Accounting (HYDO-2006-2401)
- Senior Financial Advisor – CF&S (HYDO-2006-2402)
- Senior Financial Advisor – Internal Financial Reporting (HYDO-2006-2403)
- Senior Advisor – Emergency Preparedness (HYDO-2006-2409)
- Manager – P&C Technical Services (HYDO-2006-2407)
- Facilities Manager (HYDO-2006-2410)
- Senior Health, Safety and Environment Advisor (HYDO-2006-2416)
- Forestry Technician Manager (HYDO-2006-2417)
- Manager, Conservation Demand Management (HYDO-2006-2421)
- Performance Manager (HYDO-2006-2429)
- Team Lead – Stations Engineering (HYDO-2006-2432)
- Systems Support Manager (HYDO-2006-2433)
- Team Lead – Lines Engineering (HYDO-2006-2434)
- Team Lead – P&C&M Engineering (HYDO-2006-2436)
- Team Lead – Telecom Engineering (HYDO-2006-2435)
- Grid Operations Planning Manager (HYDO-2006-2441)
- Customer Operations Manager (HYDO-2006-2442)
- Manager, Customer and Business Services (HYDO-2006-2443)
- Manager, Field Administrative Services (HYDO-2006-2444)
- Grid Operations Field Manager (HYDO-2006-2445)
- Sustainment Manager (HYDO-2006-2446)
- Transmission Planning Manager (HYDO-2006-2467)
- WM&TS band 6 jobs (HYDO-2006-2484)
- Manager, Financial Services Corporate Controller
- Manager Data Manager (HYDO-2006-2404)
- Integrated Process Manager (HYDO-2006-2405)
- HSE Engineering Technical Specialist (HYDO-2006-2408)
- Training Manager (HYDO-2006-2415)
- Senior Treasury Operations Advisor (HYDO-2006-2422)
- Senior Advisor – Load Data Management (HYDO-2006-2426)
- Senior Advisor – Load Forecasting (HYDO-2006-2427)
- Manager, Financial Business Services (HYDO-2006-2430)

- Senior Financial Advisor - Business Controls (HYDO-2006-2431)
- Senior Advisor – Pricing and Rates (HYDO-2006-2407)
- Senior Advisor – Regulatory Policy & Client Support (HYDO-2006-2437)
- Manager – Business & Strategic Planning (HYDO-2006-2438)
- Standards Development Advisor (HYDO-2006-2466)
- Special Studies Manager (HYDO-2006-2468)
- Manager – Interconnections (HYDO-2006-2469)
- Distribution Generation Connection Planning Manager (HYDO-2006-2470)
- Reliability Standards Manager (HYDO-2006-2489)
- Forestry Manager (HYDO-2006-2510)
- Forestry Superintendent – Business Services (HYDO-2006-2511)
- Manager, Meter Relay and Data Acquisition Services (HYDO-2006-2501)
- Manager, MSP Services (HYDO-2006-2500)
- Distribution Technician Manager (HYDO-2006-2503)
- Manager, Financial Services – Remotes (HYDO-2006-2411)
- Programs Support Manager (HYDO-2006-2465)
- Senior Regulatory Financial Advisor (HYDO-2006-2447)
- Team Lead – Environmental Engineering (HYDO-2006-2472)
- Commercial Agreements Manager (HYDO-2006-2473)
- Program Integration Manager (HYDO-2006-2493)
- Customer Services Manager (HYDO-2006-2412)
- Senior Advisor – Regulatory Policy and Client Support
- Manager, Business and Strategic Planning (HYDO-2006-2504)
- Customer Program Manager (HYDO-2006-2439)
- Business Systems and Support Manager (HYDO-2006-2413)
- Work Methods Manager (HYDO-2006-2414)
- Manager, Development and Deployment (HYDO-2006-2418)
- Manager, Customer Contracts and Programs (HYDO-2006-2419)
- Manager, Financial Planning and Reporting (HYDO-2006-2420)
- Senior Treasury Advisor (HYDO-2006-2424)
- Senior Advisor, Regulatory Research and Admin (HYDO-2006-2425)
- Manager, Business Planning (HYDO-2006-2438)
- Manager, Financial and Accounting Services (HYDO-2006-2505)
- Senior Advisor – Decision Support (HYDO-2006-2513)
- Support Networks Manager (HYDO-2006-2423)
- Principal Advisor – P&C Policy Standards (HYDO-2007-2026)
- Principal Advisor – P&C Sustainment (HYDO-2007-2026)
- Principal Advisor – Revenue Metering (HYDO-2007-2026)
- Principal Advisor – Telecommunications Sustainment (HYDO-

2007-2026)

- P&C Strategies and Sustainment Manager (HYDO-2007-2026)
- Data Quality & Change Control (HYDO-2006-2428)
- Desktop Support Services (HYDO-2006-2440)
- Manager Financial Services (HYDO-2006-2491)
- Any other jurisdictional grievance filed as of the date of this Memorandum of Agreement and/or any jurisdictional issue that arose prior to the date of this memorandum

APPENDIX "B"

The PWU-Society Jurisdictional grievances:

- UTS grievance (HYDO-2006-2492)
- Outage Response Technician (HYDO-2006-2454)
- Senior Planning Technician (HYDO-2006-24560
- Grid Operations Area Leader (HYDO-2006-2455)
- Operations Support Technician (HYDO-2007-2528)
- GIS Systems Support Technologist (HYDO-2006-2488)

APPENDIX "C"

The parties agree all Removal from Role, Overtime, On-Call and Discrimination grievances are settled as follows and on a without prejudice or precedent basis.

1. REMOVAL FROM ROLE

GRIEVANCES HYDO-2006-2458, HYDO-2006-2449, HYDO-2006-2498, HYDO-2007-2521, HYDO-2006-2461, HYDO-2006-2464, HYDO-2005-2393, HYDO-2006-2480, HYDO-2005-2383 and HYDO-2006-2474 are resolved on the following basis:

a. The parties agree that the above-referenced grievances encompass the employees contained in confidential attachment "E":

b. These employees will be offered the opportunity to avail themselves of Article 85. In order to participate, affected employees must notify Keith McDonell, Human Resources in writing within 30 calendar days of ratification of this collective agreement. The formula for payment is three weeks per year of service to a maximum of 52 weeks.

c. For those employees who do not avail themselves of option (b) above, the Society and Hydro One shall meet within 60 days of ratification to determine the appropriate treatment of those remaining. The parties will make an offer to the employees from one of (i), (ii) or (iii) within 60 days of ratification.

   i. Reinstatement in the position from which he or she was removed if the successor MCP job returns to the Society's jurisdiction and the position is vacant.

   ii. Conversion of the current assignment into an on-going position with an appropriate job document (to be developed if necessary)

   iii. "Waive" an employee into a vacant, equivalent ongoing position

   iv. If (i), (ii), or (iii) are not appropriate or the employee refuses an offer, the employee will continue in his/her current assignment. In addition, when deemed qualified by management, will have a "selection priority" ahead of 65.6.3 (f) for a period of two (2) years from the date of ratification.

GRIEVANCES HYDO-2006-2462, HYDO-2006-2396 AND THE UNION DISCRIMINATION GRIEVANCE are resolved on the following basis:

1. Generic Overtime Issue

a. There is no current nor past direction from Hydro One Senior Management that prohibits Society members from working overtime or taking on-call.

b. The parties acknowledge that the utilization of OT and on-call is at management's discretion and must be managed in accordance with the collective agreement.

c. The Society has brought forward allegations that certain Managers have inappropriately applied the collective agreement as it pertains to overtime and/or on-call for Society members.

d. Without acknowledging the voracity of the Society's claims as outlined in number 3 above and without acknowledging any violation of the collective agreement, Hydro One Senior Management will issue a clarification to all Management staff to ensure that overtime and on-call are managed in line with the collective agreement and are based upon appropriate business requirements.

e. By issuing this clarification, this generic issue is removed from the ULP and deemed settled.

2. Specific Overtime Issues:

a. The settlements to the above-referenced grievances are contained in confidential attachment "E"

2. UNFAIR TREATMENT / DISCRIMINATION GRIEVANCES

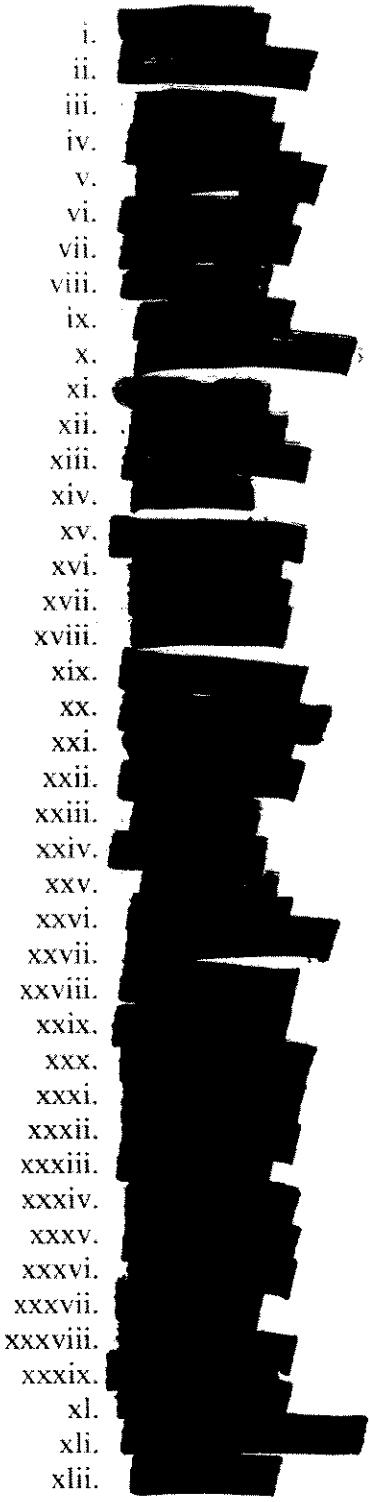
GRIEVANCES HYDO-2006-2452, HYDO-2006-2509, HYDO-2006-2464 AND HYDO-2006-2482 shall be resolved on the following basis:

a. The settlements to the above-noted grievances are outlined in confidential attachment "E"

APPENDIX "D"

- Former Temps rehired as "External Contractors" (HYDO-2005-2383)
- Guelph Cedar TS and Belle River TS (HYDO-2005-2369/2373)
- Project Management of Telecom/SCADA Projects (HYDO-2006-2448)
- Any other grievance associated with contracting out / use of contractors filed as of the date of signing this memorandum and/or any issue that arose regarding contracting out / use of contractors prior to the date of this Memorandum ~~except~~ EXCEPT FOR THE DEPENDENT CONTRACTOR GRIEVANCE AS NOTED IN ITEM 3(e)(iii) ON PAGE 7

1. REMOVAL FROM ROLE:



xliii. [redacted]
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2. SPECIFIC OVERTIME ISSUES:

b. [redacted] all be paid 3 hours at straight time

c. [redacted] shall be paid 3 hours at straight time

d. [redacted] all be paid 1 hour at straight time

e. [redacted] shall be paid 12 hours at straight time

f. [redacted] hall be paid 1 hour at straight time

g. [redacted] shall be paid 9 hours at straight time

h. [redacted] shall be paid 9 hours at straight time

i. [redacted] shall be paid 22 hours at straight time

j. [redacted] shall be paid 4 hours at straight time

k. [redacted] shall be paid 4 hours at straight time

l [redacted] deductions will be made from the above payments

3. UNFAIR TREATMENT / DISCRIMINATION GRIEVANCES

a. 2005 performance appraisals for [redacted] and [redacted] shall be removed from their 901 files

School Energy Coalition (SEC) INTERROGATORY #2 List 1

Interrogatory

Ref: C1/2/2, pg. 6; Sustaining OM&A: Stations: Planned Station Maintenance

a. Please provide a breakdown of the $2 million cost of inspecting Hydro One's stations in 2008.

b. Please explain why spending for this activity increases by almost 100% from 2004 ($6.6 million) to 2008 ($12.9 million). Please provide a detailed explanation of the drivers of the increase in spending during this time.

c. Please provide the number and the average age of distribution and regulating stations and mobile substations owned and operated by Hydro One Distribution, from 2003-2008.

Response

a) The following is the breakdown of the inspection costs for Hydro One Distribution Stations:

2008 Task	Inspection Spending
Monthly urban inspections @ 250 stations	$ 0.6
Spring inspections at other stations	$ 0.8
Fall inspections at other stations	$ 0.3
Maintenance during inspections	$0.3
Total	$2.0

b) The drivers that increase spending from 2004 to 2008 are:

- A significant increase in transformer overhauls, from 18 units in 2004 to 75 identified in 2008. Some of the additional overhauls were undertaken instead of purchasing new transformers. The overhaul option is now less expensive than new transformers because of significant increases in new transformer costs.

- Hydro One has introduced Dissolved Gas in Oil (DGA) testing of transformer Under Load Tap-Changers (ULTC) compartments. This has been an extremely successful program which allows Hydro One to prevent unplanned failures of transformer ULTC. With this program transformers are removed from service under planned, controlled conditions, lessening the impact to customers as well as the reducing failures.

- During 2004, Hydro One had not yet implemented the full range of maintenance activities at the utilities acquired during 2001, where in future years the full cost for maintenance was included.

c) The following table provides the number and the average age of distribution and regulating stations and mobile substations owned and operated by Hydro One Distribution, from 2003-2007. The number of stations is based on year end, therefore 2008 numbers are not included.

Year	Number of Distribution and Regulating Stations	Estimated Average Age of Distribution and Regulating Stations [1]	Number of Mobile Substations [2]	Estimated Average Age of Mobile Substations
2003	1016	23.0	28	29.2
2004	1013	23.9	28	30.2
2005	1009	24.8	28	31.2
2006	1006	25.7	28	32.2
2007	1007	26.7	28	33.2

Notes:
1. Average age of DS and RS is based on station in-service date where available or transformer age where available.
2. Average age of Mobile Substations based on transformer age.

School Energy Coalition (SEC) INTERROGATORY #3 List 1

Interrogatory

C1/2/2, pg. 12:

a. Please provide the number of trouble calls that Hydro One Distribution responded to annually, from 2004-2007.
b. Please break down the annual trouble calls spending (by dollar amount) into the following sub-categories: trouble calls, allowance for non-capitalized storm related costs – vegetation management, allowance for non-capitalized storm related costs – accumulated overtime during storm events, and other (if any).
c. Please advise why Hydro One didn't apply for a Z-factor rate adder related to 2006 storm damage claims in its 2007 IRM distribution rates application;
d. Please separately provide details of 2006 storm damage costs that were recorded in other expense / capital line items.
e. in determining the 2008 budget for Trouble Calls (under Sustaining OM&A-Lines-Trouble Call Response), how was the forecast number of trouble calls (49,100) determined?
f. How does the cost per trouble call for 2008, $1,199 ($58.9 million divided by 49,100 projected calls), compare with the 2004-2007 period? Please explain any variation in per unit cost.
g. Does the forecasted number of calls for 2008 take into account Hydro One's extensive vegetation management program?

Response

a. The following table is a yearly summary of the total number of OM&A Trouble Calls between 2004 and 2007.

Year	Trouble Call Units
2004	46,767
2005	49,935
2006	49,697
2007	49,384

b. The annual spending for OM&A Trouble Calls are as follows:

Category	2004 ($M)	2005 ($M)	2006 ($M)	2007 ($M)
Trouble Calls	$50.6	$48.7	$49.9	$52.2
Storm - Vegetation Management	$0.5	$3.4	$15.0	$1.3
Storm - Overtime Premium	$0.4	$4.7	$6.0	$4.0

c. Hydro one didn't apply for a z-factor rate adder in its 2007 IRM distribution rates application for a number of reasons:
   - a certain level of storm damage costs are included in distribution program spending approved by the Board,
   - the major storms in 2006 did not meet the materiality criteria set by the Board
   - historically, Hydro one has absorbed some of the cost of incremental storm damage spending via re-direction of other work programs or has absorbed these costs resulting in lower net income,
   - all storm related capital spending would be included in rate base for recovery as part of rebasing during a subsequent rates application.

d. The capitalized portion of storm restoration costs in 2006 was $62.0 million

e. The 2008 forecast number of trouble calls was based on a weighted 4-year average of historical accomplishments as indicated in the table below.

Year	Weight
2003	10%
2004	20%
2005	30%
2006	40%
Total (2008)	100%

f. The unit cost for Trouble Calls would not include non-capitalized storm related costs. This being the case, the projected cost for 2008 is $1,077 ($52.9 million divided by 49,100 projected calls) rather than the $1,199 noted in f) above. The average cost per unit between 2004 and 2007 was $1,029 ($201.4 million divided by 195,783 trouble calls from 2004 to 2007). The variance is 4.7% which is below escalation amounts over this period.

g. The 2008 program forecast does take into account the work accomplished by the Vegetation Management Program. The impact of the increasing accomplishments for the 2008 Vegetation Management Program is not expected to have a material affect on the 2008 Trouble Call Program. Noticeable benefits from increased vegetation management are not expected to materialize until several years into the program.

School Energy Coalition (SEC) INTERROGATORY #4 List 1

Interrogatory

Ref: C1/2/2: Sustaining OM&A: Line Maintenance

a. Pg. 15: Sustaining OM&A: Line Maintenance. Please explain why the budget for Line Patrols, Wood Pole Assessment and Asset Data Collection increases by 65% from 2004 ($8.1 million) to 2008 ($13.4 million).

b. How many kilometres of line/ number of poles were assessed in 2004 versus 2008?

c. Pg. 15: The evidence states, at line 20, that the approach adopted by Hydro One for line patrols meets the requirements of the Distribution System Code. Was Hydro One in compliance with the Distribution System Code in 2004? If so, what accounts for the 65% increase in spending on line patrols since then?

d. Line Sustaining OM&A- Other Services: why are the expenditures for these items not included in the total Line Sustaining budget at C2/2//2, pg. 15?

e. Pg. 22: Please explain the drivers for the increase in the 2007 forecast for Sustaining OM&A: Other Services from $9.6 million as originally filed (in the August 2007 filing) to $12.7 million in the updated evidence.

f. Pg. 22: Please provide a more detailed explanation for the fluctuation in Line Sustaining OM&A- Other Services-Miscellaneous Services from $2.9 million in 2004 to $7.7 million in 2007 (up from $5.6 million in the evidence filed August 15, 2007), to $4.9 million in 2008. (With respect to the evidence states only that the increase is due to "an increasing focus on Health and Safety consistent with the company's strategic goals.")

Response

a. As discussed in Exhibit C1, Tab 2, Schedule 2, page 16, Hydro One commenced a line data capture initiative in 2005. For economic efficiency, the initiative was bundled with line patrols and the data capture is expected to be complete in 2010. Expenditures associated with the initiative are budgeted to be $4.6 million in 2008. These expenditures were not present in 2004, the year before the data capture initiative commenced and they are the primary driver for the increase in expenditures.

b. In 2004, approximately 21,000 kilometres of line was assessed, which is the same as the 2008 budget.

c. Hydro One was in compliance with the Distribution System Code in 2004. Details on the increase in spending can be found in the answer to part a above.

d. Page 15 of Exhibit C1, Tab 2, Schedule 2 only shows expenditures attributed directly to line maintenance. "Other Services" are not directly associated with line maintenance and are detailed separately on page 22 of the Exhibit C1, Tab 2, Schedule 2.

e. The following table explains the drivers for the increase in actual costs:

Description	2007 Forecast (Aug. 2007)	2007 Actual	Driver for Increase
Customer Inquiries	$3.3	$3.8	Greater demand. Original forecast was based on 6,000 inquiries and actual was approximately 7,900.
Investigations & Data Collection	$0.7	$1.2	Greater demand for data requests.
Miscellaneous Services	$5.6	$6.2*	The aggregate of various small increases (e.g. more third party switching requests, greater amount of miscellaneous engineering and environmental support, and a greater emphasis on Environmental Health and Safety).
Total	**$9.6**	**$11.2**	

* The 2007 actual spend for Miscellaneous Services was $6.2 million rather than $7.7 million as identified in the February 20, 2008 update to Table 7, Exhibit C1, Tab 2, Schedule 2. Hydro One inadvertently included $1.5 million associated with Distribution Operating Map and Station Operating Diagram Maintenance as part of Miscellaneous Services. The $1.5 million in expenditures applies to Operations OM&A as noted in the interrogatory response at Exhibit H, Tab 13, Schedule 13.

f. Other Services – Miscellaneous Services has increased from $2.9 million in 2004 to $6.2 million in 2007. The increase can be attributed to the following factors:

- Third party switching requests have more than doubled between 2004 and 2007.
- Environment Health & Safety – A significant increase is attributed to supporting the company's achievement of strategic safety targets as described in Exhibit A, Tab 3, Schedule 1, page 2. Examples of specific initiatives include implementing a new e-learning system, developing a learning management system, improving an inventory of hazardous substances, and conducting pandemic planning.
- Other increases in various small programs that include joint use audits have contributed to the overall increase.

School of Energy Coalition (SEC) INTERROGATORY #5 List 1

Interrogatory

Ref: C1/T2/S2/pg 17 of 36, Sustaining OM&A – Lines – Line Maintenance

Preventative and Corrective Maintenance

Please complete the following table.

	2004	2005	2006	2007	2008
Reclosers (#) maintained					1850
Line Regulators (#) maintained					150
3 phase switches (#) maintained					150
Padmounted Transformers (#) maintained					500
Wash Insulators(#) maintained					8000
OM&A spending for the above 5 items ($Millons) [1]					**3.8M**
EPAC insulators replaced (#)					6500
Other insulators replaced (#)					3850
Other Defects (#)					9000
OM&A spending for the above 3 items ($Millons) [2]					**9.9M**
Total [1] + [2]	**7.2M**	**9.7M**	**12.3M**	**13.4M**	**13.7M**

Response

	2004	**2005**	**2006**	**2007**	**2008**
Reclosers (#) maintained	1,137	1,055	1,579	1,601	1,850
Line Regulators (#) maintained	93	53	114	153	150
3 phase switches (#) maintained	107	117	124	150	150
Pad mounted transformers (#) maintained	328	281	560	203	500
Insulator Washing	7,575	7,379	6,522	5,348	8,000
OM&A spending for the above 5 items ($ Millions) [1]	**$2.9M**	**$3.0M**	**$3.3M**	**$4.1M**	**$3.8M**
EPAC Insulators	5,549	7,031	7,242	3,683	6,500
Other insulators replaced (#)	794	2,727	2,909	5,804	3,850
Other Defects (#)	3,259	6,982	7,751	13,957	9,000
OM&A spending for the above 3 items ($ Millions) [2]	**$4.3M**	**$6.7M**	**$9.0M**	**$9.5M**	**$9.9M**
Total [1] + [2]	**$7.2M**	**$9.7M**	**$12.3M**	**$13.6M**	**$13.7M**

School Energy Coalition (SEC) INTERROGATORY #6List 1

Interrogatory

Ref C1/T2/S2/pg 25 of 36, Sustaining OM&A – Metering – Customer Retail Meters & Smart Meters

a. Please complete the following table.

	2004	2005	2006	2007	2008
Customer Retail Meters OM&A Spending ($Millions)	$8 M	$7.2 M	$8.1 M	$9.1 M	$6M
# retail meters					
Unit OM&A Cost – retail meters ($/retail meter)					
Smart Meter OM&A Spending ($Millions)	0	$2.4M	$4.9M	$8.8M	$9.7M
# Smart Meters in Service					
OM&A cost per meter smart meter					

Response

	2004	2005	2006	2007	2008
Customer Retail Meters OM&A Spending ($ Millions)	$8.0 M	$7.2 M	$8.1 M	$8.5 M	$6.0 M
# retail meters (see note 1)	*1,142,000*	*1,156,000*	*1,138,000*	*927,000*	*574,000 (estimated)*
Unit OM&A Cost –retail meters ($/retail meter)	*$7.00*	*$6.22*	*$7.11*	*$9.17*	*$10.45 (projected)*
Smart Meter OM&A Spending ($ Millions)	0	$2.4M	$4.9M	$8.8M	$9.7M
# Smart Meters in Service (see note 2)	*0*	*0*	*27,600*	*250,431*	*620,400 (estimated)*
OM&A cost per meter smart meter	*0*	*n/a*	*$175*	*$35.20*	*$15.65 (projected)*

Note:

1) Numbers for Retail Meters are total system Non-Smart Retail Meters at year end.
2) Numbers for Smart Meters in Service are total Smart Retail Meters Installed at year end.

School Energy Coalition (SEC) INTERROGATORY #7 List 1

Interrogatory

Ref: C1/2/2, pg. 27: Sustaining OM&A: Smart Meters

a. The evidence sets out the OM&A costs for smart meters associated with both minimum and incremental functionality. Please provide what portion of the 2008 budget of $9.7 million is related to each of the bulleted items listed. Where applicable, please provide the relevant unit cost and what assumptions Hydro One made regarding the number of units for 2008 (for example, the first bullet point on pg. 28 refers to one of the costs of incremental functionality as being caused by "responding to a higher number of customer inquiries as a result of pre- and post-installation of smart meters on customer premises"- what assumptions did Hydro One make regarding the increased number of calls and what was the cost per call?)

b. Pg. 28, lines 12-18: What assumptions did Hydro One make regarding the anticipated savings in other areas as a result of smart meter spending?

Response

a.

2008 OM&A Cost >Minimum Functionality	$K	Unit Cost Based on Cumulative Target to 2008 of 610,000 ($/Meter)
Maintenance on Billing System (TOU Capability)	554	0.91
Maintenance on Integration System	3,358	5.50
PMO	5	0.01
Total OM&A Costs Exceeding Minimum Functionality	3,917	6.42
2008 OM&A Cost for Minimum Functionality		
AMCC Maintenance	811	1.33
Telecommunication Charges	764	1.25
Smart Meters & Network Devices Maintenance	2,019	3.31
Call Handling, Billing and Customer Communication	1,151	1.89
Communication & Change Management	668	1.09
PMO	369	0.61
Total OM&A Cost for Minimum Functionality	5,782	9.48
Total 2008 OM&A Costs	9,700	15.90

The unit costs above have been all portrayed based on average unit cost per forecast cumulative installed meter.

Many of these costs will change over the life of the project, either as a result of the full implementation to 1.3 million meters, or as a result of changes in the customer demographics (for example as we move from higher to lower density) and geography / terrain (as we move from urban to rural and south to north).

The call handling component of the $1,151k is approximately $195k and is based on an assumption of 15% of customers call at a cost per unit of $14.

b. The meter reading savings forecast for 2008 is $1.4M, which is based on the following assumptions:

All systems tested and available for 25% of the year,
All of the 2007 (240k) and ½ of the 2008 (370k) available,
An average of 3.7 manual meter reads per year,
An average cost of $3.76 per manual reading $1.5M

An offsetting cost for EBT of $0.08 per read $(0.1)M

The savings in retail meter maintenance are based on a standing exemption from Measurement Canada for our meter sampling and reverification program for the majority of meters scheduled for testing in the 2008 to 2010 period. The savings come from lower field services costs (we no longer have to retrieve these meters) and lower sample testing costs. The savings forecast for 2008 is $2.8M and are based on the following:

		Avg. Cost	Number
Testing	Reverifiaction	17.11	5,762
	Sample	10.05	4,174
Field	S Base	145	6,947
	A Base	400	3,529

There is also approximately $400k of inventory savings.

School Energy Coalition (SEC) INTERROGATORY #8 List 1

Interrogatory

Ref: C1/2/2, pg. 29 and following: Sustaining OM&A: Vegetation Management

a. C1/2/2- Line Clearing: please provide the annual accomplishment (KM's of lines cleared) for 2004-2008.

b. Please provide the annual accomplishments for brush control for 2004 to 2008.

c. Please provide greater detail as to what the extra 15% (2008 budget of $7.9 million) in Customer Notification spending will accomplish and how specifically the extra funds will be spent.

d. C1/2/2, pg. 35- Table 10 shows the contribution of trees to system interruptions has been consistent for several years. Why wasn't the problem addressed sooner?

e. Asset condition assessment is generally completed 2 years prior to the time projected for line clearing. Information obtained includes vegetation height, tree and brush densities and clearances to conductors. The information is then used to schedule work. Please advise whether and to what extent the vegetation information gathered 2 years prior to the initiation of line clearing would be outdated in determining the priority of work.

Response

a. Please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 63.

b. Please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 63.

c. The 2008 budget for Customer Notification is approximately 15% above the historic average. The increase is attributed to Hydro One's plan for reducing the Vegetation Management cycle, which increases the Customer Notification requirements associated with the planned tree clearing and brush control accomplishments in 2008. The increase of roughly 20% in clearing accomplishments over historic average accounts for the increase in the 2008 Customer Notification budget.

d. Hydro One recognizes the large contribution that tree caused interruptions make to reliability performance and has for a number of years made concerted efforts to address the issue as communicated in both Hydro One's last rate application EB-2005-0378 and in the current rate application. In EB-2005-0378, Exhibit C1, Tab 2, Schedule 2, page 31, Hydro One discussed its efforts to address vegetation issues and

specifically noted the increase of line clearing accomplishments from 7,635 km in 2002 to 10,360 km in 2004, as well as its intent to increase line clearing accomplishments to a level of 12,500 km in 2008. Hydro One remains committed to this goal as evidenced by the 2007 line clearing accomplishment of 12,211 km. These long term efforts are the only way to address a wide spread and systemic issue such as tree caused interruptions and Hydro One anticipates reliability improvements as detailed in the interrogatory response in Exhibit H, Tab 1, Schedule 49 once shorter vegetation maintenance cycles are fully implemented.

e. Asset condition assessment (ACA) information gathered 2 years prior to scheduled vegetation maintenance is not considered outdated for the purposes of scheduling work. ACA information is utilized as soon as it is collected and Hydro One would not hesitate to schedule work on rights of way prior to the 2 year mark if ACA results identify an immediate need. It should also be noted that ACA information is one factor considered when scheduling work, along with other factors such as reliability performance, customer requests, and the volume of unplanned maintenance. As well, experience with rights of way and vegetation growth enables Hydro One to reliably project condition 2 years out from when the assessments were conducted.

School Energy Coalition (SEC) INTERROGATORY #9 List 1

Interrogatory

Ref: C1/T2/S2/Pg 34 & 35 of 36, Sustaining OM&A – Vegetation Management –Line Clearing, Brush Control

a. Please separately identify Line Clearing and Brush Control spending attributable to the 2006 summer storms.

b. The Line Clearing OM&A spending projected in 2008 of $77 million is about 45% over historical year average of $53 million. On page 34, it states that the increased spending was attributed to a volume increase of 35%. Does this also suggest an increase in the unit cost of 7.4%? Please explain any variation in the per-unit cost.

Response

a. Details on the expenditures attributed to the 2006 summer storms can be found in the response to the interrogatory in Exhibit H, Tab 13, Schedule 3, part b. Those expenditures are for forestry work that is required as a result of storm damage. Expenditures cannot be separated out by line clearing and brush control activities as Hydro One does not account for storm related costs in this manner.

b. The 2008 line clearing unit cost is $6,144 per km, is approximately 7.7% greater than the historic average (2004-2006) unit cost of $5706 per km. The variation in unit costs works out to approximately 2.5% per year and is largely attributable to escalation in labour costs.

School Energy Coalition (SEC) INTERROGATORY #10 List 1

Interrogatory

10. Ref: C1/2/3: Development OM&A

a. Please provide greater detail as to how the additional funding (in the amount of $2.4 million over the 2006 level) for Data Collection, Engineering and Technical Studies will be spent as well as how the $2.6 million in Standards and Technology will be spent. Please provide any cost-benefit analysis prepared to justify this additional spending.

b. Please provide the planned and actual spending for these items for 2006and 2007 and explain any variation.

c. Is the 2008 spending on these items impacted by HON having spent less than forecast in 2006? If so, how?

Response

a) The additional expenditure for 2008 over 2006 are as follows:

Data Collection and Engineering

- Increased analysis of the distribution system and data collection to ensure protections function as intended and are synchronized to ensure operating conditions remain within equipment ratings and address phase imbalance. These activities account for $1.1 million.
- Proactive feeder modeling for potential distributed generator connections $0.4 million.
- Long Term Load Transfer (LTLT) resolution with other LDCs $1.0 million.

Standards and Technology

- Technical review and approval to manage field modifications to comply with Ontario Regulation 22/04 issued under the Electricity Act, as well as the development of new construction standards. This accounts for an increase of $1.8 million from 2006 spending.
- Increase in the technology program to support distributed generation work, as well as support other standards work, and fund R&D projects through CEA Technologies Inc. - $0.7 million.

The cost benefits concerning this work is assessed through the prioritization process as outlined in Exhibit A, Tab 14, Schedule 5.

b)

	2006		2007	
	Actual ($M)	Planned ($M)	Actual ($M)	Planned ($M)
Standards and Technology	1.3	1.9	2.8	2.9
Data, Collection, Engineering and Technical Studies	2.8	2.9	5.2	5.2

The Standards and Technology program expenditures in 2006 were lower than plan as a result of delays in finalizing details on several R&D and standards projects due to a need for engineering staff to focus on other higher priority work.

c) No

School Energy Coalition (SEC) INTERROGATORY #11 List 1

Interrogatory

Ref: C1/T2/S3/pg 5 of 5, Development OM&A – Standards & Technology

Hydro One's Technology program provides the funding to monitor emerging technologies through its participation in industry interest groups. Projects were jointly funded with other utilities having similar interests or challenges.

a. Please identify the "other utilities" actively participated in the emerging technology interest groups, explain the joint expenditure sharing mechanism and the % share of the Technology program expenditures that are allocated to Hydro One.

b. On page 5, Hydro One states that reduced funding in Technology program would lead to increased longer term costs as opportunities to utilize emerging technologies would be missed. Please provide examples of major projects where the emerging technologies and/or new tools and methods funded by the Technology program were implemented.

c. Please provide examples of realized benefits (to quantify if possible) as a result of utilizing the emerging technologies and/or new tools and methods funded by the Technology program.

Response

a) Within the Electrical Power Research Institute (EPRI) leveraged R&D projects, there are many different utilities and organizations participating. Each project has its own set of participants. EPRI confirms that in 2007, Hydro One paid 17% of the costs of the EPRI projects in which it participated for both transmission and distribution.

With CEA Technology Inc. (CEATI), the Distribution Assets Life Cycle Management Interest Group (DALCM) is the largest interest group. There are approximately 30 utilities that participate. Hydro One's funding level varies from project to project, and is determined based on the level of interest of each utility. The percentage of funding within the group changes based on the type and number of projects under consideration and the level of interest by utility members.

b) Examples of projects, and their use of emerging technologies and/or new tools and methods include:

i) Communication alternatives for smart meters and distribution automation in remote areas without adequate land line networks were developed under this program.

ii) Resolving complexities concerning distributed generation. Specifically the investigation and analysis of alternatives surrounding transfer trip schemes and system modeling.

iii) Studies and R&D carried out under health and safety such as EFM allow Hydro One to implement policies and practices that are current and address public issues.

iv) Purchasing standards for transformer that allow evaluation of accurate life cycle costing.

c) Examples of realized benefits are provided below:

Configuration of Pole mounted transformers:
Hydro One replaces over 1,000 failed transformers a year. From these, about half have failed due to lightning. This project has provided the technical information to alter the design in order to improve lightning performance and reduce failures.

Transformer Loss Evaluation:
This project has provided the basis for assessing life cycle cost of transformer losses thereby improving investment decisions.

Communication Options for Hydro One's Distribution System
As part of our requirement to expand smart meters in rural areas we are also experimenting with new communication technologies such as WiMax for backhaul where other options do not exist. This technology has characteristics that would not only allow data transfer for meters, but also enable many of the applications associated with distribution automation and would support mobile IT initiatives.

EPAC Insulator Assessment
Laboratory and failure analysis of these insulators provided Hydro One the information needed to implement a replacement strategy that appropriately addressed reliability and safety risks.

School Energy Coalition (SEC) INTERROGATORY #12 List 1

Interrogatory

Ref: C1/T2/S3/pg 2 of 5, Development OM&A – Data Collection, Engineering and Technical Studies

Data collection and analysis of the distribution system, equipment and feeder operating characteristics are ongoing activities.

On page 3, Hydro One has identified 3 factors that caused a 100% increase of the Data Collection & Engineering spending, from historical average of $2.5 million to $5.4 million in 2007 and projected $5.2 million in 2008.

a. Please set out what studies Hydro One intends to undertake in 2008 and the cost of each.

Response

a. The studies Hydro One plans to undertake, and cost of each, are:

    1) Power quality, connection impact studies - $2.4 million
    2) Proactive feeder modeling for potential distributed generator connections $0.4 million.
    3) Long Term Load Transfer (LTLT) resolution with other LDCs $1.0 million.

School Energy Coalition (SEC) INTERROGATORY #13 List 1

Interrogatory

C1/2/4: Operations OM&A

a. Pg. 6: Operations OM&A: Operations- how was the 2008 budget for Operations ($9.5 million, up from $8.5 million in 2007 and down from $10.8 million in 2006) determined? What accounts for the $1 million increase from 2007 to 2008?

b. Operations OM&A- Operations Support- how was the 2008 budget for this program ($3.9 million, up from $2.6 million in 2007) determined? What accounts for the $1.3 million increase in expenditures from 2007 to 2008?

Response

a. The increase from 2007 to 2008 incorporates the hiring of new staff to address the current demographics of the operating discipline. Staffing levels are slightly above normal complement levels to provide for a training period for the new staff. In addition, this funding provides for slighter greater response during storm conditions than was experienced during 2007.

b. The actual spend for Operations OM&A- Operations Support for 2007 was $4.1 million. Hydro One has included $1.5 million associated with Distribution Operating Map and Station Operating Diagram Maintenance as part of the Miscellaneous Services as noted in the interrogatory response at Exhibit H, Tab 13, Schedule 4, part e. This amount should have been included as part of Operations Support for 2007. As such, there is no material difference in cost between 2007 and 2008.

School Energy Coalition (SEC) INTERROGATORY #14 List 1

Interrogatory

Ref: C1/2/5: Customer Care OM&A:

a. C1/2/5- please file a copy of the contract with Inergi LP.

b. How much of the $103.8 million budget for Customer Care OM&A is forecast to be paid to Inergi LP and how much represents internal HON costs?

Response

a. Hydro One Networks files a copy of the Outsourcing Agreement Contract with Inergi LP as Attachment A.

b. Of the $103.8 million budget for Customer Care in 2008, $40.5 (39%) million is forecast to be paid to Inergi, for services provided including billing, call handling, collections and settlements. In addition, the majority of Regulatory Compliance project spending of $3.6 million and a portion of the $2.6 million Service Enhancement spending is forecast to be paid to Inergi for project implementation services.

The internal HON costs represent $34.4 million of the Customer Care OM&A, and include meter reading, field disconnect or related orders, and a portion of customer care management. The balance of the Customer Care work program costs represent 3rd party services ($9.8 million) for items such as postage, telephone and bill remittance services, and bad debt ($13.0 million).

Attachment A

Outsourcing Agreement Contract
Inergi LP

Attachment A - Hydro One Networks redacted version of the Outsourcing Agreement Contract with Inergi LP available only in paper copy

The contract is available on request to –

Glen MacDonald – 416 345 5913
Anne-Marie Reilly – 416 345 6482

School Energy Coalition (SEC) INTERROGATORY #15 List 1

Interrogatory

Ref: C1/2/5: Customer Care OM&A- Base Services- Meter Reading

a. C1/2/5- how many customers are forecast to be on time of use bills in 2008?

b. Why are meter reading costs for 2008 forecast to be close to their 2007 level despite Hydro One's large smart meter expenditures in 2008?

c. What assumptions did Hydro One make regarding forecast savings in 2008 meter reading costs derived from the smart meter program?

Response

a) Approximately 140,000 customers would be on time-of-use billing according to our 2008 plan assumptions.

b) The 2008 meter reading costs are close to the 2007 level because 2007 spending was less than initial plan. The 2007 meter reading costs were less due to a change in staff compliment during 2007 to manage both the manual meter reading program as well as implementation of smart meters.

c) See IR response in Exhibit H, Tab 13, Schedule 7, b).

School Energy Coalition (SEC) INTERROGATORY #16 List 1

Interrogatory

Ref: C1/2/5: Customer Care OM&A- Base Services- Other Service Support Costs

a. Please provide a detailed explanation for the $1.2 million increase for this program from 2007 to 2008. How exactly will the extra funds be spent?

Response

As per Table 2 in the February 20, 2008 update to Exhibit C1, Tab2, Schedule 5 the Other Service Support Costs are increasing by $1.1M from 2007 to 2008.
The Other Service Support budget includes a number of contracts with 3rd parties, to provide services that support our billing, call handling and collection programs. The $1.1M increase breaks down as follows:

Collections related costs contribute $0.3M. Customer Care is making increased investments in collection activities. These activities include increased outbound call reminders to customers past due and an increase in expected collection agency fees.

Telephone costs contribute $0.2M. The telephone costs were lower in 2007, in part due to 2007 being a lower volume storm year. The 2008 spending is maintained at the 2006 level.

A $0.3M increase relative to 2007 is as a result of an adjustment in 2007 to write-off uncashed bill credits issued to customers.

A $0.2M increase in other 3rd party contracts.

School Energy Coalition (SEC) INTERROGATORY #17 List 1

Interrogatory

Ref: C1/2/5- Customer Care OM&A- Base Services- Customer Care Management

a. Please provide a more detailed explanation as to how each of the factors listed at C1/2/5, pg. 11 ("supporting the corporate objectives of improved customer satisfaction"; "refining management practices associated with the Inergi contract to assist in raising service quality to customers"; preparing for time of use billing related to the incorporation of smart meters") leads to an $3.1 million increase in this program from 2006 to 2008.

Response

Please see interrogatory response in Exhibit H, Tab 1, Schedule 66.

School Energy Coalition (SEC) INTERROGATORY #18 List 1

Interrogatory

Ref: C1/2/5: Customer Care OM&A- Regulatory Compliance

a. Explain why spending for this program was just $0.7 million in 2007, compared to $4.1 million in 2006 and forecast of $3.6 million in 2008. What functions were performed in 2006 and (forecast to be) performed in 2008? Why were these functions not performed in 2007?

Response

The Regulatory Compliance work is comprised of a number of discrete projects each year. Regulatory Compliance projects are required to implement Government and Regulator policies and policy changes, such as Bill 100, the seasonal RPP threshold change, or rate changes. As a result, Regulatory Compliance project spending varies year-over-year based on the number of regulatory and/or legislative policy changes that occur.

For example, in 2006, changes to business process and business applications were made to comply with the Distribution System Code (DSC) amendments regarding Security Deposits, the seasonal RPP threshold change and the 2006 Distribution Rate changes.

In 2007, there were fewer regulatory and legislative policy changes required. In addition, the work plan originally included preparation work for the Dx Rate Cost Allocation & Rate Design initiative, which did not materialize.

The 2008 Regulatory Compliance project plan includes the 2008 Dx Cost Allocation & Rate Design project, as well as the seasonal RPP threshold change. Further breakdown is provided in the IR response to Exhibit H, Tab 10, Schedule 15.

School Energy Coalition (SEC) INTERROGATORY #19 List 1

Interrogatory

Ref: C1/T2/S6/pg 13 of 82, OM&A Shared Services and Other – Common Corporate Costs – Finance – Treasury

a. Please update the reference on line 24: Distribution Portion of treasury costs charged to cost of debt

Response

Please note that the reference exhibit contained a minor error. The correct sentence should read: The Distribution portion charged to the company's cost of debt is $1.1 million in 2008, as shown in Exhibit B2, Tab 1, Schedule 2 Page 5, Line 28.

School Energy Coalition (SEC) INTERROGATORY #20 List 1

Interrogatory

Ref: C1/2/6: shared services costs

With respect to the shared services costs approved by the Board in Hydro One's 2007 Transmission rate application, the Shared Services OM&A for Hydro One Transmission for the 2008 test year was $57.1 million [Decision with Reasons in EB-2006-0501, pg. 19] please:

a. Provide an expanded Table 2 at C1/2/6 to show the total Shared Services OM&A approved by the Board in EB-2006-0501 [the 2007 Hydro One Transmission rate application] for the 2008 test year. Please include the total claimed for 2008 in EB-2006-0501 and the allocation to the Transmission business.

b. Please explain any discrepancies between the 2008 figure from the Transmission application and the 2008 figure in the current proceeding.

c. It appears that Customer Care was included under Shared Services and Other Costs in the Transmission proceeding but is not included in Shared Services and Other OM&A in the current application. Please explain.

Response

a) Table provided as requested:

Description	2008 Costs ($ millions)			
	Distribution Application (current) EB-2007-0681		Transmission Application EB-2006-0501 *	
	Total	Dx Allocation	Total	Tx Allocation
Common Corporate Functions	84.2	40.5	81.4	40.9
Asset Management	118.9	46.3	96.4	57.3
Information Management Services	99.3	52.6	95.6	43.9
Cost of Sales	11.5	5.9	17.4	9.9
Other Shared Services	(165.3)	(78.3)	(164.6)	(96.5)
Total	148.5	66.9	126.2	55.5

Table excludes Customer Care costs of $106.8 million Total and $1.6 million Tx Allocation

b) The Transmission application was filed in September 2006, and the Distribution application was filed in August 2007. The primary reasons for the plan over plan changes are as follows:

Common Corporate Functions: The increase in costs is primarily due to: new work requirements associated with transition to International Accounting Standards (IFRS) as required by the CICA and new internal control and regulatory requirements; increase in costs relating to Bill 198 and related testing of selected processes as required by OSC regulations; and a higher level of HR purchased contract services associated with increased HR transactions for additional staff.

Asset Management: Please see Interrogatory response Exhibit H, Tab 11, Schedule 19 part "b" for an explanation of the 2008 Asset Management spending level of $96.4M from EB-2006-0501 and the 2008 Asset Management spending level of $118.9M provided in this application

Information Management Services: The increase primarily relates to the impact of Capital Projects, specifically projected work primarily associated with the implementation of the Cornerstone project.

Cost of Sales: The reduction in cost of sales is primarily related to a reduction in the external work program.

c) The Transmission component of the Customer Care work program is very small and was included in the Shared Services and Other Costs in the Transmission submission as it did not warrant a separate section. The Customer Care work program is primarily Distribution-related, therefore it is identified separately in the Distribution application.

School Energy Coalition (SEC) INTERROGATORY #21 List 1

Interrogatory

Ref: C1/2/6: Shared Services: Comparison between Transmission and Distribution Applications

The following table shows the Shared Services costs in the current application as compared to the Shared services in the Transmission application.

	2007 Costs			2008 Costs		
Description	Distribution (current) application [C1/2/6, pg.4]	Transmission Application [EB-2006-0501, Ex. C1/2/5, pg.4]	Difference**	2008 costs: Distribution (current) application	2008 costs: Transmission application	Difference**
Common Corporate Functions	76.0	80.9	(4.9)	84.2	81.4	2.8
Asset Management	93.8	97.5	(3.7)	118.9	96.4	22.5
Information Management Services	98.2	98.2	0	99.3	98.7	0.6
Cost of Sales	Not available	18	N/a	11.5	17.4	(5.9)
Other Shared Services	Not available	(149.2)	N/a	(165.3)	($164.3)	(1.0)
Customer Care*	97.1	106.9	(9.8)	$103.8	$106.8	(3.0)
Total		244.0		252.3	236.4	15.9

*Part of Shared Services in Transmission application but listed separately in this application.

** Between 2007, or 2008 as the case may be, costs in Distribution application vs. costs in the Tx application.

Please:

a. confirm that the figures above from Hydro One's pre-filed evidence in EB-2006-0501 (the 2007 Transmission application) are correct. If not, please make the necessary corrections;

b. fill in the missing information in the table.

c. explain why 2007 Customer Care costs in the Transmission application were $106.9 million and 2007 Customer Care costs as stated in the current application are $97.1 million.

d. explain whether any portion of the 2008 Customer Care costs in the current application represent work, previously included in 2007 Transmission rates, deferred from 2007 to 2008.

e. explain why Common Corporate Functions, which were approved at 80.9 million for 2007 in the Transmission application, are stated at $76 million in the current proceeding.

f. explain whether any portion of 2008 spending in this proceeding represents expenditures deferred from 2007.

g. explain why the 2007 Asset Management function was $97.5 million in the Transmission application but $93.8 million in the current application.

h. Explain whether any portion of the 2008 spending for Asset Management represents expenditures, previously approved in the 2007 Transmission application, that were deferred from 2007 to 2008.

i. explain the differences in 2008 spending as between the amount stated in the Transmission application and that stated in the current application. In particular, please explain the $22.5 million difference in spending in Asset Management function (a 23.3% difference) as between the two applications. Please explain whether any portion of the difference in 2008 spending is due to spending deferred in 2007 and pushed to 2008.

j. In particular, please explain why 2008 System Investment spending went from $21.9 million in the Transmission application to $32.2 million in the current application.

Response

a) & b) Correct table as below

Description	2007 Costs			2008 Costs		
	Distribution Application EB-2007-0681 C1/2/6,	Transmission Application EB-2006-0501 C1/2/5, pg 4	Difference	Distribution Application EB-2007-0681 C1/2/6, pg 4	Transmission Application EB-2006-0501 C1/2/5, pg 4	Difference
Common Corporate Functions	76.0	80.9	(4.9)	84.2	81.4	2.8
Asset Management	93.8	97.5	(3.7)	118.9	96.4	22.5

	2007 Costs			2008 Costs		
Description	Distribution Application EB-2007-0681	Transmission Application EB-2006-0501		Distribution Application EB-2007-0681	Transmission Application EB-2006-0501	
Information Management Services	98.7	98.6	0.1	99.3	95.6	3.7
Cost of Sales	22.1	18.0	4.1	11.5	17.4	(5.9)
Other Shared Services	(111.2)	(157.9)	46.7	(165.3)	(164.6)	(0.7)
Customer Care	97.1	106.9	(9.8)	103.8	106.8	(3.0)
Total	276.6	244.0	32.6	252.4	233.0	19.4

c) In the Transmission application submitted in 2006, the Customer Care 2007 budget total was $106.9 of which $105.3M is attributable to Distribution and $1.6M to Transmission. In the Distribution application, the Customer Care 2007 actual program cost total of $97.1 million includes the Distribution portion of costs only, excluding the Transmission component. Taking into consideration Distribution costs only, the difference in 2007 budget versus actual costs is $8.2 million. The variance is primarily due to a reduction in meter reading costs due to a change in staff compliment during 2007 to manage both the manual meter reading program as well as implementation of smart meters; a reduction in Regulatory Compliance costs associated with a delay in implementation of the 2008 Distribution Rate Cost Allocation & Rate Design changes; and, reduced Customer Services Operations costs associated with lower than expected volume of calls due to fewer storms during 2007; partially offset by an increase in bad debt costs.

d) There is no material portion of the 2008 spending for Customer Care that represents expenditures that were deferred from 2007 to 2008.

e) The $76 million in the current proceeding reflects the 2007 actuals while the $80.9 million in the Transmission application is per the plan. The 2007 actuals are lower due to a number of factors, including lower OEB and consultant costs, lower labour costs in Corporate Finance associated with delays in hiring, lower claims and insurance, partially offset by higher Inergi HR costs associated with increased transactions, and higher external legal services.

f) There is no material portion of the 2008 spending for Common Corporate Functions that represents expenditures that were deferred from 2007 to 2008.

g) The $97.5 million of Asset Management spending in 2007 in EB-2006-0501 was a projected amount while the $93.8 million of Asset Management spending in this application is an actual amount. The $3.7 million difference is primarily due to the inability to hire up the planned level for 2007.

h) There is no material portion of the 2008 spending for Asset Management that represents expenditures that were deferred from 2007 to 2008.

i) Please see Interrogatory response Exhibit H, Tab 11, Schedule 19 part "b" for an explanation of the 2008 Asset Management spending level of $96.4M from EB-2006-0501 and the 2008 Asset Management spending level of $118.9M provided in this application.

j) Please refer to Interrogatory response Exhibit H, Tab 11, Schedule 19, part "b".

School Energy Coalition (SEC) INTERROGATORY #22 List 1

Interrogatory

Ref: C1/2/6, pg. 15: Shared Services

a. Please explain why Hydro One's self-insured insurance expense increases by $1.4 million in 2008 over 2007 (a 140% increase in one year) when other insurance premiums increase by about 4% ($5.3 million versus $5.1 million).

b. On page 40, the insurance costs increase in 2008 (over 2006) by $1.2 million due to cost escalation. Please confirm whether the insurance costs are for Hydro One's Property and Boiler and Machinery insurance as identified on page 41.

c. Please explain why insurance costs increase by $1.2 million in 2008.

Response

a. The self insurance expense for uninsured claims against Hydro One can vary significantly from year to year as a result of the number of claims against the company and the amount per claim. Hydro One's insurance premiums are more predictable on an annual basis provided the company realizes stable market conditions and a stable risk profile.

b. The insurance costs identified on page 41 are for Hydro One's Property and Boiler and Machinery Insurance premiums and associated costs.

c. The increase of $1.2 million from 2006 – 2008, is mainly related to higher premiums for Property and Boiler and Machinery insurance and also includes smaller increases to other costs.

School Energy Coalition (SEC) INTERROGATORY #23 List 1

Interrogatory

Ref: Exhibit C1/2/6, pg. 37-53- Shared Services OM&A: Asset Management Function

Pg. 41: with respect to the Distribution Rationalization function, please:

a. Describe:
   - the Distribution Rationalization plan,
   - the participants of the plan,
   - how the plan could assist Hydro One and other participating utilities improve efficiencies,
   - whether Hydro One has identified any areas in which efficiencies need to be improved.

b. explain what portion of the $9.6 million in Strategy and Business Development function is attributed to Distribution Rationalization.

c. explain how these activities are connected to the operation of the distribution system such that they should be funded by ratepayers.

Response

a.

- For a copy of Hydro One's Distribution Rationalization plan, see interrogatory response to Exhibit H, Tab 13, Schedule 1, part "b"
- The plan is solely for Hydro One
- The plan focuses on the efficiencies that Hydro One can realize when it takes over a Local Distribution Company (LDC) that is either electrically embedded in its distribution system or geographically surrounded by Hydro One's service territory
- Hydro One continually seeks opportunities for improving efficiencies. With respect to Distribution Rationalization, there are significant opportunities to eliminate duplication of back-office and overhead costs that exist in each LDC. When Hydro One takes over an embedded LDC it can incorporate the customers of the former LDC into its existing systems and processes without significantly increasing its centralized and overhead costs. This results in improved utilization of systems and processes and therefore improves productivity.

b. A small portion of the Strategy and Development budget (approximately $700,000) is related to internal staff dedicated to distribution rationalization and external advisors to develop transactions.

c. The Distribution Rationalization activities are expected to provide long-term benefits to ratepayers by spreading Hydro One's Distribution fixed costs over a broader base of customers once the acquired utilities costs are integrated into the rate making process. In keeping with the Report of the Board entitled "Rate-making Associated with Distributor Consolidation [July 23, 2007]", the cost savings achieved through the acquisition, resulting from efficiencies gained in operations, will be passed on to rate payers through lower rates for the consolidated entity once approval of the rate rebasing is attained (currently expected in 2011).

School Energy Coalition (SEC) INTERROGATORY #24 List 1

Interrogatory

Ref: C1/T2/S6/Pg 37, 40 of 82, OM&A Shared Services and Other – Asset Management Function – Strategy & Business Development

On page 37, the following Asset Management functions are identified: to develop an investment plan that ensures maintenance of critical distribution and transmission infrastructure to meet both the short and long term needs of customers and, to optimize by working with Hydro One's internal business units the bundling and sequencing of the work.

a. Please describe in detail Hydro One's investment plan for the next 5-10 years.

Response

This application only seeks approval for Hydro One's 2008 Revenue Requirement for its Distribution Business, which is detailed in the application.

Hydro One is not seeking approvals for years beyond 2008 as part of this application and therefore does not have Regulatory quality forecast information for years beyond 2008 to provide as part of this application process.

School Energy Coalition (SEC) INTERROGATORY #25 List 1

Interrogatory

Ref: C1/T2/S6/pg41 of 82, OM&A Shared Services and Other – Asset Management Function – System Investment Function

a. One of the factors contributing to the increased System Investment Function spending identified by Hydro One is the number of new proposed generation connections. Please provide the number of new generation connections over 2004-2006 and the respective spending in each year.

b. On page 43, GIS (Geographic Information System) has been identified as one of the new technologies that Hydro One will be testing and utilizing to provide a spatial representation of its physical assets. Please describe the current technology that will be replaced with the new GIS system, the estimated cost of the GIS system.

Response

a. The table below shows the forecast and actual generation projects/connections, as well as forecast and actual costs, for 2004 - 2006. Since the RESOP was launched in the fall of 2006, the forecast for 2006 does not include the expected impact of the RESOP. The table also shows information on Net Metering (NM) projects. The number of NM connected projects took an upward swing starting 2006 as a direct reflection of the change in NM regulation raising the threshold to 500 kW (from 50 kW).

The number of projects actually connected in a given year is driven by customer timelines and needs, which the LDC has little control over. It is also Hydro One's understanding that no Retail generators pursued connection in 2006 as a result of generation proponents waiting for the details of the Standard Offer Program to be finalized before moving ahead with their projects.

Year	Forecast / Planned (Budget)			Actual		
	Number of Projects		$ M	Number of Projects Connected (Total Capacity)		$ M
	Retail	Net Metering		Retail	Net Metering	
2004	16	6	0.9	1 (0.11 MW)	11 (0.13 MW)	0.2
2005	18	8	1.5	3[1] (13.6 MW)	10 (0.17 MW)	0.3
2006	14	12	1.3	0	36 (0.69 MW)	1.5

1) In addition, Hydro One did TS modifications to enable connection of 6 generators to another LDC system.

b) The GIS referenced on page 43 relates to System Investment staff involvement in, and direction of, the Asset Data Collection and Data Mart initiative that provides software to analyze information and allows information to be transferred and used in the corporate Geographic Information System (GIS) as noted in Exhibit D1, Tab 3, Schedule 5, page 29. The GIS provides spatial representation of Hydro One's assets that will eventually replace the existing maps in both hard copy and electronic form. System Investment has an interest in this information as it is used for work program development and planning, and as such, System Investment influences the data format and technologies used to collect and view information. The cost for this initiative is identified in Exhibit D1, Tab 3, Schedule 5, Table 6.

School Energy Coalition (SEC) INTERROGATORY #26 List 1

Interrogatory

Ref: C1/T2/S6/ pg 46 of 82, OM&A Shared Services and Other – Asset Management Function – Business Integration Function

The evidence states that work program standard costing rates have been developed by Hydro One, and Hydro One also performs analysis of the work program costs and results.

a. Please provide Hydro One's current and estimated work program standard costing rates, for the period 2004-2008, by each type of work program.

Response

Tables showing standard costing rates for 2004 – 2008 appear below.

	2004	2005	2006	2007	2008
PROVINCIAL LINES					
Regional Line Maintainer	98.50	92.00	91.00	103.50	111.00
Scheduling Tech (Grade 63)	94.00	92.00	91.50	108.50	117.50
Team Lead (Grade 62)	100.00	100.00	97.00	114.50	123.50
Field Business Clerk (Grade 56)	80.00	81.00	81.00	92.50	102.00
Supervising Tech (Grade 65)	107.00	101.50	102.00	118.00	126.50
Lines UTS II & III	111.00	105.50	104.00	116.00	124.50
Truck Driver	79.00	75.00	71.00	94.50	104.50
COSR (Grade 59)	85.00	85.00	83.00	100.00	113.00
MP 4	123.50	125.00	121.00	143.50	160.00
MP 2	110.50	112.00	100.00	127.00	142.00
Grade 64	106.00	105.50	104.00	116.50	131.00
Meter Reader UTS II & UTS III	135.00	119.00	125.00	95.00	97.00
Meter Reader A	0.00	79.00	74.50	84.00	86.00
Meter Reader B	65.00	55.50	54.00	56.00	57.50
Hiring Hall Labourer	36.50	39.50	43.00	49.50	55.50
Hiring Hall Foreperson	59.50	63.50	65.00	75.50	84.00
Hiring Hall Journeyperson	55.00	59.00	61.00	67.50	75.50
Hiring Hall Apprentices	40.50	44.50	45.00	52.50	58.00
Hiring Hall Meter Reader	47.50	46.00	41.50	45.00	46.50
Students	27.50	25.50	30.50	34.50	41.50

	2004	2005	2006	2007	2008
STATIONS					
Electrical Maintenance	108.50	103.50	97.00	107.00	118.00
Mechanical Maintenance	105.50	100.50	99.00	111.00	121.50
Civil Maintenance	104.50	99.50	87.00	105.50	117.00
MP2 / MP3	128.00	124.00	120.00	135.00	150.50
P&C (Tech) - PWU (Gr 65,66)	131.50	125.50	117.50	132.00	141.50
P&C (Technician) - PWU (Gr 64)	121.00	112.00	106.00	116.00	129.00
CMS Rigger	93.50	89.00	83.50	96.50	111.50
Clerk Grade 58	88.50	84.50	80.50	101.50	116.50
MP4 / MP5 / MP6	149.00	144.50	139.50	160.00	177.00
PWU (Grade 62, 63)	103.00	99.50	101.00	119.50	135.00
Hiring Hall Electrical Maintenance	63.50	67.00	70.00	71.50	79.00
Hiring Hall Labourer	51.50	55.00	57.50	67.00	74.50
Hiring Hall Apprentices	47.50	57.00	68.50	61.50	70.50
Hirig Hall Mechanical Maintenance	63.50	67.00	70.00	71.50	81.00
Hiring Hall Civil Maintenance	62.00	65.50	66.50	67.50	75.00
Student	42.00	38.50	41.50	51.00	59.00

	2004	2005	2006	2007	2008
FORESTRY					
Regional Maintainer Forestry	101.50	100.50	98.50	105.00	110.00
Forestry - UTS II	117.00	115.00	113.50	109.50	125.50
Forestry - UTS III	109.50	108.00	106.50	119.50	117.00
Forestry Technician	106.00	105.00	101.00	102.50	105.50
Labourers	74.00	74.50	86.00	76.00	80.50
Hiring Hall Apprentices	49.00	58.00	58.50	54.00	55.00
Hiring Hall Labourer	39.50	46.50	50.00	48.00	53.00
Hiring Hall Elec Forester Journyperson	52.00	60.00	62.50	58.50	64.50
Hiring Hall Senior Foreman	43.00	62.50	68.00	69.50	73.50

	2004	2005	2006	2007	2008
ENGINEERING					
MCP	202.00	190.00	179.50	161.50	150.00
MP 1	97.50	91.50	83.50	101.00	98.00
MP 2	104.00	97.50	86.00	117.50	114.50
MP 3	111.00	104.00	97.50	131.50	128.50
MP 4	118.00	111.00	104.50	143.00	140.00
MP 5	126.00	118.50	120.00	162.50	159.00
MP 6	134.00	126.00	127.50	159.50	156.50
PWU GR 56	62.00	58.00	53.00	86.00	83.00
PWU GR 58	70.00	65.50	62.50	100.50	97.50
GR 60 / 61	78.50	0.00	69.50	104.00	101.00
PWU GR 64	98.50	93.00	83.50	119.50	116.50
GR 65 / 66	111.00	0.00	88.00	130.50	127.00
CADD OP 61	73.00	75.00	71.50	97.00	94.50
CADD OP 63	93.00	84.00	82.50	112.50	109.50
CADD OP 66	111.00	100.00	96.00	124.50	121.50
NON REGULAR PWU	55.00	53.50	59.00	61.50	48.00
NON REGULAR CADD OPERATOR	79.00	76.50	69.50	72.50	65.00
NON REGULAR M&P	113.50	110.00	100.00	85.50	73.00

	2004	2005	2006	2007	2008
CONSTRUCTION					
MP4 Scheduling	94.00	92.00	90.50	0.00	0.00
Grade 64 Scheduling Technician	78.50	77.00	73.50	0.00	0.00
BTU - Groundman	59.50	0.00	59.50	59.00	61.00
BTU - Lineman	59.00	0.00	62.00	59.00	61.00
BTU - Foreman	69.50	68.50	71.50	67.50	69.50
BTU - Labourer	51.50	50.50	53.00	56.00	57.50
BTU - Carpenter	54.00	53.00	55.50	58.50	60.00
BTU - Operator	55.50	54.00	52.50	58.00	59.50
BTU - Iron Worker	63.50	62.50	61.50	61.00	63.00
BTU - Electrician	61.00	59.50	61.00	58.00	60.00
BTU - Teamsters	58.50	57.00	54.00	58.00	59.50
NON REGULAR PWU	78.00	75.00	68.50	46.00	48.00

Hydro One Networks Fleet Rates

Class Grouping	Description	2004	2005	2006	2007	2008
107	AUGER,UP TO 6' DIAMETER	75	65	75	100	102
118	UTILITY BOAT WITH INBOARD	20	35	35	55	56
119	WORK BOAT WITH INBOARD	40	40	40	55	56
139	LINE TENSIONER	20	20	30	50	51
141	LINE TENSIONER QUAD 2.5 TON	20	20	20	20	20
146	TRUCK MTD LINE PULLER TENSIONER	20	20	20	20	20
148	QUAD REEL STANDS	20	20	20	20	20
149	LINE PULLER TENSIONER,TRL MTD 11-20#	20	20	20	50	50
280	ALL TERRAIN CRANE				96	98
282	ROUGH TERRAIN CRANE 21-35 TON				80	84
285	ALL TERRAIN CRANE				100	100
340	DIESEL GENERATOR	5	5	5	5	5
396	SELF PROPELLED WORK PLATFORM >=25'	20	20	20	20	21
581	FELLER BUNCHER		100	15	15	28
594	MUSKEG TRACTOR 4 TON PAYLOAD	30	25	25	22	23
596	MUSKEG TRAILER 8 TON PAYLOAD	1	1	1	10	10
597	MUSKEG WITH RBD		125	110	150	153
598	MUSKEG WITH RBD (834)	55	55	55	86	88
607	BAKHO TRACTOR	20	10	15	15	15
629	ALL TERRAIN VEHICLE	8	8	8	8	8
641	FARM TRCT DSC MASSEY FERGUSON. 3600	55	55	55	55	55
642	FARM TRACTOR 70 HP	35	40	40	32	32
653	TRACKED VEHICLE 4 TON PAYLOAD	35	30	25	25	38
655	MUSKEG WITH AD (827)	90	90	100	125	141
658	CRAWLER LOADER 2 1/4 TO 4 CU YD	25	10	10	10	20
659	TRACKED CRAWLER/CARRIER	50	55	55	70	71
666	TRACKED CRAWLER 100 TO 120 HP	55	55	55	70	71
672	TRACKED CRAWLER 120 TO 150 HP	35	25	25	25	25
688	RUBBER TIRED TRACTOR WITH BAKHO	25	20	20	20	31
689	FARM TRACTOR WITH ATTACHMENTS	15	20	20	16	16
690	LOADER TRACTOR	10	10	10	15	15
693	TIMBERJACK/TREE FARMER	50	50	40	58	59
694	TREE FARMER(PHASING OUT)	20	50	50	45	45
696	BRUSH CUTTER RUBBER TIRED	59	60	60	54	54
697	TRACTOR MERI CRUSHER-LIGHT	50	50	80	102	104
698	FELLER BUNCHER TIMBERJACK 608S	90	110	110	110	110
699	SWING GRAPPLE TRACK SKIDDER			85	85	85

Class Grouping	Description	2004	2005	2006	2007	2008
702	TRACTOR FORKLIFT	12	12	12	14	15
845	INTERMEDIATE CAR	6	5	6	7	7
860	PERSONNEL CARRIER MISC	14	14	12	12	13
880	MISC VAN	20	15	15	11	12
881	CARGO VAN/PERS CARRIER 5-8 PASS	8	7	7	7	7
886	VAN W/25' AERIAL LADDER	20	15	15	15	19
890	PICKUP MISC	12	14	12	12	12
900	MISC SERVICE TRUCK	20	20	20	20	20
904	SERVICE TRUCK WITH AD (821)	20	10	20	20	34
907	SERVICE TRUCK WITH AD	50	45	40	50	45
913	14' STAKE TRUCK	20	15	20	21	21
916	STAKE TRUCK WITH RBD (831)	55	44	45	44	45
918	STAKE TRUCK W/ART CRANE	30	24	20	25	39
919	STAKE TRUCK WITH CRANE/RBD			40	25	39
920	FORESTRY TRUCK MISC	14	25	25	30	51
925	FORESTRY TRUCK WITH AD (822)	48	48	50	60	50
930	LINE MTNC TRUCK WITH 826		85	75	76	77
931	LINE MNTC TRUCK WITH 200ft AD	260	260	255	251	253
932	LINE MTNC TRUCK WITH AD	65	65	50	60	63
938	LINE MTNC TRUCK WITH RBD (832)	60	60	60	60	63
950	TRUCK TRACTOR W/SLIDING 5TH WHEEL	55	55	55	55	51
960	MISC	17	15	18	20	29
975	HOUSE TRAILER	2		5	5	5
976	HORSE VAN TRAILER			5	5	5
977	TRAILER, OIL FILTRATION	12	10	15	15	20
985	UTILITY TRAILER 11800 KG	7	7	7	7	12
986	LOW BED UTIL TRAILER 13-29 TON	11	11	12	12	17
988	LOW BED TRAILER 40 TO 50 TON	24	30	26	26	35
990	STORAGE TANK TRAILER	12	12	12	12	20
994	LOW BED FLOAT TRAILER 100 TON	18	5	7	7	11
995	TRAILER, DEGASSIFIER	10	5	5	5	13
	A STAR HELICOPTER	1,400	1,400	1,400	1,500	1,550
	LONG RANGER HELICOPTER	1,200	1,200	1,200	1,300	1,350

Material Surcharge Rates

	2004	2005	2006	2007	2008
Forestry	10%	10%	10%	10%	10%
Lines	16%	16%	12%	12%	14%
E&CS	5%	5%	5%	5%	5%
Stations	6%	5%	5%	5%	5%

1

Year-over-year variances in the material surcharge and loaded labour and equipment rates are explained by the following:

Labour:
A more challenging work program, and increased health and safety and regulatory requirements, have demanded increased supervisory, compliance and support staff.

Fleet
Generally our Fleet rates have remained constant over the 2004 - 2008 period. Some fluctuations have occurred because of the following:

1) a new class was created with no historical data;
2) a decision was made to keep older equipment rather than relegating them to surplus;
3) a minimal number of units per class (in some cases only one) have led to cost fluctuations year over year;
4) the utilization hours of equipment changes year over year.

Material Surcharge
Rates have remained relatively constant over the 2004 - 2008 period. While costs have increased in the Supply Chain Services function, an increase in purchase volume (the allocation driver) has allowed us to keep the rates at a consistent level.

School Energy Coalition (SEC) INTERROGATORY #27 List 1

Interrogatory

Within shared services, Finance costs increase from $22.3 million in 2006 to $26.9 million by 2008. The evidence [at C1/2/6, pg. 9] explains the increase as follows:

> The increase in costs in 2004 - 2008 are primarily attributed to the costs of complying with the requirements of Bill 198 on a continuing basis, as well as increased work requirements related to the Securities Commission and Provincial Audit issues.

a. Please provide a more detailed explanation for the increase in Finance costs. Specifically, what are the costs of complying with Bill 198 and what are the increased work requirements related to Securities Commission and Provincial audit issues. Please provide a breakdown of the additional costs from 2006 to 2008 including incremental staffing costs and external costs.

Response

The increase in Finance costs is primarily attributable to implementing new requirements associated with external changes in securities regulation related to internal control over financial reporting as well as the decision by the Canadian Accounting Standards Board (AcSB) to transition the accounting and reporting of publicly accountable enterprises to international financial reporting standards (IFRS).

These efforts to respond to emerging external requirements have increased the work load throughout Hydro One Networks, particularly within the Finance area. The compliance, financial reporting and regulatory finance units in the corporate finance function have seen the bulk of the increased workload. As a result, the Finance area has increased its staff between 2006 and 2008 and the associated labour and miscellaneous costs (e.g. material and supply costs) have increased. The costs of complying with the requirements in 2007 were approximately $1.8M and in 2008 are approximately $2.5M.

Bill 198 and Provincial Auditor

As Hydro One is a public securities filer, the passing of Bill 198, which is similar to the U.S. Sarbanes - Oxley Act, has required that the Company carry out extensive non-discretionary work to document and test internal controls to an extent that allows the CEO and CFO to certify the accuracy of Hydro One's publicly filed financial reports. These efforts, which are aimed at improving the quality and reliability of financial reporting and ensuring investor confidence in the integrity of the capital markets, have enhance already strong internal controls. In addition, Finance staff support the Company's response to the recommendations of the Provincial Auditor, again with a

resulting enhancement of internal control and increase in the stewardship of the Company's assets.

Specific to the Bill 198 initiative, resources are required to: assist with the execution and monitoring of the internal control plan; assist with the centralization, review, maintenance and archiving of policies and procedures on the internet; co-ordinate training across the organization on policies, procedures and processes; continue training efforts on the approvals process; lead the review of controls and processes over key areas such as miscellaneous revenues and receivables, procurement (including order desk), fixed assets, projects and programs, including variance approvals, inventory, and payroll; assist with the review of Inergi internal controls (i.e. SAS70 reports), including the updating of the Bill 198 flow charts to ensure user control considerations are functioning and fully documented.

Transition to IFRS

The AcSB has decided to require that publicly accountable enterprises transition from Canadian generally accepted accounting principles (based on the CICA Handbook's recommendations) to IFRS by 2011. Compliance with this requirement, again to meet the Company's obligations as a public securities filer, will require a major effort by Corporate Finance and other staff across the Company. The transition to IFRS will be highly complex and will require a detailed review of the accounting for each component of the financial statements. This will involve reassessment of the underlying accounting policies and procedures, review of the transactional accounting practices, and derivation of appropriate financial statement presentation and disclosure practices. There is also a requirement to integrate IFRS with the requirements of other internal and external stakeholders, to determine and implement system requirements, educate staff and ensure appropriate integration with existing regulatory accounting and Bill 198 control processes.

School Energy Coalition (SEC) INTERROGATORY #28 List 1

Interrogatory

Ref: A/8/3, pg. 7: Affiliate Services- Please explain the increase in fees, from $6.4 million in 2006 to $9 million on 2008 (a 40% increase in two years), paid by HON to Hydro One Telecom for Telecommunications Services.

Response

The increase is due to a number of factors, the most significant being the inclusion of costs related to labour and pension adjustments which Hydro One Telecom had previously absorbed and not passed on to Hydro One Networks. Other increases are due to costs associated with addressing NERC requirements; upgrading analog systems to digital; sustainment costs for new services added such as Virtual Private Network (VPN), Anti-Spam, and Bill 198 requirements; and upgrades to operating system support..

School Energy Coalition (SEC) INTERROGATORY #29 List 1

Interrogatory

Ref: A/8/3: Affiliate Services- Please explain the nature of telecommunications services provided by HON to Hydro One Telecom (in the amount of $195,000 in 2008, as per A/8/3, pg. 5, Table 1)

Response

Hydro One Networks provides the following services to Hydro One Telecom:

- Management of Telecom Services
- Data backbone, assets and lines for all users
- Voice backbone, assets and lines for all users
- Repairs, adds, and changes to telephones

School Energy Coalition (SEC) INTERROGATORY #30 List 1

Interrogatory

Ref: A/8/3, Affiliate Services

a. Appendix "A" (Hydro One Inc. service provision to Networks, Telecom, etc.), pg. 8: Please provide a breakdown of the $4.1 million in "President/CEO/Chairman Services" provided by Hydro One Inc. to Hydro One Networks in 2007.

b. A/8/3, Appendix "B" (Networks service provision to HONI, Telecom, etc.):
   i. Please provide details of the $180,000 in General Counsel and Financial Services provided by Networks to HONI;
   ii. Please provide details, including quantum and how costs is determined, of the $1.685 million in services provided by Networks to Telecom.
   iii. Please provide a copy of Hydro One Telecom's 2007 financial statements.

Response

a) Details of "President/CEO/Chairman Services" provided by Hydro One Inc. to Hydro One Networks in 2007:

HYDRO ONE COST DISTRIBUTION MODEL				**Assignment and Allocation of Dollars by Activity**		
Group	**Function or Service**	**Activities Performed**	**Cost Driver**	**$ Activity 2007 Budget**	**Transmission**	**Distribution**
HOI	Chair	Overall Assignment of Time	Non-energy Rev_Assets Blend	301,000	165,813	115,622
		General departmental expenses	Non-energy Rev_Assets Blend	25,000	14,109	9,838
HOI	Board	Overall Assignment of Time	Non-energy Rev_Assets Blend	0	-	-
		Audit Fee	Total Revenue_Assets Blend xBxTxR	697,529	324,253	373,276

HYDRO ONE COST DISTRIBUTION MODEL				Assignment and Allocation of Dollars by Activity		
		General departmental expenses	Non-energy Rev_Assets Blend	577,471	325,892	227,246
HOI	President/ CEO Office	Establish performance targets for safety, customer service, reliability	All Direct	107,700	58,158	47,388
		Provide strategic direction and manage the company to meet the targets of safety, customer service, reliability	All Direct	430,800	232,632	189,552
		Develop and maintain relationships with major customers and customer groups	All Direct	430,800	232,632	189,552
		Develop and maintain relationships with regulators, shareholder, lenders	All Direct	430,800	232,632	189,552
		Monitor, assess and remediate risks to operational and financial performance	All Direct	215,400	116,316	94,776
		Influence / Ensure company can adapt to changing regulatory framework and economic conditions	All Direct	430,800	232,632	189,552
		Plan for management succession	All Direct	107,700	58,158	47,388
		General departmental expenses	Pres_CEO Dept. Labor (Internal)	421,000	227,340	185,240
Total					2,220,567	1,858,982

b)

i. Details of 2007 General Counsel and Financial Services provided by Networks to HONI:

HYDRO ONE COST DISTRIBUTION MODEL					
Group	**Function or Service**	**Activities Performed**	**Cost Driver**	**$ Activity 2007 Budget**	**Share-holder Only**
Finance	Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	636,363	1,443
		Tax Planning	OperMaint Exp_Assets Blend	318,903	-
		Support Debt issuance	Total Debt	12,987	-

HYDRO ONE COST DISTRIBUTION MODEL					
		Special Projects	OperMaint Exp_Assets Blend	25,974	-
		Support regulatory filings	GC_Reg Dept. Labor (Internal)	18,759	-
		Support Construction activities	Capital Expenditures	20,202	-
		Other departmental activities	Tax Dept. Labor (Internal)	409,812	-
		Tax Consultants	Tax Dept. Labor (Internal)	150,000	209
		General departmental expenses	Tax Dept. Labor (Internal)	70,000	98
Finance	Financial Strategy	Support Regulatory Activities	All Direct	178,400	-
		Support Business Activities	All Direct	89,200	-
		Special Projects	All Direct	178,400	-
		Decision support for lines of business	All Direct	1,070,400	-
		DSM	All Direct	178,400	-
		Ontario Hydro Energy	All Direct	89,200	89,200
		General departmental expenses	Fin_Strat Dept. Labor (Internal)	300,000	15,000
Finance	Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	1,919,130	-
		Purchasing	Oper Maint Cap	189,210	-
		IMIT	Fin_IMIT Dept. Labor (Internal)	324,360	240
		Human Resources	HR Dept. Labor (Internal)	27,030	-
		Finance	Finance Labor Costs (Internal)	216,240	1,193
		Customers	Total Revenue	27,030	-
		General departmental expenses	IntAudit Dept. Labor (Internal)	80,000	42
Finance	Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	1,139,673	-
		Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager	446,706	-
		Support Asset Management activities and projects	Asset Manager	773,145	-
		Support Finance activities and projects	Finance Labor Costs (Internal)	750,237	4,140
		Provide operational support for Transmission and Distribution activities	Asset Manager	91,632	-
		Manage IT capital projects and IT strategy	Inergi IT (Internal)	1,672,284	-
		Support Inergi operations	Inergi IT (Internal)	721,602	-
		Other departmental activities	Fin_IMIT Dept. Labor (Internal)	131,721	97
		General departmental expenses	Fin_IMIT Dept. Labor (Internal)	334,000	247

HYDRO ONE COST DISTRIBUTION MODEL					
General Counsel	Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	5,011,000	50,110
		Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)	1,671,429	16,714
		General departmental expenses	GC_Law Dept. Labor (Internal)	128,571	1,286
Total					180,020

ii) Details of 2007 services provided by Networks to Telecom:

HYDRO ONE COST DISTRIBUTION MODEL					
Group	**Function or Service**	**Activities Performed**	**Cost Driver**	**$ Activity 2007 Budget**	**Telecom**
Corp. Services	Human Resources	Administer Compensation & Benefits Programs	FTEs	418,760	5,175
		Decision support	FTEs	518,060	6,402
		Staffing & Leadership- Recruitment, Hiring, Succession	FTEs	694,340	8,581
		Administer Pension Plan	FTEs	727,440	8,990
		Administer Inergi HR	Inergi HR (Internal)	209,380	2,588
		Consulting support to LOBs and corporate functions	FTEs	2,128,600	26,306
		Director	HR Dept. Labor (Internal)	372,420	4,602
Corp. Services	Labour Relations	Advice, guidance and training to LOBs under the Collective Agreements	FTEs	602,000	7,440
		Negotiate with Bargaining Units	FTEs	181,450	2,242
		Participate in grievance and arbitration filings	FTEs	485,150	5,996
		Participate in OLRB hearings	FTEs	120,400	1,488
		Internal vacancy management	FTEs	0	-
Corp. Services	Communic ations	Provide communications support for corporate safety program & activities	FTEs	427,700	-
		Provide communications support for customer information requirements	Direct Dx	1,119,050	-
		Provide Media Program for Community Info & Employee Contributions	FTEs	1,570,400	-
		Provide Support for Shareholder and External Stakeholder Relationships	Total Capital	855,400	-

HYDRO ONE COST DISTRIBUTION MODEL					
		Provide Support to CDM and Other Special Programs	Direct Dx	276,350	-
		Provide other internal communications support	FTEs	427,700	-
		Other departmental activities	Non-energy Rev_Assets Blend	850,400	7,762
		General departmental expenses	CorpComm Dept. Labor (Internal)	0	-
External Relations	External Relations	Support customer strategy, rate strategy, distribution generation strategy, benchmarking, external relations	Non-energy Rev_Assets Blend	1,004,513	-
		Develop working relationships with customers, regulators, shareholder, lenders	Non-energy Rev_Assets Blend	256,487	-
		General departmental expenses	Strategic Dept. Labor (Internal)	138,000	-
Corp. Services	Corporate Security	Provide Security Services for Company Assets	Assets	2,291,000	11,882
Corp. Services	Supply Mgmt Services	Manage warehouse facilities (incl. Inventory management)	Oper Maint Cap xBxTxR	2,500,000	-
		Warehouse (Provincial lines)	Oper Maint Cap xBxTxR	3,000,000	-
		Strategic Sourcing Initiative	Oper Maint Cap xBxTxR	31,250	-
		Supervise Inergi- SMS	Inergi SMS (Internal)	125,000	2,102
		Transportation	Oper Maint Cap xBxTxR	4,000,000	-
		Investment Recovery	Gross utility plant xBxTxR	200,000	-
		Inergi Inspection Project	Inergi SMS (Internal)	1,200,000	-
		Other departmental activities	Oper Maint Cap xBxTxR	93,750	-
		Purchasing	Oper Maint Cap xB	5,051,093	115,619
		Transportation	Oper Maint Cap xB	189,416	4,336
		Asset disposal and Investment recovery	Gross utility plant xBxTxR	378,832	-
		Strategic Sourcing Initiative	Oper Maint Cap xBxT	883,941	-
		Support management of warehouse facilities	Total Assets xBxTxR	631,387	-
		Other departmental activities	Inergi SMS (Internal)	675,331	-
Corp. Services	Corporate Services SVP	Manage all Corp Services Departments	Corp Svcs Group (Internal)	1,075,000	4,294
Finance	Corporate Controller	Accting policies; External reports; External audit / review	Non-energy Rev_Assets Blend	1,541,475	18,135
		Business Plan (incl. Financial Modeling & Analysis); Internal reports; Year-end projections	Non-energy Rev_Assets Blend	1,178,775	16,322
		Regulatory Finance Activities	GC_Reg Dept. Labor	770,738	6,045

HYDRO ONE COST DISTRIBUTION MODEL					
			(Internal)		
		Manage Inergi- General and Inergi-Finance contract	Inergi Finance_Total Blend (Internal)	0	-
		Revenue analysis and reporting	Total Revenue	438,263	-
		Monitor and support Financial systems and Corporate accounting	Total Revenue_Assets Blend	1,027,650	18,135
		Internal controls	Total Revenue_Assets Blend	408,038	10,579
		Other departmental activities	Contr. Dept. Labor (Internal)	680,063	4,679
		Actuarial consultants	FTEs	750,000	9,269
		Consultants- Bill 198 (Canadian SOX) compliance	Total Revenue_Assets Blend	0	-
		General departmental expenses	Contr. Dept. Labor (Internal)	200,000	2,580
Finance	Treasury	Liquidity Management, Debt Issuance and Financial Risk Management	Insurance Costs xB	208,800	2,544
		Insurance- Claims	Non-energy Rev_Assets Blend xB	3,112,308	35,679
		Fiduciary insurance policy	FTEs	55,091	681
		IT Costs	Total Capital	0	-
		General departmental expenses	Fin_Treas Dept. Labor (Internal)	527,801	6,380
Finance	Taxation	Compliance activities including tax filings and audits	OperMaint Exp_Assets Blend	636,363	47,811
		Tax Planning	OperMaint Exp_Assets Blend	318,903	12,987
		Support Debt issuance	Total Debt	12,987	179
		Special Projects	OperMaint Exp_Assets Blend	25,974	-
		Support regulatory filings	GC_Reg Dept. Labor (Internal)	18,759	-
		Support Construction activities	Capital Expenditures	20,202	-
		Other departmental activities	Tax Dept. Labor (Internal)	409,812	-
		Tax Consultants	Tax Dept. Labor (Internal)	150,000	8,853
		General departmental expenses	Tax Dept. Labor (Internal)	70,000	4,131
Finance	Financial Strategy	Support Regulatory Activities	All Direct	178,400	-
		Support Business Activities	All Direct	89,200	-
		Special Projects	All Direct	178,400	-
		Decision support for lines of business	All Direct	1,070,400	53,520
		DSM	All Direct	178,400	-
		Ontario Hydro Energy	All Direct	89,200	-

HYDRO ONE COST DISTRIBUTION MODEL					
		General departmental expenses	Fin_Strat Dept. Labor (Internal)	300,000	9,000
Finance	Internal Audit & Risk Mgmt	Audits	IntAudit TD Audits (Internal)	1,919,130	54,060
		Purchasing	Oper Maint Cap	189,210	4,217
		IMIT	Fin_IMIT Dept. Labor (Internal)	324,360	2,888
		Human Resources	HR Dept. Labor (Internal)	27,030	334
		Finance	Finance Labor Costs (Internal)	216,240	3,776
		Customers	Total Revenue	27,030	206
		General departmental expenses	IntAudit Dept. Labor (Internal)	80,000	1,938
Finance	Info Mgmt & Info Technology	Support to backbone, PCs and applications; Support internal telecommunications	Workstations	1,139,673	13,078
		Develop systems required by operating businesses to meet changes in technical, operating and regulatory requirements	Asset Manager	446,706	-
		Support Asset Management activities and projects	Asset Manager	773,145	-
		Support Finance activities and projects	Finance Labor Costs (Internal)	750,237	13,099
		Provide operational support for Transmission and Distribution activities	Asset Manager	91,632	-
		Manage IT capital projects and IT strategy	Inergi IT (Internal)	1,672,284	16,516
		Support Inergi operations	Inergi IT (Internal)	721,602	7,127
		Other departmental activities	Fin_IMIT Dept. Labor (Internal)	131,721	1,173
		General departmental expenses	Fin_IMIT Dept. Labor (Internal)	334,000	2,974
General Counsel	Law	Overall Assignment of Time	Non-energy Rev_Assets Blend	5,011,000	50,110
		Consultants and External Legal Counsel	GC_Law Dept. Labor (Internal)	1,671,429	16,714
		General departmental expenses	GC_Law Dept. Labor (Internal)	128,571	1,286
Telecom Services	Telecom Services	Management of Telecoms Services	Telecom Services	3,178,000	37,812
		Data backbone, assets and lines for all users	Workstations	4,832,030	55,450
		Voice backbone, assets and lines for all users	Telephones	3,849,400	46,678
		Repairs, adds, changes to telephones	Telephones	5,102,800	61,877

HYDRO ONE COST DISTRIBUTION MODEL					
Inergi	ETS - Applications Support	Support CSO Applications	Inergi CSO (Internal)	6,732,405	-
		Support Finance Applications	Inergi Finance (Internal)	4,488,270	113,135
		Support HR Applications	Inergi HR (Internal)	3,590,616	44,373
		Support Passport Applications	ProgramProjectCosts	3,141,789	-
		Support Market Ready Applications	Market Ready	7,142,298	-
		Support Telecommunications Infrastructure	Telephones	1,346,481	16,328
Inergi	ETS - Infra-structure Svc. / Misc. Apps	Supply Management Services	Inergi SMS (Internal)	3,477,265	58,463
		Direct Assignments	All Direct	1,014,964	-
		General Infrastructure Support	Non-energy Rev_Workstations Blend xB	21,090,911	281,511
Inergi	Customer Support Operations	Inbound calls / correspondence	All Direct	21,549,402	-
		Bill Production	All Direct	9,500,274	-
		Data Services- Timesheets for field personnel, Tx operations	All Direct	3,089,520	-
		CSO Support- Management; Training, Communications, Support; Application support Business Analysts	All Direct	4,479,804	-
Inergi	Settlements	Wholesale and Retail Settlements	All Direct	3,000,000	-
Inergi	Finance	Accounts Payable processing	Invoices To Vendors	1,828,262	61,719
		Accounts Receivable processing	Other Bills To Customers	1,367,043	105,988
		Fixed Assets processing	Gross utility plant xB	655,035	4,072
		Corporate accounting, Budgeting, Analysis	Non-energy Rev_Assets Blend xB	5,387,497	61,761
		Pension support	FTEs	53,193	657
		Inergi Corp. Finance	Inergi Total (Internal)	1,038,970	8,923
Inergi	HR - Pay Services	Payroll Services and Recordkeepping	FTEs	3,481,000	43,019
Total					1,684,572

iii) Hydro One Telecom's 2007 financial statements are outside the scope of this proceeding.

School Energy Coalition (SEC) INTERROGATORY #31 List 1

Interrogatory

Ref: C1/T3/S2/pg 1 of 11
a. Please complete the following table, and also provide similar results for 2004-2007.

2008 Test Year	HC	Over time (Hr)	Base ($M)	Overtime ($M)	Incentive ($M)	Other ($M)	Total Wages ($M)	Avg Overtime Pay ($/Hr)	Avg Base Pay ($/HC)	Incentive Pay as % of Base
PWU										
Society										
Management										
Total Regular										
PWU										
Society										
Management										
Total Temporary										
Casual Workers										
Contract Staff	(to provide rates by type or work program or skill sets									
Total			$406.4	$72.1	$8.5	$21	$508			

Response

See attached table (Attachment A).

As noted at Exhibit C1, Tab 3, Schedule 1, Page 1, "Hydro One utilizes a work-based approach to staffing, whereby the Company resources according to work programs rather than plans the work around the number of internal resources available". Consequently, the requested information for the forecast year 2008 is not available by employee group but is provided in total.

($)

2004

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay $/hr	Average Base Pay	Incentive as % of Base
PWU-Reg	2681	230,045,641	178,218,409	644,413	39,305,550	6,459,964	6,061,718	60.99	66,475	3.62%
SOCIETY-Reg	878	82,198,171	74,053,545	83,556	6,142,453	170,421	1,831,752	73.51	84,343	0.23%
MCP-Reg	282	36,784,377	29,215,362	666	54,255	5,680,469	1,834,291	81.46	103,601	19.44%
Total Regular	3841	349,028,188	281,487,316	728,635	45,502,257	12,310,854	9,727,761	62.45	73,285	
PWU-Temp	89	2,865,597	2,791,567	3,567	171,011	5,127	-102,108	47.95	31,366	0.18%
SOCIETY-Temp	57	2,898,013	2,897,882	1,474	87,696	0	-87,565	59.49	50,840	0.00%
MCP-Temp	5	119,859	120,134	22	561	0	-837	26.09	24,027	0.00%
Total Temp	151	5,883,469	5,809,583	5,062	259,267	5,127	-190,509	51.22	38,474	
CASUAL	881	49,320,165	36,435,452	141,728	7,441,792	0	5,442,921	52.51	41,357	0.00%
TOTAL	**4,873**	**404,231,822**	**323,732,351**	**875,425**	**53,203,316**	**12,315,981**	**14,980,173**			

2005

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU-Reg	2741	237,735,189	188,352,797	653,403	40,981,168	2,658,425	5,742,799	62.72	68,717	1.41%
SOCIETY-Reg	851	57,430,393	52,036,315	31,994	2,409,218	47,424	2,937,437	75.30	61,147	0.09%
MCP-Reg	312	41,021,983	32,331,641	1,926	144,251	5,676,201	2,869,889	74.88	103,627	17.56%
Total Regular	3,904	336,187,565	272,720,753	687,323	43,534,637	8,382,050	11,550,125	63.34	69,857	
PWU-Temp	58	1,876,779	1,745,586	3,186	158,682	2,610	-30,099	49.81	30,096	0.15%
SOCIETY-Temp	31	1,507,881	1,434,783	552	31,546	0	41,552	57.20	46,283	0.00%
MCP-Temp	10	315,086	305,778	92	3,507	0	5,800	38.08	30,578	0.00%
Total Temp	99	3,699,746	3,486,147	3,829	193,735	2,610	17,254	50.60		
CASUAL	1075	57,999,463	44,925,186	138,361	6,917,500	0	6,156,777	50.00	41,791	0.00%
TOTAL	**5,078**	**397,886,774**	**321,132,086**	**829,514**	**50,645,872**	**8,384,660**	**17,724,155**			

2006

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU-Reg	2862	262,294,356	202,358,005	817,428	53,457,558	4,200	6,474,593	65.40	70,705	0.00%
SOCIETY-Reg	687	65,175,105	62,356,208	18,056	1,466,238	0	1,352,659	81.20	90,766	0.00%
MCP-Reg	469	59,489,433	49,471,987	703	55,767	4,397,964	5,563,716	79.33	105,484	8.89%
Total Regular	4,018	386,958,894	314,186,200	836,187	54,979,563	4,402,164	13,390,968	65.75	78,195	
PWU-Temp	110	2,509,937	2,582,255	1,869	111,845	0	-184,162	59.86	23,475	0.00%
SOCIETY-Temp	45	1,269,193	1,336,917	238	19,831	0	-87,555	83.50	29,709	0.00%
MCP-Temp	7	218,523	215,324	26	1,165	0	2,035	45.67	30,761	0.00%
Total Temp	162	3,997,654	4,134,495	2,132	132,840	0	-269,682	62.32		
CASUAL	1121	68,368,828	49,638,768	217,109	11,375,466	0	7,354,595	52.40	44,281	0.00%
TOTAL	**5,301**	**459,325,376**	**367,959,463**	**1,055,427**	**66,487,869**	**4,402,164**	**20,475,881**			

2007

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU-Reg	3,084	276,571,977	226,331,027	720,130.55	48,126,236	500	2,114,215	66.83	73,389	0.00%
SOCIETY-Reg	712	67,398,484	65,268,684	29,058.80	2,332,197	6,500	-208,898	80.26	91,670	0.01%
MCP-Reg	516	67,420,494	56,665,378	799.50	63,511	6,636,752	4,054,852	79.44	109,817	11.71%
Total Regular	4,312	411,390,956	348,265,090	749,988.85	50,521,944	6,643,752	5,960,170	67.36	80,766	
PWU-Temp	143	2,826,419	3,116,973	1,060.25	50,825	0	-341,379	47.94	21,797	0.00%
SOCIETY-Temp	92	3,019,335	3,350,706	303.00	19,862	0	-351,234	65.55	36,421	0.00%
MCP-Temp	8	297,149	290,565	0.00	0	0	6,584	0.00	36,321	0.00%
Total Temp	243	6,142,903	6,758,244	1,363.25	70,687		-686,029	51.85	27,812	
CASUAL	1338	77,992,251	59,693,098	189,603	10,343,821	0.00	7,955,332	54.56	44,614	0.00%
TOTAL	**5,893**	**495,526,109**	**414,716,432**	**940,955**	**60,936,452**	**6,643,752**	**13,229,473**			

2008

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime Hours Worked	Overtime(Incl Premium)	Incentive	Other	Average Overtime Pay	Average Base Pay	Incentive as % of Base
PWU Reg										
SOCIETY Reg										
MCP Reg										
Total Reg										
PWU Temp										
Society Temp										
MCP Temp										
Total Temp										
CASUAL										
TOTAL	**7079**	**580,700,000**	**475,500,000**		**72,100,000**	**8,500,000**	**24,600,000**		67,171	1.79%

Note: Average Base Pay for Non-Regular employees are not meaningful because the period of employment could be significantly less than 1 year.
Other includes: Travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowances, vacation pay on termination, sick leave pay

School Energy Coalition (SEC) INTERROGATORY #32 List 1

Interrogatory

Ref: C1/T4/S1/pg 1 of 9, Costing of Work

a. Please provide Hydro One's standard material surcharge, loaded labour and equipment rates, for the period 2004-2008, and explain the year over year variation.

Response

Please see the Interrogatory response at Exhibit H, Tab 13, Schedule 26.

School Energy Coalition (SEC) INTERROGATORY #33 List 1

Interrogatory

Ref: C2/3/1, pg. 3: Please explain the increase in incentive pay for Managers from an average of $3,139 in 2006 to an average of $11,600 in 2008.

Response

Hydro One incentive payments for management staff are paid in January and are based on performance in the preceding year. The chart reflects the incentive payments in the year that the payments are received. For the 2006 calendar year a significant number of new management staff were hired. Given these staff were new to management they did not receive any incentive payments in 2006. This resulted in the 2006 incentive payment being disproportionably low on a per capita basis. In 2008, the staff hired into management in 2006 are eligible for incentive payment. This results in the increase in the incentive payment in 2008.

School Energy Coalition (SEC) INTERROGATORY #34 List 1

Interrogatory

The "Report of the Agency Review Panel on Phase I of Its Review of Ontario's Provincially-Owned Electricity Agencies", the Agency Review Panel set out a number of recommendations (at pg. 20-24 of the report) for determining executive pay at publicly-owned electricity agencies in Ontario. Please explain what steps Hydro One has taken to implement these recommendations.

Response

Hydro One has accepted the recommendations of the Arnett Panel regarding executive compensation. The top five Executive positions at Hydro One will have their compensation altered as the incumbents leave in order to follow the guidelines recommended by the Arnett Panel. The target compensation for these positions was arrived at following a compensation study consistent with the Arnett Panel recommendations.
This study utilized a comparator group of 30 companies; 15 public sector and 15 private sector, and comparisons were made with the 50% percentile of the Total Direct Cash of these companies. Two positions - the CEO and General Counsel - have already had their compensation reduced.

With respect to other recommendations made by the Arnett Panel:

1. "Perks" from senior executives compensation have been eliminated.
2. The Human Resources Committee of the Board does consist of members with human resources compensation and finance expertise.
3. The compensation of our most senior executives is currently disclosed in our Annual Information Form which is provided to the Canadian Securities Administrators and published on the SEDAR website.
4. Hydro One reporting is consistent with the requirements of the Canadian Securities Act. The Agency Review Panel recommendations assumed that certain provisions of the Act would change in 2008, and that Hydro One should report in a manner consistent with the changes. However, when the changes were not approved, Hydro One reported against the existing requirements. If and when the requirements change in 2009, Hydro One will report consistently against them.

School Energy Coalition (SEC) INTERROGATORY #35 List 1

Interrogatory

Exhibit A/15/2, Attachment "B": Hay Group benchmarking report. At pg. 7 of the report, Hay Group explains the adjustment methodology used to adjust the wage rates of the comparator companies to match the skill level of Hydro One's job classifications. The adjusted maximum hourly wage= the number of Hay Points for the comparator company's job times the wage rate per point. It appears from the example used that the wage rate for the "Client" (i.e. the company that is the subject of the study) is not adjusted, so that the Client's unadjusted wage rate is compared to the comparator company's adjusted wage rate. Please explain.

Response

Under the methodology used to compare similar jobs to the client's jobs (Hydro One), only the comparator jobs require an adjustment to account for Hay point differences amongst the matched jobs.

This adjustment is required since each comparator job has a different Hay point value – in the example at page 7 of the Report, one job has a Hay point value in excess of the Hydro One job and the 4 other examples have a Hay point value less than Hydro One's job. The 'wage rate per Hay point assigned' is multiplied by the client's Hay point value in order to make this adjustment (eg. 'Participant A' **0.107** Max Hrly Wage Rate Hay Points Assigned x **510** Hydro One Hay Points= **54.61**).

School Energy Coalition (SEC) INTERROGATORY #36 List 1

Interrogatory

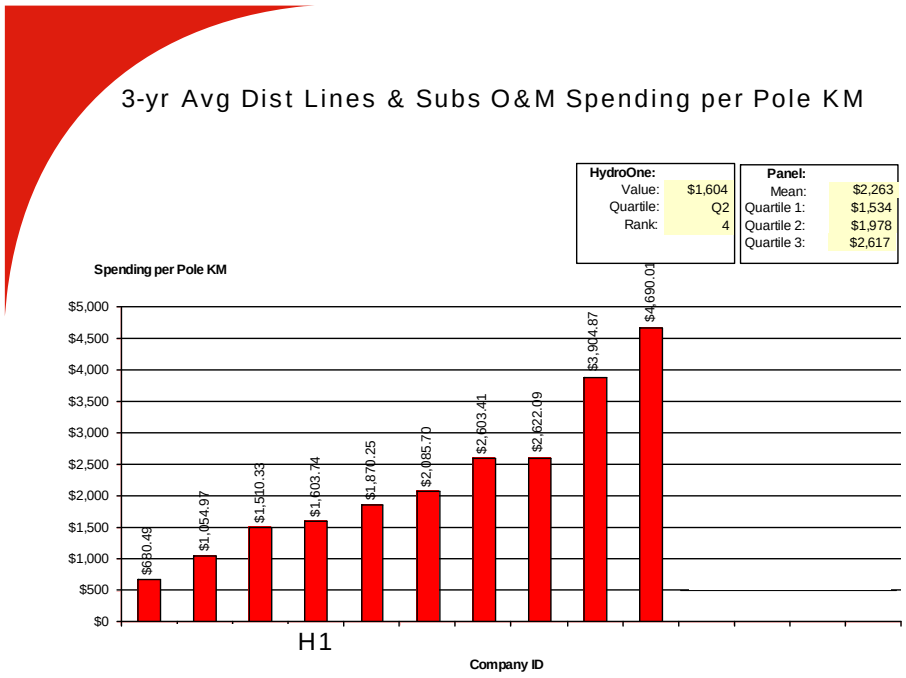
Exhibit A/15/2, Attachment "A" PA Consulting Benchmark Report

a. did PA Consulting use total OM&A (per customer, per line km, etc.) as a benchmark? Why or why not?
b. If available, please provide the total OM&A per customer for Hydro One and the comparator utilities.
c. PA says, at pg. 3-13, that the fact that Hydro One's costs on a per customer basis are at the high end of the sample are the result of Hydro One's low customer density. However, at pg. 3-13, PA says that the comparator utilities were chosen partially on the basis that they have customer densities of less than 30 customers per square KM. Did PA compare Hydro One's customer density to that of the comparator utilities?
If so, please provide it.

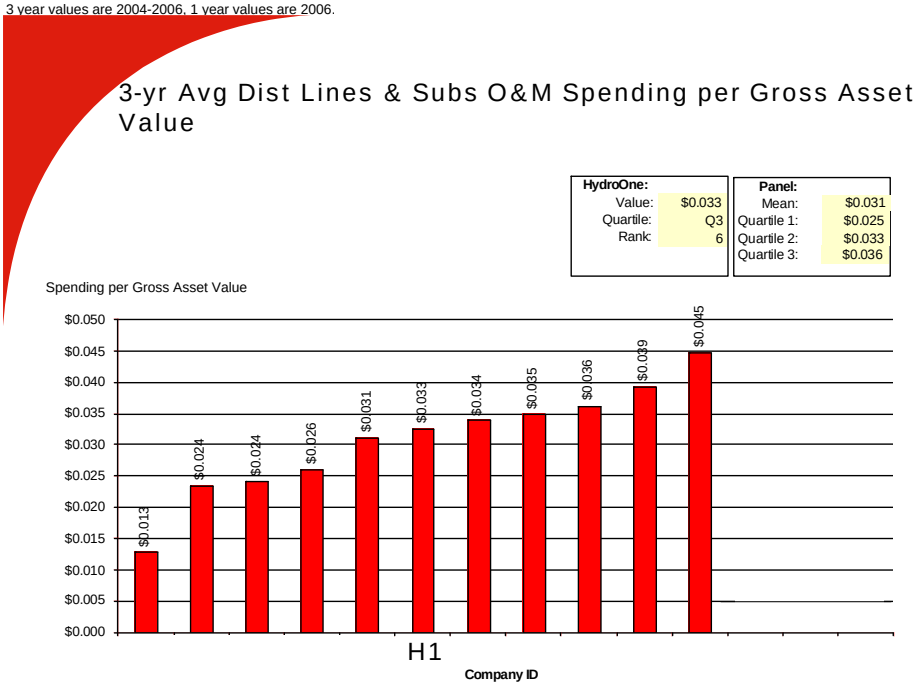
Response

a. No, PA Consulting did not use total OM&A (per customer, per line km, etc) as a benchmark. PA Consulting looked at specific operating and maintenance expenses (O&M total) per customer, per line km, and per other normalizing variables as benchmarks. O&M costs were included in the comparisons because these are a well defined and significant component of the overall costs for a distribution company, and a "standard" metric used in distribution benchmarking studies across the industry. The benchmark excludes administrative and general expenses. The graphs showing the results were provided as Appendix C to the PA report.

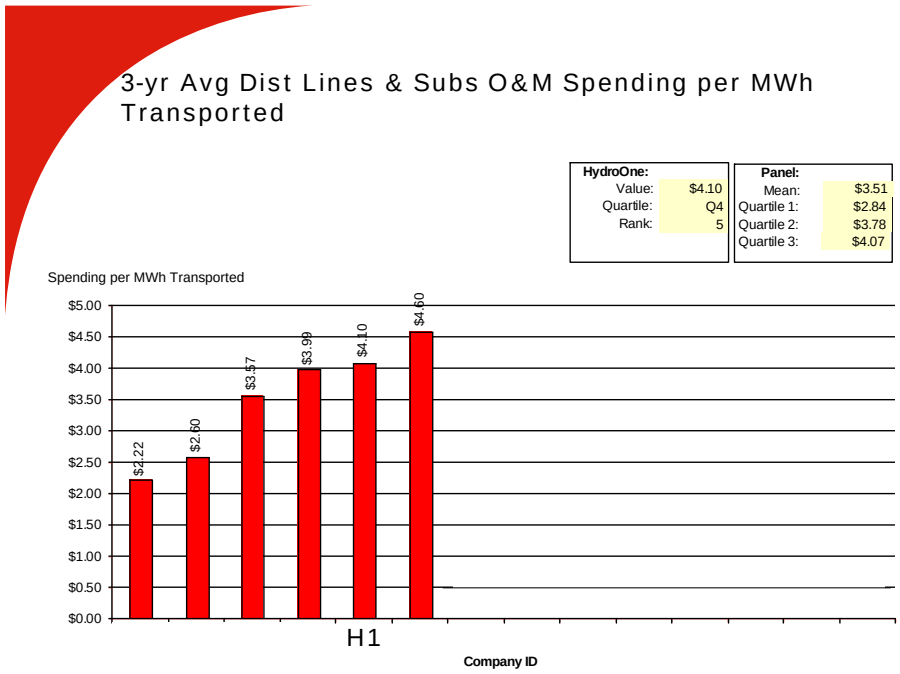
b. The charts below, taken from the Appendix to the PA report, provide the comparisons using total O&M costs.



1 3 year values are 2004-2006, 1 year values are 2006.

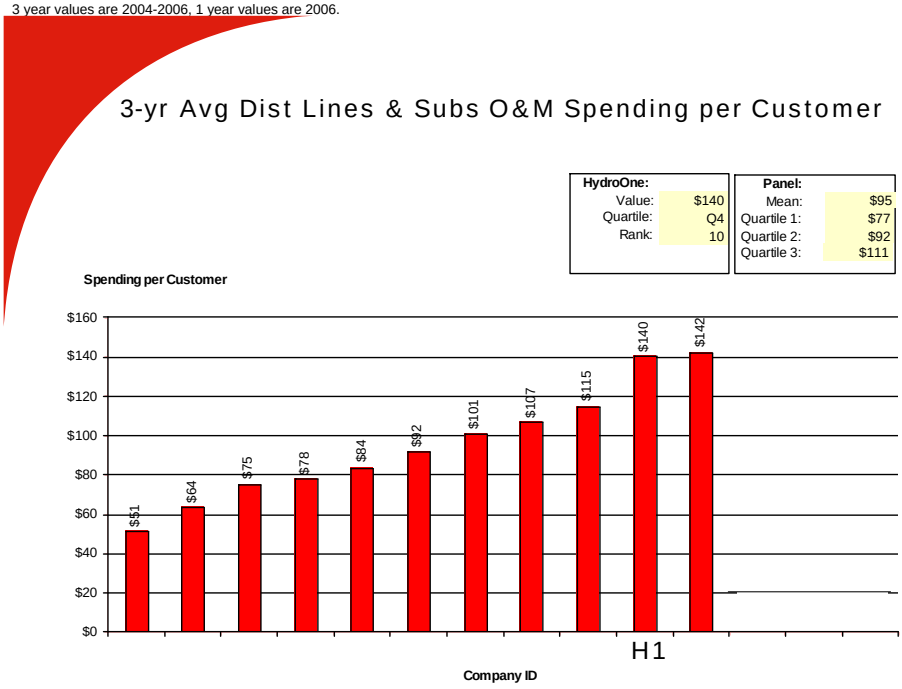


2 3 year values are 2004-2006, 1 year values are 2006.



C-11

3 year values are 2004-2006, 1 year values are 2006.

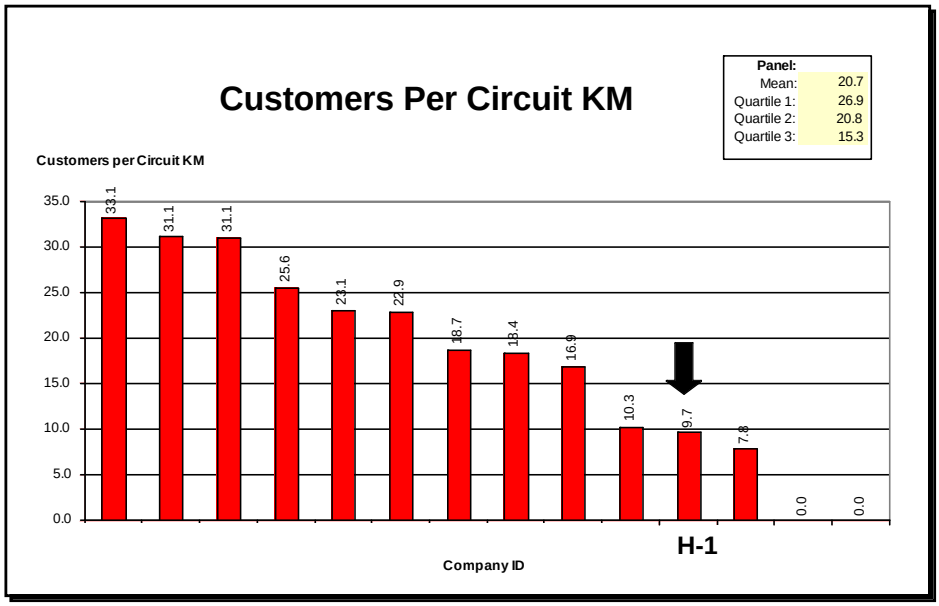


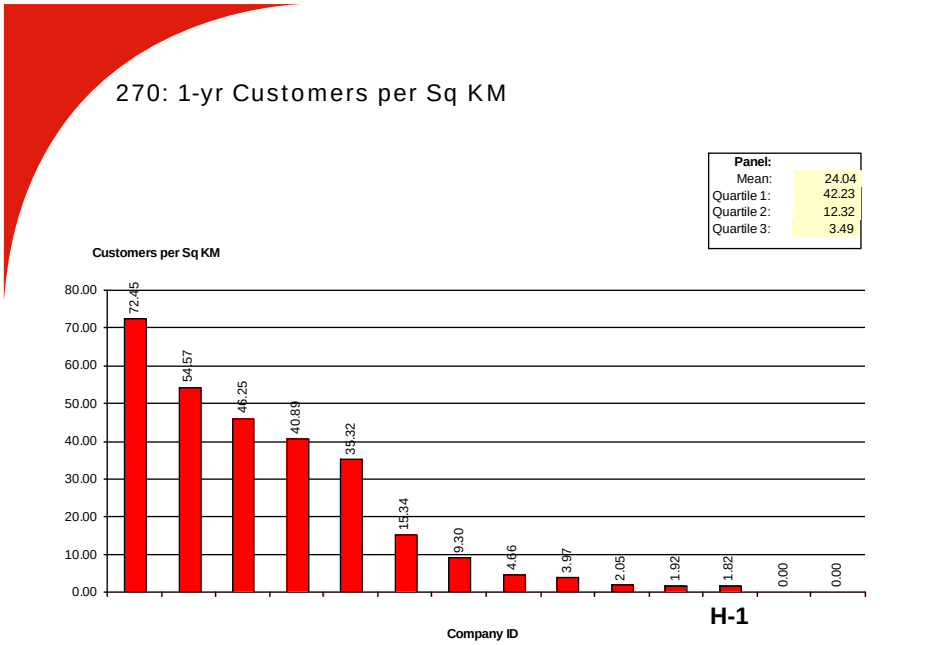
C-14

3 year values are 2004-2006, 1 year values are 2006.

c. While it is true that the comparator companies were chosen because of their relatively low density in comparison with other utilities across North America, even these comparator companies have higher density than Hydro One, with one exception. The

charts below show the density of the comparator utilities compared and Hydro One. Hydro One is at the low end of the density spectrum on the basis of both customers per circuit km and customers per square km.





School Energy Coalition (SEC) INTERROGATORY #37 List 1

Interrogatory

A/9/1, Attachment 2, pg. 10 (December 31, 2005 financial statements): please provide details of any interest rate swap contracts Hydro One has entered into since 2005.

Response

Hydro One periodically uses interest rate swap contracts to manage interest rate risk. Hydro One may enter into derivative agreements, such as forward start interest swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements.

No interest rate swap agreements were entered into during 2006.

During August and September 2007 Hydro One entered into 10 year forward start interest rate swap agreements having a total notional principal amount of $200 million. These swap agreements were terminated in October 2007, at the time Hydro One actually completed a 10 year debt issue.

During late 2007 and early 2008 Hydro One entered into 10 year forward start interest rate swap agreements having a total notional principal amount of $200 million. These swap agreements were terminated in March 2008, at the time Hydro One actually completed a 10 year debt issue.

School Energy Coalition (SEC) INTERROGATORY #38 List 1

Interrogatory

A/14/3, pg. 5: the evidence states, at line 11, that "Hydro One Distribution CDM plans, which have a direct impact on distribution system energy demands" were taken into consideration in developing Hydro One's load forecast. Please provide more detail as to how CDM activity was taken into account in Hydro One's load forecast.

Response

As presented in Table 4 in page 20 of Exhibit A, Tab 14, Schedule 3, CDM activities are treated as a reduction in load in Hydro One's load forecast. Please note there was a typo in Table 4. The 233 GWh in 2008 for embedded direct and LDC customers should be 333 GWh instead.

School Energy Coalition (SEC) INTERROGATORY #39 List 1

Interrogatory

39. A/10/2, Management's Discussion and Analysis 2007 Quarterly Report:
    a. Please provide details of the $18 million in adjustments made to the PILS amount shown in the 2006 financial statements [found at A/9/1, Attachment 3] and the 2006 utility income.
    b. When was this adjustment made?

Response

a. Hydro One Networks recognized a tax benefit of approximately $14.5 million in respect of the Company's recovery of PIL's relating to 1999-2001 following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized. The balance of approximately $3.5 million pertains to other prior period tax benefits.

b. The $14.5 million capitalized overhead benefit was recognized in the first quarter of 2006 and the $3.5 million benefit was recognized in the third quarter.

School Energy Coalition (SEC) INTERROGATORY #40 List 1

Interrogatory

Ref: C2/6/1, Attachment "A", pg. 1: please explain the two adjustments to regulatory income for Post Employment Benefits expense/payments.

Response

In computing taxable income, the OPEB costs expensed for financial statement purposes are added back and the "actual" cash payments made are deducted.

Please refer to Exhibit C1, Tab 7, Schedule 1, page 3 lines 4 to 28, for an overview of the process to arrive at taxable income.

School Energy Coalition (SEC) INTERROGATORY #41 List 1

Interrogatory

A/2/1- the summary states that the revenue deficiency represents a distribution rate impact of approximately 4%. Please prepare a schedule showing existing and proposed fixed and variable distribution rates for typical residential (1,000kWh per month), small commercial (15,000kWh per month), and large commercial (200kW demand) customers.

Response

The February 20, 2008 update of Exhibit A, Tab 2, Schedule 1, page 4, line 22, states that the net distribution rate increase is less than 2.5%, not 4%.

For Legacy customers, the existing fixed and variable distribution rates for Residential, small commercial and large commercial customers are shown in Exhibit G2, Tab 5, Schedule 2, pages 7 to 12. The proposed 2008 fixed and variable rates are shown in Exhibit G2, Tab 5, Schedule 1, pages 8 to 12.

For Acquired Residential customers, the existing fixed and variable distribution rates are shown in Exhibit G2, Tab 2, Schedule 1, Table 1, pages 1 to 4. For Acquired small commercial customers the existing fixed and variable distribution rates are shown in Exhibit G2, Tab 2, Schedule 1, Table 2, pages 4 to 6. For Acquired large commercial customers the existing fixed and variable distribution rates are shown in Exhibit G2, Tab 2, Schedule 1, Table 3, pages 6 to 9. The proposed 2008 fixed and variable rates are shown in Exhibit G2, Tab 6 to Tab 93, Schedule 1.

School Energy Coalition (SEC) INTERROGATORY #42 List 1

Interrogatory

A2/2/2, pg. 6: gross plant in 2006 was $129.6 million more than Board approved but accumulated depreciation was $125.5 million more than Board approved.
Please explain why the variance in accumulated depreciation is so large relative to the variance in gross plant.

Response

The variances in both gross plant and accumulated depreciation in 2006 were due primarily to lower than forecast asset retirements.

The asset retirements in Hydro One Distribution's 2006 rate filing were based on implementation of the new depreciation methodology effective January 2006. As the new methodology was not implemented until January 2007, the retirement of amortizable assets that reached the end of their amortization period did not occur until 2007.

School Energy Coalition (SEC) INTERROGATORY #43 List 1

Interrogatory

Ref: D1/T2/S1/pg 7 of 20, Rate Base – Asset Condition Summary

a. Out of Hydro One's total 1.65 million poles, how many of them are wood poles?

b. Please provide the number of Distribution station and line assets that were identified as "Poor" or "Very Poor", for the period 2004-2008.

Summary of Priority 1 (P1) ACA Results – "Poor" or "Very Poor".

		2004	2005	2006	2007	2008
Stations	Transformers (total transformers=1337, regulators=140)					
	LAR, total station sites = 1-34 (931 Dx Stations, 75 Regulating Stations, 28 Mobile Stations)					
Lines	Wood Poles (total poles = 1,650,000, to identify # of wood poles					
Other	Pole & Pad Mounted Transformers (total = 475,000)					

Response

a. Over 98% of the pole population is made up of wood poles.

b. Please refer to the following table:

		2004	2005	2006	2007	2008
Stations	Transformers	44	*	36	*	*
	LAR***	452	*	50	*	*
Lines	Wood Poles	66,000	*	69,000	*	*
Other	Pole & Pad Mounted Transformers**	NA	NA	NA	NA	NA

* The system wide number of assets in the "Poor" and "Very Poor" category is not derived on an annual basis, as there is no need to go through this exercise annually to manage the program details. Work program replacements and maintenance are established through detail ACA for the equipment in question and considering other factors such as reliability, customer impacts, and safety.

** Pole & Pad Mounted Transformers are P3 assets defined as having low value and low associated risk. As stated on page 4 of Exhibit D1, Tab 2, Schedule 1, these assets are managed using routine programs at the field level and detailed asset condition assessment data is unavailable.

***2004 results contain all sites that were found to exceed MOE guidelines for agricultural and residential land-use. See the response to interrogatory in Exhibit H, Tab 11, Schedule 22 for details on the change in 2006 for determining condition rating for LAR assessments.

School Energy Coalition (SEC) INTERROGATORY #44 List 1

Interrogatory

Ref: D1/T3/S2/pg7 of 29, Capital Expenditure – Sustaining Capital – Stations – Strategic Spare Transformers

a. Please complete the table below.

	2004	2005	2006	2007	2008
In-service Station Transformers				1337	
In-service Regulators				140	
Major Station Failures					
Spare Transformers					
Spare Regulators					

b. What is the required level of spare transformers and regulators to be maintained? Has this level been changed over the past 4 years?

c. What is the average price escalation for transformers and regulators over the past 4 years?

Response

a. The following represent the year end quantities where available.

	2004	2005	2006	2007	2008
In-service Station Transformers	1353	1345 (estimate)	1337	1335	1336 (estimate)
In-service Regulators	136	138 (estimate)	140	141	141 (estimate)
Major Station Failures	37	32	25	23	*
Spare Transformers	N/A	155 (includes regulators)	130 (estimate for combined)	98	101
Spare Regulators	N/A			14	15

* Hydro One does not place a specific year end target for the number of transformer failures; rather reliability is assessed from a directional perspective for this asset class.

b. The projected level of spare transformers and regulators to be maintained during 2008 is 101 transformers and 15 regulators. This includes the new 2008 purchases, but could vary depending on the number of failures that occur during the year.

c. The average price escalation for transformers and regulators over the past 4 years has been 35-50%.

SEC INTERROGATORY #45 List 1

Interrogatory

Ref: D1/T3/S2/pg7 of 29, Capital Expenditure – Sustaining Capital – Stations – Strategic Spare Transformers

a. Please complete the table below.

	2004	2005	2006	2007	2008
Wood Structure Replacement Spending- Under Line Asset Replacement Program	$19.1M	$18.5M	$30.3M	$38.5M	$39.8M
# Wood Poles Replaced Under Line Asset Replacement Program			5200	6700	7000
Wood Poles Replacement Spending – Under other Programs ($M)					
# Wood Poles Replaced – Under Other Programs (D2/T2/S3/#S7)					9000-13000

b. Please separately identify material and equipment price escalation.

c. Hydro One's annual testing targets are to remain at about 300,000 poles. Please confirm that all Hydro One Distribution System's 1.65 million poles will have been tested within 5-6 years.

Response

a. Please refer to completed table below.

	2004	2005	2006	2007	2008
Wood Structure Replacement Spending - Program	$19.1M	$18.5M	$30.3M	$40.1M	$39.8M
# of Wood Poles Replaced Under Program	3,082	2,699	5,193	6,852	7,000
Wood Poles Replacement Spending – Other Programs*	NA	NA	NA	NA	NA
Wood Poles Replaced Under Other Programs	9,000 – 13,000	9,000 – 13,000	9,000 – 13,000	9,000 – 13,000	9,000 – 13,000

*Breakdowns of expenditures for other programs are not available to the level of detail required for separating out pole replacement expenditures.

b. Material includes poles, insulators, crossarms, conductor, and line hardware and makes up over 90% of the cost with pole replacement. Over the 2004 to 2007 period, material costs have increased by about 30%.

c. Over the last 3 years Hydro One has assessed approximately 300,000 poles annually and will continue to do so until all poles have been assessed, with completion by about 2010. In this case all poles on Hydro One's Distribution System will have been assessed in about a 6 year time frame.

School Energy Coalition (SEC) INTERROGATORY #46 List 1

Interrogatory

Ref a: D1/T3/S2/ pg 27 of 29, Capital Expenditure – Sustaining – Metering – Smart Meters

Ref b: Investment Justification Sheets #S19

a. On page 27 of Ref a, Hydro One's commitment by end of 2008 is to install 370,000 smart meters. In Ref b, Hydro One has identified a target of 240,000 smart meters by end of 2008. Please reconcile.

b. The table below shows the cost per smart meter seems to have increased dramatically from 2007 to 2008. Please explain the 39% increase in the cost per smart meter from 2007 to 2008.

	2007	2008
Budget [D1/3/2, pg.23]	$76.7million	$164.8million
# of Meters to be installed [D1/3/2, pg.24]	240,000	370,000
Cost per meter	$319.58	$445.40

c. The original evidence filed August 21, 2007 shows 2007 expenditures for smart meters at $121.5 million and projected number of meters to be installed as 240,000 for 2007. The updated evidence filed February 20, 2008, however, shows the 2007 budget as $76.7 but the number of meters installed (240,000) has not changed. If the number of meters installed in 2007 was 240,000 as stated in the evidence, please explain why the cost per meter for 2007 has apparently decreased so dramatically as between the original filing and the updated filing.

d. Please explain why the 2008 budget for smart meters, $164.8 million, was not changed in the updated evidence despite the fact that the 2007 figures show a decrease in the cost per meter.

e. On page 13 of the Board's Decision with Reasons EB-2007-0063 dated August 8, 2007, half of Hydro One's up-front Smart Meter related project management costs were allowed. The Decision also states that the remaining amount should be supported with further and better evidence to justify the prudence of this cost at the time if its 2008 rate application. Please explain how Hydro One intends to comply with that directive.

Response

a) Your reference a) refers to 240,000 meters by the end of 2007. Reference b) indicates 240,000 meters by 2008 (meaning by the start of 2008 which is the same as the end of 2007). They are the same number for the same period.

b) Please refer to the IR response in Exhibit H, Tab 1, Schedule 127, part (d)

c) The reduced costs are not as a result of a reduced number of meter installations in 2007, but rather the original evidence assumed we would be completing the majority of the CIS upgrades and Integration to the provincial MDMR in 2007. We also assumed we would be changing meters where meter socket adapters was involved or where meter access (second trip plus scheduling) was involved. In fact, the number of meter installs in 2007 has exceeded the forecast.

d) We expect that the 2008 budget figure will still be reflective of the work to be performed. The work that was originally intended for 2007 and 2008 is essentially being deferred to 2008 and 2009 so 2008 is largely unaffected.

e) Hydro One added support information for its project management costs in the December 18, 2008 update to its evidence and further details in Exhibit H, Tab 1, Schedule 127(k).

School Energy Coalition (SEC) INTERROGATORY #47 List 1

Interrogatory

Ref: D1/T3/S3/ pg 10 of 18, Capital Expenditure – Development – System Capability Reinforcement

2008 spending for System Capability Reinforcement is $44 million, an increase of 22% over the bridge year and 32% above the historic average.

a. Please separately identify the year over year escalation in material and equipment costs, from 2004 to 2008.

Response

For year over year escalation for material and equipment refer to Exhibit H, Tab 1, Schedule 19 section a.

School Energy Coalition (SEC) INTERROGATORY #48 List 1

Interrogatory

Ref: D2/T2/S3/ #O1, Capital Expenditure – Operations

a. Please explain why 2008 spending of $1.3 million on system-data archiving and management be put into rate base when it appears the project won't be in service until September 2009.

Response

The plan was to have the Data Mart partially in-service in 2008 with enhancements continuing to full completion in 2009. The amounts shown were for that portion expected to be in service by end of 2008.

School Energy Coalition (SEC) INTERROGATORY #49 List 1

Interrogatory

A/3/1, pg. 3, 9: the evidence states that Hydro One's distribution system operates in a service territory characterized by low customer densities.

a. What does Hydro One consider to be "low customer densities".
b. What proportion of Hydro One's service territory meets that definition?
c. At pg. 9: please explain the density differences between Hydro One's rural and urban customers.
d. What proportion of Hydro One's customers live in municipalities of 5,000 or more overall density?

Response

a. The statement on page 3 of Exhibit A, Tab 3, Schedule 1 was intended to convey that Hydro One's service territory is largely rural with only pockets of concentrated population. As shown in page 2-9 of the Distribution Benchmarking Study provided in Exhibit A Tab 15 Schedule 2, Hydro One, of the 12 peer utilities compared, Hydro One has the second smallest density on a customers per circuit km bases.

b. It is estimated that the vast majority of Hydro One's 650,000 square km service territory has "low customer densities".

c. Hydro One's urban density criteria calls for a contiguous area of density, with 3,000 or more customers and at least 60 customers per kilometer of line. Hydro One's medium density criteria is defined as areas containing 100 or more customers with a line density of at least 15 customers per kilometre. Customers not meeting either of these criteria are considered low density.

d. It is not clear what is meant by "municipalities of 5,000 or more overall density". Hydro One Distribution can say that approximately 10% of its customers are in urban communities of over 5,000 customers.

School Energy Coalition (SEC) INTERROGATORY #50 List 1

Interrogatory

A/6/1: Please provide copies of any material change notices Hydro One has filed with the Board in respect of section 14.2 of its Distribution Licence.

Response

Hydro One has not filed any notifications under section 14.2 of its licence since the Board issued its previous Distribution Rate Order to Hydro One on April 30, 2007.

School Energy Coalition (SEC) INTERROGATORY #51 List 1

Interrogatory

A/8/2, pg. 9: please provide copies of the Letters of Disclosure and Letters of Representation provided by the Vice-Presidents during 2007.

Response

Information contained in the documents being requested is confidential, commercially sensitive information provided to our auditors, which is not intended for public disclosure and would prejudice Hydro One Inc.'s business interests if it were disclosed. The information contained therein is reviewed by and taken into account by our auditors when auditing and reporting on Hydro One Inc.'s annual consolidated financial statements. The relationship between a client and its auditor is one of trust and candour, wherein the client must be able to have frank, open communications with its auditor regarding known or potential business issues in order to receive accurate, well-informed counsel in return, so as to produce balanced, fair representations, in all material respects, of the financial position of the corporation it audits. In this way, the confidential relationship which exists between the client and its auditor helps to promote a public interest of fair, accurate financial statements, free of material misstatement, upon which the public can rely.

The disclosure of the documents being requested would interfere with this relationship, and indeed with the process of auditing established by audit firms in following Canadian generally accepted auditing standards. Information in these communications regularly includes confidential transactional and operational details provided by the Company to its external auditor to make them aware of potential reporting and accounting issues such as: assessments of the potential outcomes of legal proceedings; labour relations developments; status of in progress government audits; corporate strategies; pending contracts and agreements; possible future events that could be accounted for as 'subsequent events;' factors relating to recording and measuring contingent gains and losses. Disclosure of this information could result in financial loss to the Company and unfair gains accruing to others.

Furthermore, the documents being requested bear no relevance on Hydro One Networks Inc.'s application for an increase in distribution rates, and thus should not be disclosable. Additionally, if it were requested formally pursuant to the Freedom of Information and Protection of Privacy Act ("FIPPA"), access to this information would have been denied pursuant to applicable exemptions under FIPPA.

School Energy Coalition (SEC) INTERROGATORY #1 List 2

Interrogatory

Ref: G1/1/1, Introduction to Cost Allocation and Rate Design

a. Pg. 1. Please provide a specific reference for the "OEB-approved rate design methodology" employed by the Company in designing the new rate classes.

b. Pg. 3: Please advise the amount of cost savings expected by the Company in each of years 2008, 2009 and 2010 as a result of the reduction in numbers of rate classes, and provide all internal documents, including studies, memos, emails, presentations and otherwise, estimating or calculating those savings.

Response

a. The OEB Distribution Rate Handbook issued in the year 2000, in section 4.1.1, Distribution Customer Classes, first paragraph, refers to the following customer classes: residential, sentinel lights, general service, street lighting and large use. These are the customer classes that Hydro One used in proposing the 12 new customer classes. The rate design for the new classes is consistent with the OEB Guidelines in the same document, Section 4.4.1, of including a monthly service charge and a volumetric charge.

b. Hydro One does not anticipate realizing any cost savings until rate harmonization is complete in 2011. Once our proposal to reduce the number of rate classes and harmonize existing acquired community rates with retail legacy rates is implemented it anticipated that cost savings will result from the following benefits:

- Better alignment to OEB distribution rate handbook and direction on standard rate classes; more consistency with OEB guidelines;
- Less time and effort on rate filings, including reduced volume of materials to be prepared and printed;
- Reduced initial CIS system development and installation costs;
- More streamlined customer communications; increased opportunity for customized inserts with customer bills;
- Easier reference to rate classes on Hydro One web site;
- Reduced risk of human error when setting up new accounts, choosing appropriate rate classes, reviewing System change documents;
- Reduced complaints where neighboring customers pay different rates; and
- Increased potential for comparison and benchmarking across distributors.

School Energy Coalition (SEC) INTERROGATORY #2 List 2

Interrogatory

Ref: G1/2/1, Customer Classification

a. Pg. 2. Please provide any internal studies or other records evidencing customer confusion to date arising out of the large number of customer classes.

b. Pg. 2. Please confirm that the 12 new customer classes proposed by the Company were neither proposed by nor approved by the stakeholders at the Company's stakeholdering sessions.

Response

a. There are no internal studies undertaken or tracking of incidences of customer confusion due to large number of customer classes.

b. Exhibit A, Tab 16, Schedule 1, page 10, line 8, to page 15 line 8, summarizes the discussions and conclusions drawn from the second and third stakeholder session. Hydro One proposed 10 customer classes at the second session, which SEC did not participate in. Based on feedback received from stakeholders at this session, Hydro One presented an additional 2 classes at the third session. Hydro One believes there was general agreement from stakeholders for our 12 class proposal at the third session and there were no alternate agreed-to proposals presented by stakeholders. The approval of any changes to customer classes rests with the OEB.

School Energy Coalition (SEC) INTERROGATORY #3 List 2

Interrogatory

Ref: G1/2/2, Current Customer Classification

a. Pg. 4. Please confirm that the term "customers" in this page refers to billing accounts, rather than actual entities (ie. if an entity has more than one connection point, they will be counted as more than one customer for this purpose). If the Company has the information, please provide the Company's total number of actual customers, and total number of actual customers in the Acquired LDC service territories.

b. Pg. 5. Please advise whether the existing "Low Use Secondary Services" subclass includes any schools, and if so how many.

Response

a. Yes, "customers" are billing accounts except for the ST class which have many bill accounts per customer. Assuming the term actual customer relates to individual entries with multiple service points, this information is not readily available.

b. Only one school account is set up with a Low Use Secondary account, a portable.

School Energy Coalition (SEC) INTERROGATORY #4 List 2

Interrogatory

Ref: G1/2/3, Proposed Customer Classification

a. Pg. 2. Please provide the rationale behind continuing with the existing density test of 3000 or more customers with a line density of at least 60 customers per kilometer. If the Company has any studies, reports, or other evidence showing that this threshold is (or is not) an appropriate delineator relative to cost causality, please provide those materials.

b. Pg. 2. Please provide a sensitivity analysis showing numbers of customers (Tables 1 through 8 restated) and proposed rates for each class assuming varying density thresholds. Use other possible density thresholds that the Company considers reasonable to consider, or, if the Company has no other candidate tests, use 2,000 customers with a line density of at least 40 customers per kilometer, and 5,000 customers with a line density of at least 75 customers per kilometer.

c. Pg. 2. Please advise how the 3000 customers test is applied, ie. on what basis is the geographic area selected in which the test is to be applied. Please advise the rationale behind using that particular basis for geographic division. Please advise alternative methods of assessing customer density areas, and the reasons why those methods were rejected.

d. Pg. 4. (Also G2/1/1, pg. 4) Please confirm that the four General Service categories of UGSe, UGSd, GSe, and GSd, do not use the same 50 KW test that is employed by other LDCs. Please advise the method by which the Company proposes to determine whether a customer should be demand or energy billed, and if there is a demand limit (e.g. 50 KW), any exceptions to that demand limit. Please describe how Hydro One's proposed test would differ from that employed by other LDCs.

Response

a. Please see the response at Exhibit H, Tab 10, Schedule 34.

b. The requested density scenarios cannot be done in a reasonable time-frame since it would require all customers to be reclassified based on new density metrics to define new rate classes. New load shapes will need to be developed for these new rate classes and new Cost Allocation Model allocators would need to be developed. All these data would then be used in a new Cost Allocation Model run.

c. Hydro One used the same method as for previous density studies done at the time of the introduction of the Urban rate class. Other alternative methods were not considered in order to provide consistency with the current urban density areas.

The method consists of identifying each location in the Province with a cluster of customers (i.e. towns, large suburban areas and other areas of relatively high density). Each location is then analyzed to determine if there are more than 3000 customers in the customer cluster.

If there are not more than 3000 customers, the location is not deemed eligible for urban rate class.

If the cluster does have more than 3000 customers, the length of feeders serving the cluster is obtained, and the # of customers per km is determined. The geographic cluster of customers is extended to lower density areas until the customer density falls below the urban density criteria of 60 customers per km. This urban boundary limit is adjusted for logical municipal and geographic boundaries for efficient application of the rate class.

d. Hydro One monitors consumption on a calendar year basis to determine if an account should be demand or energy billed.

For demand metered customers, measured demand is monitored on a calendar year basis to determine whether they should be billed demand or energy only. Those accounts with an average monthly peak demand greater than 50 kilowatts over the 12 month calendar year will be demand billed. Those accounts with an average monthly peak demand of 50 kilowatts or less over a 12 month period will be energy billed (kWh).

Energy-only metered non-residential accounts are monitored on a calendar year basis, to identify services that have exceeded 150,000 kilowatt-hours annually and require a demand meter to be installed.

The annual review occurs in the first quarter of the year, based on the previous calendar year billing period. Any accounts that require reclassification for billing purposes to demand or energy billed will occur effective the next scheduled bill after the annual review.

Hydro One is unaware of the method by which other LDC's determine if a customer should be demand or energy billed.

School Energy Coalition (SEC) INTERROGATORY #5 List 2

Interrogatory

Ref: G1/2/5, Harmonization of Acquired LDC Customers and Consolidation of Legacy Customer Classes:

a. Pg. 1. Please provide the Company's rationale for excluding Hydro One Brampton from the harmonization plan. Please file any agreements or other documents that prohibit Hydro One from harmonizing Hydro One Brampton's rates with those of the Legacy customers.

b. Pg. 2. Please provide all studies, reports, analyses, memos, emails, and other documents in the Company's possession dealing with the actual costs of distributing electricity in all or any of the Acquired franchise areas. Please confirm that the Company has not done a formal cost allocation study or studies to determine the costs of serving any of the Acquired franchise areas, or comparing the costs of serving the Acquired customers vs. the Legacy customers.

c. Pg. 5. Please advise why the current fixed service charges are being "truncated downward". Please advise the impact that would arise if the actual existing service charges were used in the proposed formula.

d. Pg. 5. Please provide a brief description of the primary cost differentials driving the class revenue requirements for i) UGSe and GSe, and ii) UGSd and GSd, ie. what are the primary differences in cost allocation that cause the rates to be different. Please provide any studies in the Company's possession showing the different cost of serving these proposed classes.

e. Pg. 5. Please confirm that, under the Company's proposal, only the increase in the fixed charge will be phased in; the volumetric charges will, in fact, decrease as the phasing occurs. Please describe the rationale behind this approach, and the impacts on customers having different existing rate levels and mixes of fixed and variable charges.

f. Pg. 8. Please provide Table 3, revised to show the impacts on the distribution component of the bill only (ie. H1 fixed charge and variable charge).

Response

a. Hydro One Brampton Networks Inc. is a separate subsidiary of Hydro One Inc. as shown in Figure 1 of Exhibit A, Tab 8, Schedule 1. As such Hydro One Brampton Networks Inc. is regulated by the Board as a stand alone entity. The Board released their Decision respecting Hydro One Brampton's 2008 Distribution Rate Application (EB-2007-0882) on March 19, 2008.

b. No such studies exist. Hydro One has not done studies to determine the costs of serving any of the Acquired franchise areas. The assets and operations of the Acquired LDCs were fully integrated within Hydro One Distribution at the time of sale closure.

c. The rationale of truncating the existing service charge and then adding the incremental increase was to quickly reduce the number of basic distribution rates. If the actual existing service charge was used onto which increments were added, there would have been 88 Service Charges as compared to reduce level of 43 in Year 1 for the Acquireds in the proposed R1 rate class.

d. The 2 main factors are the density weights and the use of distribution assets. The urban density class has greater customer per km density and will be assigned less costs. Further, the Cost Allocation Model has assumed that the demand-billed customers are connected down to Primary while the energy-billed customers are connected down to Secondary. Thus, the demand-billed customers are allocated less costs. Therefore, urban customers and demand-billed customers are allocated less costs and thus have lower rates than the rural and energy-billed customers.
No Company studies exist which demonstrate this cost differential for the proposed classes.

e. The proposed Phase-In Plan is to Phase-In the Service Charge in equal steps over the 4 years and to use a common variable charge to achieve the class revenue requirement. Yes, as the Service Charge is increased, the necessary Common Variable Charge is projected to decline. The Service Charge Phase-In was chosen as a mitigation impact to smaller volume users where the Service Charge is a more substantial part of their total bill.
The lower Service Charge and higher Common Variable Charge will benefit lower volume users in the near-term at the expense of the higher volume users who are more impacted by the higher Common Variable Charge.

f. Table 3 of Exhibit G1 Tab 2 Schedule 5 is re-presented below with the average bill impacts on the distribution bill including the Rate Riders at the Target Rates.

Rate Class	2006 Customers	Range of Impacts on Distribution Bill [%]
Residential	141,305	3 to 167
General Service	20,697	-11 to 244

School Energy Coalition (SEC) INTERROGATORY #6 List 2

Interrogatory

Ref: G1/2/6, Low Use Secondary Customer Rates

a. Pg. 1. Please confirm that the Company's proposal means that customers with multiple delivery points will pay multiple fixed monthly charges.

b. Pg. 1. Please advise the Company's policy if a customer with multiple delivery points wishes to consolidate its deliveries through a smaller numbers of delivery points, e.g. who would pay the costs of changing the metering, protection devices, wires, etc., and on what basis, and what other costs or restrictions would apply to that customer?

Response

a. Yes, if the multiple delivery point is for an additional service above the main electric account. Hydro One's proposal is that customers with a low use secondary account will be charged a fixed monthly service charge. If the customer has another account, such as a home, which is also separately connected and metered, they will pay the fixed monthly service charge for each of their accounts.

b. Under Hydro One policy, establishing a central metered service may be an option, but each connection situation is different and this option may not apply in each case. Following our Conditions of Service guidelines, the customer would be responsible for the incremental costs of changing to central metered service.

School Energy Coalition (SEC) INTERROGATORY #7 List 2

Interrogatory

Ref: G1/3/1, Cost Allocation of Revenue Requirement

a. Pg. 2. Please provide a table showing what the proposed rates would be for each of the new classes in 2008 (and the target harmonized rates) if all rates were at revenue to cost ratios of 1.0.

b. Pg. 4. Please confirm that the Company proposes to collect from the four GS classes a total of $12.1 million more than the costs to serve those classes in 2008.

c. Pg. 5. Please explain the Company's rationale for rejecting revenue to cost ratios of 1.0 as set forth in this table, when all of the total bill impacts are within the 10% maximum applied by the Company to the harmonization of the Acquireds.

Response

a. The table below lists the target rates based on a Revenue-to-Cost Ratio of 1 for all proposed Rate Classes. The 2008 target rates based on revenue to cost ratios of 1.0, would require analysis of bill impacts based on average consumption and the development of a mitigation plan to keep impacts at or below the impact thresholds for the 2008 to 2010 period. Development of 2008 rates under this scenario could not be done in the time frame allowed to file responses to interrogatories.

Rate Class	SrChg	c/kWh	$/kW
UR	14.32	2.29	-
R1	19.04	3.26	-
R2	49.91	2.84	-
Seasonal	19.51	6.38	-
GSe	30.97	3.02	-
GSd	46.75		9.00
UGe	12.33	1.65	
UGd	29.19		7.25
St Lgt	1.00	6.59	-
Sen Lgt	1.00	15.94	-
Dgen	36.66		7.07
ST	372.12		0.55

ST class	**Rates:**
$ 188	ST Service Charge ($/month)
$ 553	Meter Charge (for HON-ownership) ($/month)
$ 1.42	HVDS-high ($/kW/month)
$ 2.48	HVDS-low ($/kW/month)
$ 1.06	LVDS-low ($/kW/month)
$ 0.48	Common Line ($/kW/month)
$ 607	Specific ST Line ($/km/month)
$ 470	Specific Primary Line ($/km/month)

b. The rates Revenue Requirement for the 4 General Service classes is being set at $12.8M higher than the results of the Cost Allocation Model.

c. The average impacts in Table 3 of Exhibit G1, Tab 3, Schedule 1, page 5 is presented for each rate class as a customer weighted average of the component rate classes. For example, the R1 class at a Revenue-to-Cost ratio of 1 is projected to have a customer weighted total bill impact of 8.3%. This is dominated by 80% of existing R1 customers who are projected to have an average total bill impact of 5%. The other 20% or the 72,682 Acquired customers will have average total bill impacts of 20%.

To mitigate impacts, a Revenue-to-Cost Ratio of 1 has not been adopted and a Revenue Requirement shortfall of $2.46M is being deferred for later recovery.

School Energy Coalition (SEC) INTERROGATORY #8 List 2

Interrogatory

Ref: G1/5/1, Regulatory Asset Recovery Allocation to Customer Groups

a. Pg. 3. Please advise how the smart meter costs are charged within customer groups, ie. in a fixed charge, or in a volumetric charge. If they are charged in a volumetric charge (rider), please reconcile this proposal with the cost causality judgment that these costs are driven by number of customers, not volumes.

Response

The smart meter costs are allocated to customer classes based on number of customers. The OEB directed that all distributors should recover regulatory rate riders through the volumetric charge only, in its decision on Proceeding RP-2004-0064/RP-2004-0069/RP-2004-0100/RP-2004-0117/0118 issued December 9, 2004, page 84, section 9.0.4.

School Energy Coalition (SEC) INTERROGATORY #9 List 2

Interrogatory

Ref: G1/5/3, Development of Regulatory Asset Rider #3

a. Pg. 2. Please advise the extent, if any, that when the Regulatory Asset Riders are applied to the Acquireds, costs will be recovered from those customers that were not incurred for their benefit, ie. that Acquireds would be overpaying for those costs.

Response

When the Regulatory Rider # 3 is applied to Acquired customers, costs recovered from these customers were incurred for their benefit. All the costs in Rider # 3 reflect costs incurred when Acquired customers were served by Hydro One. Therefore, Acquired will not be overpaying for the costs in Rider # 3.

School Energy Coalition (SEC) INTERROGATORY #10 List 2

Interrogatory

Ref: G1/7/1, Bill Impacts Legacy Customers

a. Pg. 3. Please restate Table 3 on the basis of revenue to cost ratios of 1.0 in all classes.

b. Pg. 6. Please provide the calculations behind this Table 4 on a sample bill basis, using the format set forth in the Board's 2006 EDR model for Bill Impacts. Please provide your answer in Excel format, with all formulae live. If the results of the 2006 EDR Model sample bills do not correspond with this Table, please provide a brief explanation of how this table was calculated differently than the Board's Model, and reconcile the two approaches numerically.

c. Pg. 6. Please restate Table 4 on the basis of revenue to cost ratios of 1.0 in all classes.

Response

a. Table 3 includes the proposed RTSR rates. Theses rates are unaffected by different revenue to cost ratios.

b. The only difference in the 2006 EDR Model and the Impacts Sheets provided in Exhibit G2, Tab 5, Schedules 3 to 6 is the inclusion of GST in the 2006 EDR Model and not in the Hydro One Distribution model.

The impact levels are the same for the Residential, GS<50 kW and GS>50 kW rate classes.

The difference is in layout, the 2006 EDR model has its charges listed vertically while Hydro One Distribution has laid the charges out horizontally per impact scenario level. Hydro One Distribution's horizontal charges layout is necessary to accommodate the numerous rate classes, especially for all its Acquired distributors which are presented vertically.

The same layout has been used by Hydro One is previous OEB proceedings.

The information requested has been calculated and is provided in Attachment A. An excel spreadsheet of the results was provided to SEC under separate cover.

c. Table 4 of Exhibit G1, Tab 7, Schedule 1, has been re-run with the requested scenario of all proposed rate classes having a Revenue-to-Cost ratio of 1.0.

New Class	Existing Class	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
UR	UR	14.2%	6.8%	1.3%	1.0%
	R1	-13.0%	-16.7%	-6.5%	-6.9%
	R2	-23.4%	-26.6%	-10.8%	-11.1%
	F1 wRRA	-26.9%	-29.0%	-11.9%	-11.8%
R1	R1	20.5%	15.3%	5.1%	4.9%
R2	R2	2.5%	-1.0%	-0.4%	-0.8%
	F1 wRRA	-2.3%	-3.4%	-1.3%	-1.3%
	F3 wRRA	-15.7%	-15.6%	-5.4%	-4.7%
Seasonal	R3	47.8%	40.8%	20.9%	21.3%
	R4	2.3%	-0.8%	-0.5%	-0.1%
UGe	F1 nRRA	-57.1%	-59.1%	-23.2%	-24.7%
	G1	-54.0%	-56.2%	-21.2%	-22.4%
	G3	-58.2%	-59.2%	-22.4%	-23.4%
	UG	-35.4%	-37.3%	-11.1%	-12.6%
UGd	G1	-24.2%	-29.8%	-10.0%	-10.2%
	G3	-27.2%	-30.3%	-8.9%	-9.1%
	UG	-12.6%	-16.6%	-5.7%	-5.9%
GSe	F1 nRRA	-13.4%	-15.5%	-6.1%	-7.8%
	F3 nRRA	-18.2%	-19.5%	-6.7%	-7.7%
	G1	-7.2%	-9.8%	-3.7%	-5.2%
	G3	-15.5%	-16.7%	-5.4%	-6.5%
	T	-70.5%	-70.8%	-45.6%	-46.2%
	Unmtr	45.9%	39.6%	11.5%	9.85%
GSd	F1 nRRA	24.4%	16.8%	2.4%	-0.2%
	F3 nRRA	-17.1%	-19.5%	-6.0%	-9.0%
	F1 wRRA	28.5%	20.3%	3.2%	0.5%
	F3 wRRA	-15.8%	-18.2%	-5.6%	-8.5%
	G1	-5.2%	-9.5%	-4.2%	-6.1%
	G3	-8.9%	-11.5%	-3.4%	-5.3%
	T	-7.7%	-10.1%	-2.9%	-5.0%
DGen	G3d	-28.3%	-28.9%	-7.1%	-12.7%

New Class	Existing Class	Basic Distribution Bill Only	Distribution Bill incl Riders	Total Bill incl Distribution and Riders	Total Bill incl Distribution and Riders plus RTSR
	Td	-23.4%	-23.9%	-14.8%	-30.9%
	G3e	32.2%	32.3%	17.4%	15.1%
	Te	-22.0%	-21.6%	-17.6%	-15.9%
	GS Eganville	110.0%	111.7%	109.3%	111.9%
Street Lgts	Street Lgts	68.0%	64.6%	21.6%	21.7%
	Terrace Bay	152.4%	99.0%	36.2%	40.3%
Sentinel Lgts	Sentinel Lgts	343.4%	335.1%	118.0%	118.1%

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																						5	5.9	600
		May-07						Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF			Commodity		
	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		0.920		1.078	old Other	new Other			$Chg old	$ Chg new
	1,000																					Band 1	Band 2		
UR	1,000	14.32	1.83	0.2	0.05	2.08	35.12	14.32	2.29	0.050	(0.02)	2.32	37.52	0.70	0.62	0.94	0.92	1.0920	1.078	24.04	23.60	600	400	59.0	58.2
R1	1,000	19.04	2.38	0.15	0.07	2.60	45.04	14.32	2.29	0.050	(0.02)	2.32	37.52	0.70	0.62	0.94	0.92	1.0920	1.078	24.04	23.60	600	400	59.0	58.2
R2	1,000	29.22	1.94	0.12	0.13	2.19	51.12	14.32	2.29	0.050	(0.02)	2.32	37.52	0.70	0.62	0.94	0.92	1.0920	1.078	24.04	23.60	600	400	59.0	58.2
F1 wRRA	1,000	28.61	2.24	0.08	0.1	2.42	52.81	14.32	2.29	0.050	(0.02)	2.32	37.52	0.70	0.62	0.89	0.92	1.0920	1.078	23.49	23.60	600	400	59.0	58.2

	Total Old Bill	Total New Bill		Dx Basic old	Dx Basic New	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
UR	118.18	119.32	UR	32.62	37.26	14.2%	35.12	37.52	6.8%	118.18	119.75	1.3%	118.18	119.32	1.0%
R1	128.10	119.32	R1	42.84	37.26	-13.0%	45.04	37.52	-16.7%	128.10	119.75	-6.5%	128.10	119.32	-6.9%
R2	134.18	119.32	R2	48.62	37.26	-23.4%	51.12	37.52	-26.6%	134.18	119.75	-10.8%	134.18	119.32	-11.1%
F1 wRRA	135.33	119.32	F1 wRRA	51.01	37.26	-26.9%	52.81	37.52	-29.0%	135.33	119.21	-11.9%	135.33	119.32	-11.8%

																											5	5.9	600		
		May-07							Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF				Commodity				
	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		0.930		1.085	old Other	new Other	Band 1	Band 2	$Chg old	$ Chg new					
	1,000																													
R1	1,000	19.04	2.38	0.15	0.07	2.60	45.04	19.04	2.60	0.07	(0.04)	2.64	45.40	0.70	0.62	0.94	0.93	1.0920	1.085	24.04	23.82	600	400	59.0	58.6					

	Total Old Bill	Total New Bill		Dx Basic old	Dx Basic New	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
R1	128.10	127.83	R1	42.84	45.07	5.2%	45.04	45.40	0.8%	128.10	128.05	0.0%	128.10	127.83	-0.2%

5	5.9	600

		May-07						Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF			Commodity				
	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg net of RRA	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		0.890		1.092	old Other	new Other	Band	Band 2	$Chg old	$ Chg new	Total Old Bill
	1,000																									
R2	1,000	29.22	1.94	0.12	0.13	2.19	51.12	21.41	3.10	0.130	(0.05)	3.18	53.17	0.70	0.62	0.94	0.89	1.0920	1.092	24.04	23.49	600	400	59.0	59.0	134.18
F1	1,000	28.61	2.24	0.08	0.1	2.42	52.81	21.41	3.10	0.100	(0.05)	3.15	52.87	0.70	0.62	0.89	0.89	1.0920	1.092	23.49	23.49	600	400	59.0	59.0	135.33
F3	1,000	30.16	2.89	0.03	0.04	2.96	59.76	21.41	3.10	0.040	(0.05)	3.09	52.27	0.70	0.62	0.84	0.89	1.0610	1.092	22.49	23.49	600	400	57.2	59.0	139.45

	Total New Bill		Dx Basic o	Dx Basic N	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
R2	135.69	R2	48.62	52.36	7.7%	51.12	53.17	4.0%	134.18	136.23	1.5%	134.18	135.69	1.1%
F1	135.39	F1 wRRA	51.01	52.36	2.6%	52.81	52.87	0.1%	135.33	135.39	0.0%	135.33	135.39	0.0%
F3	134.79	F3 wRRA	59.06	52.36	-11.3%	59.76	52.27	-12.5%	139.45	133.79	-4.1%	139.45	134.79	-3.3%

Seasonal

																								5	5.9	600		
		May-07						Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF			Commodity					
	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg net of RRA	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		0.870		1.092	old Other	new Other	Band 1	Band 2	$Chg old	$ Chg new	Total Old Bill		
R3	400	19.51	2.74	0.35	0.15	3.24	32.47	19.51	6.38	0.150	0.02	6.55	45.71	0.70	0.62	0.81	0.870	1.0920	1.092	9.05	9.31	400	-	21.8	21.8	63.36		
R4	400	36.36	1.92	0.36	0.24	2.52	46.44	19.51	6.38	0.240	0.02	6.64	46.07	0.70	0.62	0.81	0.870	1.0920	1.092	9.05	9.31	400	-	21.8	21.8	77.33		

Seasonal

	Total New Bill		Dx Basic old	Dx Basic New	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
R3	76.86	R3	30.47	45.05	47.8%	32.47	45.71	40.8%	63.36	76.60	20.9%	63.36	76.86	21.3%
R4	77.22	R4	44.04	45.05	2.3%	46.44	46.07	-0.8%	77.33	76.96	-0.5%	77.33	77.22	-0.1%

																								5	**5.9**	**750**
		May-07						Target Rates						**DRC**	**WMSC**	**Old RTSR**	**New RTSR**	**Old TLF**	**New TLF**			Commodity			
	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		0.690		1.092	old Other	new Other	Band 1	Band 2	$Chg old	$ Chg new
	2,000																								
F1	2,000	60.71	2.24	0.08	0.1	2.42	109.11	12.33	2.09	0.03	-0.06	2.06	53.49	0.70	0.62	0.89	0.69	1.0920	1.092	46.98	42.61	750	1,250	122.1	122.1
G1	2,000	36.02	3.12	0.09	0.09	3.30	102.02	12.33	2.09	0.03	-0.06	2.06	53.49	0.70	0.62	0.86	0.69	1.0920	1.092	46.32	42.61	750	1,250	122.1	122.1
G3	2,000	46.75	3.07	0.02	0.05	3.14	109.55	12.33	2.09	0.03	-0.06	2.06	53.49	0.70	0.62	0.85	0.69	1.0610	1.092	45.19	42.61	750	1,250	118.4	122.1
UG	2,000	15.24	2.74	0.03	0.03	2.80	71.24	12.33	2.09	0.03	-0.06	2.06	53.49	0.70	0.62	0.85	0.69	1.0920	1.092	46.10	42.61	750	1,250	122.1	122.1

	Total Old Bill	Total New Bill		Dx Basic old	Dx Basic New	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
F1	278.19	218.20	F1 nRRA	105.51	54.06	-48.8%	109.11	53.49	-51.0%	278.19	222.57	-20.0%	278.19	218.20	-21.6%
G1	270.45	218.20	G1	98.42	54.06	-45.1%	102.02	53.49	-47.6%	270.45	221.92	-17.9%	270.45	218.20	-19.3%
G3	273.19	218.20	G3	108.15	54.06	-50.0%	109.55	53.49	-51.2%	273.19	220.79	-19.2%	273.19	218.20	-20.1%
UG	239.45	218.20	UG	70.04	54.06	-22.8%	71.24	53.49	-24.9%	239.45	221.70	-7.4%	239.45	218.20	-8.9%

				May 07 Rates						Target Rates																Commodity		
	kWh	kW	LF	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF	old Other	new Other	Band 1	Band 2	$Chg old
	43,164												-0.27			0.7	0.62		2.680		1.061						
G1	43,164	133	0.45	36.02	9.59	0.26	0.29	10.14	1,387	29.19	7.25	0.11	-0.27	7.09	974	0.70	0.62	2.62	2.68	1.0920	1.061	975	965	-	43,164	2,451.0
G3	43,164	133	0.45	46.75	9.91	0.08	0.15	10.14	1,398	29.19	7.25	0.11	-0.27	7.09	974	0.70	0.62	2.75	2.68	1.0610	1.061	975	965	-	43,164	2,381.4
UG	43,164	133	0.45	15.24	8.44	0.10	0.11	8.65	1,168	29.19	7.25	0.11	-0.27	7.09	974	0.70	0.62	2.58	2.68	1.0920	1.061	970	965	-	43,164	2,451.0

0	5.2	0

	$ Chg new	Total Old Bill	Total New Bill		Dx Basic c	Dx Basic I	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
G1	2,381.4	4,813.28	4,320.16	G1	1,313.61	995.53	-24.2%	1,386.88	973.83	-29.8%	4,813.28	4,330.65	-10.0%	4,813.28	4,320.16	-10.2%
G3	2,381.4	4,754.11	4,320.16	G3	1,366.97	995.53	-27.2%	1,397.61	973.83	-30.3%	4,754.11	4,330.33	-8.9%	4,754.11	4,320.16	-9.1%
UG	2,381.4	4,588.61	4,320.16	UG	1,139.63	995.53	-12.6%	1,167.60	973.83	-16.6%	4,588.61	4,325.26	-5.7%	4,588.61	4,320.16	-5.9%

																									5	5.9	750
		May-07						Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF				Commodity			
	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		0.670		1.092	old Other	new Other		Band 1	Band 2	$Chg old	$ Chg new
	2,000																									
F1	2,000	60.71	2.24	0.08	0.1	2.42	109.11	30.97	3.39	0.10	-0.06	3.43	99.56	0.70	0.62	0.89	0.67	1.0920	1.092	46.98	42.17		750	1,250	122.1	122.1
F3	2,000	53.91	2.89	0.03	0.04	2.96	113.11	30.97	3.39	0.04	-0.06	3.37	98.36	0.70	0.62	0.84	0.67	1.0610	1.092	44.98	42.17		750	1,250	118.4	122.1
G1	2,000	36.02	3.12	0.09	0.09	3.30	102.02	30.97	3.39	0.09	-0.06	3.42	99.36	0.70	0.62	0.86	0.67	1.0920	1.092	46.32	42.17		750	1,250	122.1	122.1
G3	2,000	46.75	3.07	0.02	0.05	3.14	109.55	30.97	3.39	0.05	-0.06	3.38	98.56	0.70	0.62	0.85	0.67	1.0610	1.092	45.19	42.17		750	1,250	118.4	122.1
T	2,000	261.54	2.43	0.01	0.03	2.47	310.94	30.97	3.39	0.03	-0.06	3.36	98.16	0.70	0.62	0.84	0.67	1.0610	1.092	44.98	42.17		750	1,250	118.4	122.1

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	Total Old Bill	Total New Bill		Dx Basic (	Dx Basic I	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
F1	278.19	263.84	F1 nRRA	105.51	98.70	-6.5%	109.11	99.56	-8.7%	278.19	268.65	-3.4%	278.19	263.84	-5.2%
F3	276.54	262.64	F3 nRRA	111.71	98.70	-11.6%	113.11	98.36	-13.0%	276.54	265.45	-4.0%	276.54	262.64	-5.0%
G1	270.45	263.64	G1	98.42	98.70	0.3%	102.02	99.36	-2.6%	270.45	267.79	-1.0%	270.45	263.64	-2.5%
G3	273.19	262.84	G3	108.15	98.70	-8.7%	109.55	98.56	-10.0%	273.19	265.86	-2.7%	273.19	262.84	-3.8%
T	474.37	262.44	T	310.14	98.70	-68.2%	310.94	98.16	-68.4%	474.37	265.25	-44.1%	474.37	262.44	-44.7%

Unmtr

																										5	5.9	750			
			May-07							Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF			Commodity					
	Number of customers	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62	0.930	0.670	1.0545	1.092	old Other	new Other	Band 1	Band 2	$Chg old	$ Chg new	Total Old Bill	Total New Bill
		500																										
G1	3,622	500	22.16	3.12	0.09	0.09	3.30	38.66	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.86	0.67	1.0920	1.092	11.58	10.54	500	-	27.3	27.3	77.54	79.05
G3	14	500	6.29	3.07	0.02	0.05	3.14	21.99	24.11	3.39	0.05	-0.06	3.38	41.01	0.70	0.62	0.85	0.67	1.0610	1.092	11.30	10.54	500	-	26.5	27.3	59.81	78.85
UG	392	500	0.79	2.74	0.03	0.03	2.80	14.79	24.11	3.39	0.03	-0.06	3.36	40.91	0.70	0.62	0.85	0.67	1.0920	1.092	11.53	10.54	500	-	27.3	27.3	53.62	78.75
Ailsa Craig	2	500	8.20	1.32	0.17	0.09	1.58	16.10	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	54.13	79.05
Arkona	2	500	1.14	0.86	0.51	0.36	1.73	9.79	24.11	3.39	0.36	-0.06	3.69	42.56	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	47.82	80.40
Arnprior	23	500	10.23	1.17	0.16	0.06	1.39	17.18	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	55.21	78.90
Arran-Elderslie	8	500	3.95	1.03	0.17	0.09	1.29	10.40	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	48.43	79.05
Artemesia	8	500	9.34	1.74	0.49	0.34	2.57	22.19	24.11	3.39	0.34	-0.06	3.67	42.46	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	60.22	80.30
Bancroft	5	500	11.73	1.18	0.17	0.08	1.43	18.88	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	56.91	79.00
Bath	2	500	4.86	1.47	0.29	0.24	2.00	14.86	24.11	3.39	0.24	-0.06	3.57	41.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	52.89	79.80
Blandford-Blenhei	11	500	11.46	1.14	0.28	0.20	1.62	19.56	24.11	3.39	0.20	-0.06	3.53	41.76	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.59	79.60
Blyth	-	500	10.35	1.05	0.26	0.20	1.51	17.90	24.11	3.39	0.20	-0.06	3.53	41.76	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	55.93	79.60
Bobcaygeon	18	500	11.14	1.38	0.18	0.09	1.65	19.39	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.42	79.05
Brighton	3	500	10.99	1.35	0.20	0.08	1.63	19.14	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.17	79.00
Brockville	39	500	10.37	0.78	0.13	0.04	0.95	15.12	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	53.15	78.80
Caledon OH 01																												
Caledon CH 02																												
Caledon OH 06																												
Caledon OH 07																												
Caledon CH																												
Caledon GS 05	85	500	11.20	2.19	0.22	0.20	2.61	24.25	24.11	3.39	0.20	-0.06	3.53	41.76	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	62.28	79.60
Caledon OH																												
Caledon Large User																												
Campbellford-Sey	12	500	7.63	1.19	0.17	0.05	1.41	14.68	24.11	3.39	0.05	-0.06	3.38	41.01	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	52.71	78.85
Carleton Place	31	500	11.36	1.68	0.13	0.07	1.88	20.76	24.11	3.39	0.07	-0.06	3.40	41.11	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	58.79	78.95
Cavan-Millbrook-N	3	500	10.68	1.50	0.33	0.26	2.09	21.13	24.11	3.39	0.26	-0.06	3.59	42.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.16	79.90
Centre Hastings	2	500	8.73	0.97	0.14	0.06	1.17	14.58	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	52.61	78.90
Chalk River	2	500	10.20	1.79	0.39	0.34	2.52	22.80	24.11	3.39	0.34	-0.06	3.67	42.46	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	60.83	80.30
Champlain	10	500	9.83	0.91	0.26	0.15	1.32	16.43	24.11	3.39	0.15	-0.06	3.48	41.51	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	54.46	79.35
Cobden	8	500	10.50	2.13	0.36	0.30	2.79	24.45	24.11	3.39	0.30	-0.06	3.63	42.26	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	62.48	80.10
Deep River	2	500	11.50	2.26	0.15	0.14	2.55	24.25	24.11	3.39	0.14	-0.06	3.47	41.46	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	62.28	79.30
Deseronto	3	500	4.61	1.35	0.13	0.05	1.53	12.26	24.11	3.39	0.05	-0.06	3.38	41.01	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	50.29	78.85
Dryden	4	500	9.09	1.03	0.12	0.04	1.19	15.04	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	53.07	78.80
Dundalk	2	500	11.32	1.64	0.23	0.09	1.96	21.12	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.15	79.05
Durham	6	500	11.59	1.37	0.15	0.06	1.58	19.49	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.52	78.90
Eganville	4	500	10.22	2.32	0.17	0.12	2.61	23.27	24.11	3.39	0.12	-0.06	3.45	41.36	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	61.30	79.20
Erin	21	500	19.72	0.73	0.19	0.08	1.00	24.72	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	62.75	79.00
Exeter	19	500	5.21	1.30	0.15	0.06	1.51	12.76	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	50.79	78.90
Fenelon Falls	10	500	9.43	0.95	0.15	0.08	1.18	15.33	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	53.36	79.00
Forest	7	500	11.98	1.18	0.16	0.06	1.40	18.98	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.01	78.90
GBE	48	500	4.92	1.14	0.16	0.06	1.36	11.72	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	49.75	78.90
Georgina	9	500	8.24	1.62	0.16	0.08	1.86	17.54	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	55.57	79.00
Glencoe	1	500	5.21	0.81	0.22	0.14	1.17	11.06	24.11	3.39	0.14	-0.06	3.47	41.46	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	49.09	79.30
Grand Bend	1	500	10.63	1.23	0.19	0.07	1.49	18.08	24.11	3.39	0.07	-0.06	3.40	41.11	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	56.11	78.95
Hastings	10	500	10.98	1.69	0.23	0.09	2.01	21.03	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.06	79.05
Havelock	3	500	10.63	1.52	0.16	0.09	1.77	19.48	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.51	79.05
Kirkfield	-	500	6.88	1.95	0.61	0.44	3.00	21.88	24.11	3.39	0.44	-0.06	3.77	42.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.91	80.80

Unmtr

May-07

Target Rates

															DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF								
	Number of customers	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62	0.930	0.670	1.0545	1.092	old Other	new Other	Band 1	Band 2	$Chg old	$ Chg new	Total Old Bill	Total New Bill
Lanark Highlands	3	500	8.75	1.99	0.63	0.50	3.12	24.35	24.11	3.39	0.50	-0.06	3.83	43.26	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	62.38	81.10
Larder Lake	1	500	9.62	1.58	0.51	0.36	2.45	21.87	24.11	3.39	0.36	-0.06	3.69	42.56	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.90	80.40
Latchford	-	500	0.97	1.02	0.65	0.20	1.87	10.32	24.11	3.39	0.20	-0.06	3.53	41.76	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	48.35	79.60
Lindsay	71	500	11.50	1.38	0.15	0.06	1.59	19.45	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.48	78.90
Lucan Granton	5	500	8.03	1.47	0.17	0.10	1.74	16.73	24.11	3.39	0.10	-0.06	3.43	41.26	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	54.76	79.10
Malahide	1	500	7.45	1.98	0.81	0.49	3.28	23.85	24.11	3.39	0.49	-0.06	3.82	43.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	61.88	81.05
Mapleton	-	500	10.32	1.71	0.40	0.29	2.40	22.32	24.11	3.39	0.29	-0.06	3.62	42.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	60.35	80.05
Markdale	-	500	11.04	0.80	0.15	0.04	0.99	15.99	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	54.02	78.80
Marmora	10	500	4.54	1.05	0.15	0.05	1.25	10.79	24.11	3.39	0.05	-0.06	3.38	41.01	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	48.82	78.85
McGarry	2	500	9.52	2.00	0.57	0.50	3.07	24.87	24.11	3.39	0.50	-0.06	3.83	43.26	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	62.90	81.10
Meaford	23	500	11.55	1.23	0.16	0.07	1.46	18.85	24.11	3.39	0.07	-0.06	3.40	41.11	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	56.88	78.95
Middlesex Centre	3	500	8.21	1.37	0.44	0.35	2.16	19.01	24.11	3.39	0.35	-0.06	3.68	42.51	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.04	80.35
Napanee	13	500	10.62	1.28	0.16	0.06	1.50	18.12	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	56.15	78.90
Nipigon	3	500	11.19	1.05	0.34	0.21	1.60	19.19	24.11	3.39	0.21	-0.06	3.54	41.81	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.22	79.65
North Dorchester	1	500	7.47	0.90	0.35	0.26	1.51	15.02	24.11	3.39	0.26	-0.06	3.59	42.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	53.05	79.90
North Dundas	12	500	6.29	0.83	0.16	0.04	1.03	11.44	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	49.47	78.80
North Glengarry	6	500	8.40	0.90	0.21	0.12	1.23	14.55	24.11	3.39	0.12	-0.06	3.45	41.36	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	52.58	79.20
North Grenville	8	500	9.74	1.71	0.14	0.08	1.93	19.39	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.42	79.00
North Perth	11	500	14.30	1.00	0.12	0.04	1.16	20.10	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	58.13	78.80
North Stormont	8	500	2.22	0.78	0.37	0.26	1.41	9.27	24.11	3.39	0.26	-0.06	3.59	42.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	47.30	79.90
Omemee	5	500	10.18	1.47	0.18	0.09	1.74	18.88	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	56.91	79.05
Perth	26	500	9.49	0.92	0.13	0.04	1.09	14.94	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	52.97	78.80
Perth East	3	500	6.86	1.29	0.16	0.09	1.54	14.56	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	52.59	79.05
Prince Edward	20	500	10.96	1.42	0.18	0.08	1.68	19.36	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.39	79.00
Quinte West	32	500	1.41	1.05	0.14	0.06	1.25	7.66	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	45.69	78.90
Rainy River	-	500	9.18	1.76	0.45	0.36	2.57	22.03	24.11	3.39	0.36	-0.06	3.69	42.56	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	60.06	80.40
Ramara	2	500	10.02	1.06	0.45	0.37	1.88	19.42	24.11	3.39	0.37	-0.06	3.70	42.61	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.45	80.45
Red Rock	3	500	10.36	1.94	0.27	0.24	2.45	22.61	24.11	3.39	0.24	-0.06	3.57	41.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	60.64	79.80
Rockland	18	500	3.16	1.00	0.17	0.22	1.39	10.11	24.11	3.39	0.22	-0.06	3.55	41.86	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	48.14	79.70
Russell	7	500	9.17	2.24	0.18	0.11	2.53	21.82	24.11	3.39	0.11	-0.06	3.44	41.31	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.85	79.15
Schreiber	5	500	9.88	2.51	0.50	0.40	3.41	26.93	24.11	3.39	0.40	-0.06	3.73	42.76	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	64.96	80.60
Severn	8	500	10.62	1.06	0.31	0.22	1.59	18.57	24.11	3.39	0.22	-0.06	3.55	41.86	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	56.60	79.70
Shelburne	8	500	9.53	0.87	0.10	0.02	0.99	14.48	24.11	3.39	0.02	-0.06	3.35	40.86	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	52.51	78.70
Smiths Falls	15	500	4.46	1.05	0.12	0.04	1.21	10.51	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	48.54	78.80
South Glengarry	1	500	8.25	0.75	0.37	0.30	1.42	15.35	24.11	3.39	0.30	-0.06	3.63	42.26	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	53.38	80.10
South River	1	500	10.59	1.58	0.39	0.30	2.27	21.94	24.11	3.39	0.30	-0.06	3.63	42.26	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.97	80.10
Springwater	5	500	9.80	1.07	0.27	0.17	1.51	17.35	24.11	3.39	0.17	-0.06	3.50	41.61	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	55.38	79.45
Stirling-Rawdon	3	500	11.59	1.30	0.21	0.09	1.60	19.59	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.62	79.05
Thedford	3	500	8.45	1.06	0.36	0.31	1.73	17.10	24.11	3.39	0.31	-0.06	3.64	42.31	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	55.13	80.15
Thessalon	-	500	8.99	1.55	0.10	0.08	1.73	17.64	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	55.67	79.00
Thorndale	3	500	6.79	1.02	0.52	0.32	1.86	16.09	24.11	3.39	0.32	-0.06	3.65	42.36	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	54.12	80.20
Thorold	71	500	10.85	1.50	0.15	0.06	1.71	19.40	24.11	3.39	0.06	-0.06	3.39	41.06	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	57.43	78.90
Tweed	8	500	3.67	0.97	0.43	0.31	1.71	12.22	24.11	3.39	0.31	-0.06	3.64	42.31	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	50.25	80.15
Wardsville	2	500	5.70	1.00	0.25	0.08	1.33	12.35	24.11	3.39	0.08	-0.06	3.41	41.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	50.38	79.00
Warkworth	-	500	10.20	1.52	0.46	0.35	2.33	21.85	24.11	3.39	0.35	-0.06	3.68	42.51	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.88	80.35
West Elgin	4	500	7.23	0.70	0.17	0.07	0.94	11.93	24.11	3.39	0.07	-0.06	3.40	41.11	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	49.96	78.95
Whitchurch Stouff	21	500	10.46	0.93	0.11	0.04	1.08	15.86	24.11	3.39	0.04	-0.06	3.37	40.96	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	53.89	78.80
Wiarton	4	500	11.42	1.89	0.19	0.09	2.17	22.27	24.11	3.39	0.09	-0.06	3.42	41.21	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	60.30	79.05
Woodville	1	500	7.98	1.57	0.67	0.48	2.72	21.58	24.11	3.39	0.48	-0.06	3.81	43.16	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	59.61	81.00
Wyoming	3	500	8.22	1.45	0.16	0.07	1.68	16.62	24.11	3.39	0.07	-0.06	3.40	41.11	0.70	0.62	0.93	0.67	1.0545	1.092	11.67	10.54	500	-	26.4	27.3	54.65	78.95
Terrace Bay	8	500	20.53	1.29	0.82		2.11	31.08	24.11	3.39		-0.06	3.33	40.76	0.70	0.62	0.47	0.67	1.0426	1.092	9.18	10.54	500	-	26.1	27.3	66.33	78.60
	4,923																											

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	% Impact	$ Impact		Dx Basic c	Dx Basic N	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr	$ incr	Wted Cust	Dx Basic	Dx New	Total Bill new no new RTSR	Total Bill new
G1	2.0%	1.51	G1	37.76	41.04	8.7%	38.66	41.21	6.6%	77.54	80.09	3.3%	77.54	79.05	2.0%	1.51	0.74	6.4%	4.9%	2.4%	1.4%
G3	31.8%	19.04	G3	21.64	41.04	89.7%	21.99	41.01	86.5%	59.81	79.61	33.1%	59.81	78.85	31.8%	19.04	0.00	0.3%	0.2%	0.1%	0.1%
UG	46.9%	25.14	UG	14.49	41.04	183.3%	14.79	40.91	176.6%	53.62	79.74	48.7%	53.62	78.75	46.9%	25.14	0.08	14.6%	14.1%	3.9%	3.7%
Ailsa Craig	46.0%	24.92	Ailsa Craig	14.80	41.04	177.3%	16.10	41.21	156.0%	54.13	80.18	48.1%	54.13	79.05	46.0%	24.92	0.00	0.1%	0.1%	0.0%	0.0%
Arkona	68.1%	32.58	Arkona	5.44	41.04	654.5%	9.79	42.56	334.7%	47.82	81.53	70.5%	47.82	80.40	68.1%	32.58	0.00	0.3%	0.1%	0.0%	0.0%
Arnprior	42.9%	23.69	Arnprior	16.08	41.04	155.2%	17.18	41.06	139.0%	55.21	80.03	44.9%	55.21	78.90	42.9%	23.69	0.00	0.7%	0.6%	0.2%	0.2%
Arran-Elderslie	63.2%	30.62	Arran-Elderslie	9.10	41.04	351.0%	10.40	41.21	296.2%	48.43	80.18	65.5%	48.43	79.05	63.2%	30.62	0.00	0.6%	0.5%	0.1%	0.1%
Artemesia	33.3%	20.08	Artemesia	18.04	41.04	127.5%	22.19	42.46	91.3%	60.22	81.43	35.2%	60.22	80.30	33.3%	20.08	0.00	0.2%	0.1%	0.1%	0.1%
Bancroft	38.8%	22.09	Bancroft	17.63	41.04	132.8%	18.88	41.16	118.0%	56.91	80.13	40.8%	56.91	79.00	38.8%	22.09	0.00	0.1%	0.1%	0.0%	0.0%
Bath	50.9%	26.91	Bath	12.21	41.04	236.1%	14.86	41.96	182.4%	52.89	80.93	53.0%	52.89	79.80	50.9%	26.91	0.00	0.1%	0.1%	0.0%	0.0%
Blandford-Blenhei	38.2%	22.01	Blandford-Blenheim	17.16	41.04	139.2%	19.56	41.76	113.5%	57.59	80.73	40.2%	57.59	79.60	38.2%	22.01	0.00	0.3%	0.3%	0.1%	0.1%
Blyth	42.3%	23.67	Blyth	15.60	41.04	163.1%	17.90	41.76	133.3%	55.93	80.73	44.3%	55.93	79.60	42.3%	23.67	-	0.0%	0.0%	0.0%	0.0%
Bobcaygeon	37.7%	21.63	Bobcaygeon	18.04	41.04	127.5%	19.39	41.21	112.5%	57.42	80.18	39.6%	57.42	79.05	37.7%	21.63	0.00	0.5%	0.4%	0.1%	0.1%
Brighton	38.2%	21.83	Brighton	17.74	41.04	131.4%	19.14	41.16	115.0%	57.17	80.13	40.2%	57.17	79.00	38.2%	21.83	0.00	0.1%	0.1%	0.0%	0.0%
Brockville	48.3%	25.65	Brockville	14.27	41.04	187.6%	15.12	40.96	170.9%	53.15	79.93	50.4%	53.15	78.80	48.3%	25.65	0.01	1.5%	1.4%	0.4%	0.4%
Caledon OH 01			Caledon OH 01																		
Caledon CH 02			Caledon CH 02																		
Caledon OH 06			Caledon OH 06																		
Caledon OH 07			Caledon OH 07																		
Caledon CH			Caledon CH																		
Caledon GS 05	27.8%	17.32	Caledon GS 05	22.15	41.04	85.3%	24.25	41.76	72.2%	62.28	80.73	29.6%	62.28	79.60	27.8%	17.32	0.02	1.5%	1.2%	0.5%	0.5%
Caledon OH			Caledon OH																		
Caledon Large Us			Caledon Large User																		
Campbellford-Sey	49.6%	26.14	Campbellford-Seymour	13.58	41.04	202.2%	14.68	41.01	179.4%	52.71	79.98	51.7%	52.71	78.85	49.6%	26.14	0.00	0.5%	0.4%	0.1%	0.1%
Carleton Place	34.3%	20.16	Carleton Place	19.76	41.04	107.7%	20.76	41.11	98.0%	58.79	80.08	36.2%	58.79	78.95	34.3%	20.16	0.01	0.7%	0.6%	0.2%	0.2%
Cavan-Millbrook-N	35.1%	20.74	Cavan-Millbrook-North Mor	18.18	41.04	125.8%	21.13	42.06	99.1%	59.16	81.03	37.0%	59.16	79.90	35.1%	20.74	0.00	0.1%	0.1%	0.0%	0.0%
Centre Hastings	50.0%	26.29	Centre Hastings													-	0.00	0.0%	0.0%	0.0%	0.0%
Chalk River	32.0%	19.47	Chalk River	19.15	41.04	114.3%	22.80	42.46	86.2%	60.83	81.43	33.9%	60.83	80.30	32.0%	19.47	0.00	0.0%	0.0%	0.0%	0.0%
Champlain	45.7%	24.89	Champlain	14.38	41.04	185.4%	16.43	41.51	152.6%	54.46	80.48	47.8%	54.46	79.35	45.7%	24.89	0.00	0.4%	0.3%	0.1%	0.1%
Cobden	28.2%	17.62	Cobden	21.15	41.04	94.1%	24.45	42.26	72.8%	62.48	81.23	30.0%	62.48	80.10	28.2%	17.62	0.00	0.2%	0.1%	0.0%	0.0%
Deep River	27.3%	17.02	Deep River	22.80	41.04	80.0%	24.25	41.46	71.0%	62.28	80.43	29.1%	62.28	79.30	27.3%	17.02	0.00	0.0%	0.0%	0.0%	0.0%
Deseronto	56.8%	28.56	Deseronto	11.36	41.04	261.3%	12.26	41.01	234.5%	50.29	79.98	59.0%	50.29	78.85	56.8%	28.56	0.00	0.2%	0.1%	0.0%	0.0%
Dryden	48.5%	25.73	Dryden	14.24	41.04	188.2%	15.04	40.96	172.3%	53.07	79.93	50.6%	53.07	78.80	48.5%	25.73	0.00	0.2%	0.1%	0.0%	0.0%
Dundalk	33.6%	19.90	Dundalk	19.52	41.04	110.3%	21.12	41.21	95.1%	59.15	80.18	35.5%	59.15	79.05	33.6%	19.90	0.00	0.0%	0.0%	0.0%	0.0%
Durham	37.2%	21.38	Durham	18.44	41.04	122.6%	19.49	41.06	110.7%	57.52	80.03	39.1%	57.52	78.90	37.2%	21.38	0.00	0.1%	0.1%	0.0%	0.0%
Eganville	29.2%	17.90	Eganville	21.82	41.04	88.1%	23.27	41.36	77.7%	61.30	80.33	31.0%	61.30	79.20	29.2%	17.90	0.00	0.1%	0.1%	0.0%	0.0%
Erin	25.9%	16.25	Erin	23.37	41.04	75.6%	24.72	41.16	66.5%	62.75	80.13	27.7%	62.75	79.00	25.9%	16.25	0.00	0.3%	0.3%	0.1%	0.1%
Exeter	55.3%	28.11	Exeter	11.71	41.04	250.5%	12.76	41.06	221.8%	50.79	80.03	57.6%	50.79	78.90	55.3%	28.11	0.00	1.0%	0.9%	0.2%	0.2%
Fenelon Falls	48.0%	25.64	Fenelon Falls	14.18	41.04	189.4%	15.33	41.16	168.5%	53.36	80.13	50.2%	53.36	79.00	48.0%	25.64	0.00	0.4%	0.3%	0.1%	0.1%
Forest	38.4%	21.89	Forest	17.88	41.04	129.5%	18.98	41.06	116.3%	57.01	80.03	40.4%	57.01	78.90	38.4%	21.89	0.00	0.2%	0.2%	0.1%	0.1%
GBE	58.6%	29.15	GBE	10.62	41.04	286.5%	11.72	41.06	250.3%	49.75	80.03	60.9%	49.75	78.90	58.6%	29.15	0.01	2.8%	2.4%	0.6%	0.6%
Georgina	42.2%	23.43	Georgina	16.34	41.04	151.2%	17.54	41.16	134.7%	55.57	80.13	44.2%	55.57	79.00	42.2%	23.43	0.00	0.3%	0.2%	0.1%	0.1%
Glencoe	61.5%	30.21	Glencoe	9.26	41.04	343.2%	11.06	41.46	274.9%	49.09	80.43	63.8%	49.09	79.30	61.5%	30.21	0.00	0.1%	0.1%	0.0%	0.0%
Grand Bend	40.7%	22.84	Grand Bend	16.78	41.04	144.6%	18.08	41.11	127.4%	56.11	80.08	42.7%	56.11	78.95	40.7%	22.84	0.00	0.0%	0.0%	0.0%	0.0%
Hastings	33.8%	19.99	Hastings	19.43	41.04	111.2%	21.03	41.21	96.0%	59.06	80.18	35.8%	59.06	79.05	33.8%	19.99	0.00	0.2%	0.2%	0.1%	0.1%
Havelock	37.4%	21.54	Havelock	18.23	41.04	125.1%	19.48	41.21	111.5%	57.51	80.18	39.4%	57.51	79.05	37.4%	21.54	0.00	0.1%	0.1%	0.0%	0.0%
Kirkfield	34.9%	20.89	Kirkfield	16.63	41.04	146.8%	21.88	42.96	96.3%	59.91	81.93	36.7%	59.91	80.80	34.9%	20.89	-	0.0%	0.0%	0.0%	0.0%

	% Impact	$ Impact		Dx Basic c	Dx Basic N	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr	$ incr	Wted Cust	Dx Basic	Dx New	Total Bill new no new RTSR	Total Bill new
Lanark Highlands	30.0%	18.72	Lanark Highlands	18.70	41.04	119.5%	24.35	43.26	77.7%	62.38	82.23	31.8%	62.38	81.10	30.0%	18.72	0.00	0.1%	0.0%	0.0%	0.0%
Larder Lake	34.2%	20.50	Larder Lake	17.52	41.04	134.3%	21.87	42.56	94.6%	59.90	81.53	36.1%	59.90	80.40	34.2%	20.50	0.00	0.0%	0.0%	0.0%	0.0%
Latchford	64.6%	31.25	Latchford	6.07	41.04	576.2%	10.32	41.76	304.6%	48.35	80.73	67.0%	48.35	79.60	64.6%	31.25	-	0.0%	0.0%	0.0%	0.0%
Lindsay	37.3%	21.42	Lindsay	18.40	41.04	123.1%	19.45	41.06	111.1%	57.48	80.03	39.2%	57.48	78.90	37.3%	21.42	0.01	1.8%	1.6%	0.6%	0.5%
Lucan Granton	44.4%	24.34	Lucan Granton	15.38	41.04	166.9%	16.73	41.26	146.6%	54.76	80.23	46.5%	54.76	79.10	44.4%	24.34	0.00	0.2%	0.1%	0.0%	0.0%
Malahide	31.0%	19.17	Malahide	17.35	41.04	136.6%	23.85	43.21	81.2%	61.88	82.18	32.8%	61.88	81.05	31.0%	19.17	0.00	0.0%	0.0%	0.0%	0.0%
Mapleton	32.6%	19.70	Mapleton	18.87	41.04	117.5%	22.32	42.21	89.1%	60.35	81.18	34.5%	60.35	80.05	32.6%	19.70	-	0.0%	0.0%	0.0%	0.0%
Markdale	45.9%	24.78	Markdale	15.04	41.04	172.9%	15.99	40.96	156.2%	54.02	79.93	48.0%	54.02	78.80	45.9%	24.78	-	0.0%	0.0%	0.0%	0.0%
Marmora	61.5%	30.03	Marmora	9.79	41.04	319.2%	10.79	41.01	280.1%	48.82	79.98	63.8%	48.82	78.85	61.5%	30.03	0.00	0.6%	0.6%	0.1%	0.1%
McGarry	28.9%	18.20	McGarry	19.52	41.04	110.3%	24.87	43.26	73.9%	62.90	82.23	30.7%	62.90	81.10	28.9%	18.20	0.00	0.0%	0.0%	0.0%	0.0%
Meaford	38.8%	22.07	Meaford	17.70	41.04	131.9%	18.85	41.11	118.1%	56.88	80.08	40.8%	56.88	78.95	38.8%	22.07	0.00	0.6%	0.6%	0.2%	0.2%
Middlesex Centre	40.9%	23.31	Middlesex Centre	15.06	41.04	172.5%	19.01	42.51	123.6%	57.04	81.48	42.8%	57.04	80.35	40.9%	23.31	0.00	0.1%	0.1%	0.0%	0.0%
Napanee	40.5%	22.75	Napanee	17.02	41.04	141.1%	18.12	41.06	126.6%	56.15	80.03	42.5%	56.15	78.90	40.5%	22.75	0.00	0.4%	0.3%	0.1%	0.1%
Nipigon	39.2%	22.43	Nipigon	16.44	41.04	149.7%	19.19	41.81	117.9%	57.22	80.78	41.2%	57.22	79.65	39.2%	22.43	0.00	0.1%	0.1%	0.0%	0.0%
North Dorchester	50.6%	26.85	North Dorchester	11.97	41.04	242.9%	15.02	42.06	180.0%	53.05	81.03	52.7%	53.05	79.90	50.6%	26.85	0.00	0.0%	0.0%	0.0%	0.0%
North Dundas	59.3%	29.33	North Dundas	10.44	41.04	293.1%	11.44	40.96	258.0%	49.47	79.93	61.6%	49.47	78.80	59.3%	29.33	0.00	0.7%	0.6%	0.2%	0.1%
North Glengarry	50.6%	26.62	North Glengarry	12.90	41.04	218.2%	14.55	41.36	184.3%	52.58	80.33	52.8%	52.58	79.20	50.6%	26.62	0.00	0.3%	0.2%	0.1%	0.1%
North Grenville	37.6%	21.58	North Grenville	18.29	41.04	124.4%	19.39	41.16	112.3%	57.42	80.13	39.5%	57.42	79.00	37.6%	21.58	0.00	0.2%	0.2%	0.1%	0.1%
North Perth	35.6%	20.67	North Perth	19.30	41.04	112.7%	20.10	40.96	103.8%	58.13	79.93	37.5%	58.13	78.80	35.6%	20.67	0.00	0.3%	0.2%	0.1%	0.1%
North Stormont	68.9%	32.60	North Stormont	6.12	41.04	570.6%	9.27	42.06	353.7%	47.30	81.03	71.3%	47.30	79.90	68.9%	32.60	0.00	0.9%	0.6%	0.1%	0.1%
Omemee	38.9%	22.14	Omemee	17.53	41.04	134.1%	18.88	41.21	118.3%	56.91	80.18	40.9%	56.91	79.05	38.9%	22.14	0.00	0.1%	0.1%	0.0%	0.0%
Perth	48.8%	25.83	Perth	14.09	41.04	191.3%	14.94	40.96	174.2%	52.97	79.93	50.9%	52.97	78.80	48.8%	25.83	0.01	1.0%	0.9%	0.3%	0.3%
Perth East	50.3%	26.46	Perth East	13.31	41.04	208.4%	14.56	41.21	183.0%	52.59	80.18	52.5%	52.59	79.05	50.3%	26.46	0.00	0.1%	0.1%	0.0%	0.0%
Prince Edward	37.6%	21.61	Prince Edward	18.06	41.04	127.3%	19.36	41.16	112.6%	57.39	80.13	39.6%	57.39	79.00	37.6%	21.61	0.00	0.5%	0.5%	0.2%	0.2%
Quinte West	72.7%	33.21	Quinte West	6.66	41.04	516.3%	7.66	41.06	436.0%	45.69	80.03	75.1%	45.69	78.90	72.7%	33.21	0.01	3.4%	2.8%	0.5%	0.5%
Rainy River	33.9%	20.34	Rainy River	17.98	41.04	128.3%	22.03	42.56	93.2%	60.06	81.53	35.7%	60.06	80.40	33.9%	20.34	-	0.0%	0.0%	0.0%	0.0%
Ramara	40.0%	23.00	Ramara	15.32	41.04	167.9%	19.42	42.61	119.4%	57.45	81.58	42.0%	57.45	80.45	40.0%	23.00	0.00	0.1%	0.0%	0.0%	0.0%
Red Rock	31.6%	19.16	Red Rock	20.06	41.04	104.6%	22.61	41.96	85.6%	60.64	80.93	33.5%	60.64	79.80	31.6%	19.16	0.00	0.1%	0.1%	0.0%	0.0%
Rockland	65.5%	31.56	Rockland	8.16	41.04	403.0%	10.11	41.86	314.0%	48.14	80.83	67.9%	48.14	79.70	65.5%	31.56	0.00	1.5%	1.1%	0.2%	0.2%
Russell	32.2%	19.30	Russell	20.37	41.04	101.5%	21.82	41.31	89.3%	59.85	80.28	34.1%	59.85	79.15	32.2%	19.30	0.00	0.1%	0.1%	0.0%	0.0%
Schreiber	24.1%	15.64	Schreiber	22.43	41.04	83.0%	26.93	42.76	58.8%	64.96	81.73	25.8%	64.96	80.60	24.1%	15.64	0.00	0.1%	0.1%	0.0%	0.0%
Severn	40.8%	23.10	Severn	15.92	41.04	157.8%	18.57	41.86	125.4%	56.60	80.83	42.8%	56.60	79.70	40.8%	23.10	0.00	0.3%	0.2%	0.1%	0.1%
Shelburne	49.9%	26.19	Shelburne	13.88	41.04	195.7%	14.48	40.86	182.2%	52.51	79.83	52.0%	52.51	78.70	49.9%	26.19	0.00	0.3%	0.3%	0.1%	0.1%
Smiths Falls	62.3%	30.26	Smiths Falls	9.71	41.04	322.7%	10.51	40.96	289.7%	48.54	79.93	64.7%	48.54	78.80	62.3%	30.26	0.00	1.0%	0.9%	0.2%	0.2%
South Glengarry	50.0%	26.72	South Glengarry	12.00	41.04	242.0%	15.35	42.26	175.3%	53.38	81.23	52.2%	53.38	80.10	50.0%	26.72	0.00	0.0%	0.0%	0.0%	0.0%
South River	33.6%	20.13	South River	18.49	41.04	122.0%	21.94	42.26	92.6%	59.97	81.23	35.4%	59.97	80.10	33.6%	20.13	0.00	0.0%	0.0%	0.0%	0.0%
Springwater	43.5%	24.07	Springwater	15.15	41.04	170.9%	17.35	41.61	139.8%	55.38	80.58	45.5%	55.38	79.45	43.5%	24.07	0.00	0.2%	0.1%	0.0%	0.0%
Stirling-Rawdon	37.2%	21.43	Stirling-Rawdon	18.09	41.04	126.9%	19.59	41.21	110.4%	57.62	80.18	39.1%	57.62	79.05	37.2%	21.43	0.00	0.1%	0.1%	0.0%	0.0%
Thedford	45.4%	25.02	Thedford	13.75	41.04	198.5%	17.10	42.31	147.4%	55.13	81.28	47.4%	55.13	80.15	45.4%	25.02	0.00	0.1%	0.1%	0.0%	0.0%
Thessalon	41.9%	23.33	Thessalon	16.74	41.04	145.2%	17.64	41.16	133.3%	55.67	80.13	43.9%	55.67	79.00	41.9%	23.33	-	0.0%	0.0%	0.0%	0.0%
Thorndale	48.2%	26.08	Thorndale	11.89	41.04	245.2%	16.09	42.36	163.3%	54.12	81.33	50.3%	54.12	80.20	48.2%	26.08	0.00	0.1%	0.1%	0.0%	0.0%
Thorold	37.4%	21.47	Thorold	18.35	41.04	123.7%	19.40	41.06	111.6%	57.43	80.03	39.3%	57.43	78.90	37.4%	21.47	0.01	1.8%	1.6%	0.6%	0.5%
Tweed	59.5%	29.90	Tweed	8.52	41.04	381.7%	12.22	42.31	246.2%	50.25	81.28	61.7%	50.25	80.15	59.5%	29.90	0.00	0.6%	0.4%	0.1%	0.1%
Wardsville	56.8%	28.62	Wardsville	10.70	41.04	283.6%	12.35	41.16	233.3%	50.38	80.13	59.0%	50.38	79.00	56.8%	28.62	0.00	0.1%	0.1%	0.0%	0.0%
Warkworth	34.2%	20.47	Warkworth	17.80	41.04	130.6%	21.85	42.51	94.6%	59.88	81.48	36.1%	59.88	80.35	34.2%	20.47	-	0.0%	0.0%	0.0%	0.0%
West Elgin	58.0%	28.99	West Elgin	10.73	41.04	282.5%	11.93	41.11	244.6%	49.96	80.08	60.3%	49.96	78.95	58.0%	28.99	0.00	0.2%	0.2%	0.0%	0.0%
Whitchurch Stouff	46.2%	24.91	Whitchurch Stouffville	15.11	41.04	171.6%	15.86	40.96	158.3%	53.89	79.93	48.3%	53.89	78.80	46.2%	24.91	0.00	0.7%	0.7%	0.2%	0.2%
Wiarton	31.1%	18.75	Wiarton	20.87	41.04	96.7%	22.27	41.21	85.0%	60.30	80.18	33.0%	60.30	79.05	31.1%	18.75	0.00	0.1%	0.1%	0.0%	0.0%
Woodville	35.9%	21.39	Woodville	15.83	41.04	159.3%	21.58	43.16	100.0%	59.61	82.13	37.8%	59.61	81.00	35.9%	21.39	0.00	0.0%	0.0%	0.0%	0.0%
Wyoming	44.5%	24.30	Wyoming	15.47	41.04	165.3%	16.62	41.11	147.4%	54.65	80.08	46.5%	54.65	78.95	44.5%	24.30	0.00	0.1%	0.1%	0.0%	0.0%
Terrace Bay	18.5%	12.28	Terrace Bay	26.98	41.04	52.1%	31.08	40.76	31.1%	66.33	77.24	16.5%	66.33	78.60	18.5%	12.28					
																		54.1%	47.2%	14.5%	13.0%

5.2

				May 07 Rates						Target Rates						**DRC**	**WMSC**	**Old RTSR**	**New RTSR**	**Old TLF**	**New TLF**		Commodity	
	kWh	kW	LF	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		2.110		1.061	old Other	new Other	Band 1	Band 2
	43,164												-0.22											
F1	43,164	133	0.45	60.71	7.06	0.26	0.31	7.63	1,077	46.75	9.22	0.31	-0.22	9.31	1,287	0.70	0.62	2.83	2.11	1.0920	1.061	1,006	884	-	43,164
F3	43,164	133	0.45	53.91	10.87	0.10	0.16	11.13	1,537	46.75	9.22	0.16	-0.22	9.16	1,267	0.70	0.62	3.13	2.11	1.0610	1.061	1,028	884	-	43,164
F1	43,164	133	0.45	28.61	7.06	0.26	0.31	7.63	1,045	46.75	9.22	0.31	-0.22	9.31	1,287	0.70	0.62	2.83	2.11	1.0920	1.061	1,006	884	-	43,164
F3	43,164	133	0.45	30.16	10.87	0.10	0.16	11.13	1,513	46.75	9.22	0.16	-0.22	9.16	1,267	0.70	0.62	3.13	2.11	1.0610	1.061	1,028	884	-	43,164
G1	43,164	133	0.45	36.02	9.59	0.26	0.29	10.14	1,387	46.75	9.22	0.29	-0.22	9.29	1,285	0.70	0.62	2.62	2.11	1.0920	1.061	975	884	-	43,164
G3	43,164	133	0.45	46.75	9.91	0.08	0.15	10.14	1,398	46.75	9.22	0.15	-0.22	9.15	1,266	0.70	0.62	2.75	2.11	1.0610	1.061	975	884	-	43,164
T	43,164	133	0.45	261.54	8.16	0.04	0.09	8.29	1,366	46.75	9.22	0.09	-0.22	9.09	1,258	0.70	0.62	2.82	2.11	1.0610	1.061	984	884	-	43,164

	$Chg old	$ Chg new	Total Old Bill	Total New Bill		Dx Basic (	Dx Basic I	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
F1	2,451.0	2,381.4	4,534.13	4,553.08	F1 nRRA	1,001.25	1,274.98	27.3%	1,077.19	1,287.33	19.5%	4,534.13	4,674.69	3.1%	4,534.13	4,553.08	0.4%
F3	2,381.4	2,381.4	4,946.45	4,533.10	F3 nRRA	1,502.02	1,274.98	-15.1%	1,536.66	1,267.35	-17.5%	4,946.45	4,677.13	-5.4%	4,946.45	4,533.10	-8.4%
F1	2,451.0	2,381.4	4,502.03	4,553.08	F1 wRRA	969.15	1,274.98	31.6%	1,045.09	1,287.33	23.2%	4,502.03	4,674.69	3.8%	4,502.03	4,553.08	1.1%
F3	2,381.4	2,381.4	4,922.70	4,533.10	F3 wRRA	1,478.27	1,274.98	-13.8%	1,512.91	1,267.35	-16.2%	4,922.70	4,677.13	-5.0%	4,922.70	4,533.10	-7.9%
G1	2,451.0	2,381.4	4,813.28	4,550.42	G1	1,313.61	1,274.98	-2.9%	1,386.88	1,284.66	-7.4%	4,813.28	4,641.48	-3.6%	4,813.28	4,550.42	-5.5%
G3	2,381.4	2,381.4	4,754.11	4,531.77	G3	1,366.97	1,274.98	-6.7%	1,397.61	1,266.01	-9.4%	4,754.11	4,622.51	-2.8%	4,754.11	4,531.77	-4.7%
T	2,381.4	2,381.4	4,731.63	4,523.77	T	1,348.62	1,274.98	-5.5%	1,365.94	1,258.02	-7.9%	4,731.63	4,623.71	-2.3%	4,731.63	4,523.77	-4.4%

5 5.9 750

	May 07 Rates									Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF			Commodity		
	kWh	kW	LF	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62		0.480			1.061	old Other	new Other	Band	Band 2	$Chg old
					[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]										c/kWh	$/kW							
G3	35,000	90	54%	46.75	9.91	0.08	0.15	10.14	957	36.66	7.07	0.15	-0.04	7.18	681	0.70	0.62	2.75	0.48	1.0610	1.061	737	521	750	34,250	2,184.2
T	7,700	200	5%	261.54	8.16	0.04	0.09	8.29	1,921	36.66	7.07	0.09	-0.04	7.12	1,461	0.70	0.62	2.82	0.48	1.0610	1.061	703	206	750	6,950	475.3
G3	802	8	14%	46.75	3.07	0.02	0.05	3.14	72	36.66	7.07	0.15	-0.04	7.18	95	0.70	0.62	0.85	0.48	1.0610	1.061	18.1	15	750	52	43.5
T	846	26	5%	261.54	2.43	0.01	0.03	2.47	282	36.66	7.07	0.09	-0.04	7.12	221	0.70	0.62	0.84	0.48	1.0610	1.061	19.0	25	750	96	46.2
Eganville	6	1	1%	21.35	2.32	0.17	0.12	2.61	22	36.66	7.07	0.37	-0.04	7.40	46	0.70	0.62	0.93	0.48	1.0545	1.061	0.1	0.7	6	-	0.3

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	$ Chg new	Total Old Bill	Total New Bill		Dx Basic old	Dx Basic I	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
G3	2,184.2	3,878.09	3,385.70	G3d	935.99	670.88	-28.3%	956.63	680.55	-28.9%	3,878.09	3,602.01	-7.1%	3,878.09	3,385.70	-12.7%
T	475.3	3,098.46	2,142.37	Td	1,894.51	1,451.08	-23.4%	1,920.52	1,460.64	-23.9%	3,098.46	2,638.58	-14.8%	3,098.46	2,142.37	-30.9%
								-	-		-	-				
G3	43.5	133.52	153.70	G3e	71.37	94.32	32.2%	71.93	95.20	32.3%	133.52	156.78	17.4%	133.52	153.70	15.1%
T	46.2	347.69	292.32	Te	282.10	220.15	-22.0%	282.44	221.39	-21.6%	347.69	286.64	-17.6%	347.69	292.32	-15.9%
								-	-		-	-				
Eganville	0.3	21.96	46.53	GS Eganville	21.49	45.13	110.0%	21.51	45.52	111.7%	21.96	45.98	109.3%	21.96	46.53	111.9%

Lgts

				May-07						Target Rates						DRC	WMSC	Old RTSR	New RTSR	Old TLF	New TLF		
	kWh 2008	Number of customers	kWh	Sr Chg	Base	Rider 1	Rider 2	Total Var Chg	Total Month	Sr Chg	Base	Rider 2	Rider 3	Total Var Chg	Total Month	0.7	0.62	0.530	0.540	1.0920	1.092	old Other	new Other
St Lgt	120,597,533	4,800	1,440		3.96	0.01	0.06	4.03	58.03	1.00	4.57	0.060	(0.08)	4.55	66.48	0.70	0.62	0.53	0.54	1.0920	1.092	28.16	28.32
			=72 kWh x 20 Connections per Acnt																				

				$/kW Based Dx Charges					c/kWh Based Dx Charges														
	Ave Wattage	Connections	kWh est		$/kW	$/kW	$/kW			c/kWh	c/kWh	c/kWh						$/kW	c/kWh				
Terrace Bay	68,000	366	24,480.0	1.36	4.219	2.948	7.17	985.12	1.00	4.57	(0.08)	4.49	1,464.50	0.7	0.62	1.4416	0.540	1.0426	1.092	431.81	481.45
Terrace Bay	186	1	67.1	1.36	4.219	2.948	7.17	2.70	1.00	4.57	(0.08)	4.49	4.01	0.7	0.62	1.4416	0.540	1.0426	1.092	1.18	1.32
Sent Lgt	22,417,163	29,300	62		3.96	0.01	0.06	4.03	2.50	1.00	5.30	0.060	(0.08)	5.27	4.27	0.70	0.62	0.53	0.54	1.0920	1.092	1.21	1.22

	5	5.9	600																			
	Commodity																					
	Band 1	Band 2	$Chg old	$ Chg new	Total Old Bill	Total New Bill	% Impact	$ Impact		Dx Basic old	Dx Basic New	% Incr	Dx old	Dx New	% Incr	Total Bill Old	Total Bill new no new RTSR	% Incr	Total Bill Old	Total Bill new	% Incr
St Lgt	600	840	87.4	87.4	173.57	182.18	5.0%	8.61	Street Lgts	57.02	66.77	17.1%	58.03	66.48	14.6%	173.57	182.02	4.9%	173.57	182.18	5.0%
Terrace Bay	600	23,880	1,500.4	1,571.8	2,917.37	3,517.75	20.6%	600.38		784.65	1,484.12	89.1%	985.12	1,464.50	48.7%	2,917.37	3,396.75	16.4%	2,917.37	3,517.75	20.6%
Terrace Bay	67	-	3.5	3.7	7.38	8.99	21.9%	1.62	Terrace Bay	2.15	4.06	89.4%	2.70	4.01	48.8%	7.38	8.69	17.8%	7.38	8.99	21.9%
Sent Lgt	62	-	3.4	3.4	7.10	8.87	25.0%	1.78	Sentinel Lgts	2.46	4.28	74.5%	2.50	4.27	70.9%	7.10	8.87	25.0%	7.10	8.87	25.0%

School Energy Coalition (SEC) INTERROGATORY #11 List 2

Interrogatory

Ref: G1/7/2, Bill Impacts Acquired LDC Customers

a. Pg. 4-9. Please disaggregate the distribution bill impacts further for GS<50 and GS>50 to separate out i) the increase in the Company's revenue requirement proposed, ii) the changes in regulatory asset rate riders, iii) the impact of harmonization in 2008, and iv) the impact of over or under-contribution to revenue requirement by the class.

Response

The request to disaggregate the distribution bill impacts of Exhibit G1, Tab 7, Schedule 1, Table 1, into the (1) revenue requirement, (2) regulatory asset rate rider, (3) harmonization and the (4) impact of over or under-contribution to the class revenue requirement per class cannot be completely done. Only the first two requests are possible without a new run of the Cost Allocation Model with new rate classes and associated allocators.

(1) The revenue requirement impact is 6.7% [Total Revenue Requirement of $1,067M less $42.3M of Miscellaneous Revenue divided by $960M in estimated revenue from existing rates on 2008 projected volumes]. The listed impacts in Column 1 per Rate Class can be reduced by 6.7% to remove the Revenue Requirement component.

(2) The regulatory asset rate rider impact can be ascertained using the difference in the first two columns of the table per rate class. That is, the difference in the listed impacts of "Basic Distribution Bill Only" in Column 1 and "Distribution Bill incl Riders" in Column 2, per rate class.

(3) The impacts of Harmonization cannot be isolated from that of the Over and Under-Contribution of item (4).

(4) The impact of Over and Under-Collection, that is, at a Revenue-to-Cost ratio of above or below 1, respectively cannot be isolated from the Harmonization impacts without another Model run with new rate classes. The Class Revenue-to-Cost Ratio is based on the Harmonized Class where each Acquired distributor is mapped to. To isolate out the impacts of the Revenue-to-Cost ratios from the Harmonization would require that each Acquired distributor be treated as three separate rate classes each, [residential, small and large general service], and new

Revenue-to-Cost Ratios would need to be developed without the Harmonization impacts.

School Energy Coalition (SEC) INTERROGATORY #12 List 2

Interrogatory

Ref: G1/10/1, Total Loss Factors

a. Pg. 3. Please confirm that, under the Company's proposal, all Acquired LDC customers will have an increase in their TLF. Please add columns to the Table of loss factors showing i) the increase in the TLF for the Acquired customers in each class, ii) the estimated total dollar cost to the Acquired customers in that class of the increase in TLF, and iii) the average percentage bill impact of the TLF increase.

b. Pg. 3. Please provide any information in the Company's possession relating to the actual loss factors experienced within the Acquired service territories, or the relative loss factors in the Acquired service territories vs. the Legacy territory.

c. Pg. 3. Please advise whether the impact of TLF changes was included in the mitigation calculations, and, if so, in what manner was that done?

Response

a. Not all Acquired customers will experience a TLF increase. Those customers mapping to the proposed ST class will see a decrease. The estimated increase on total bill is 1.1%.

	TLF old	TLF new	$ Incr	% Incr
UR	1.0545	1.078	$ 922,363	1.35%
R1	1.0545	1.085	$1,780,759	1.70%
R2	1.0545	1.092	$ 351,736	2.11%
Seasonal	1.0545	1.092	$ 5,548	1.57%
Uge	1.0545	1.092	$ 526,830	2.49%
Ugd	1.0545	1.061	$ 133,391	0.44%
Gse	1.0545	1.092	$1,040,211	2.08%
GSd	1.0545	1.061	$ 282,916	0.40%
Dgen	1.0545	1.061	$ -	0.00%
ST	1.0045 to 1.0545	1.034	$ (145,213)	-0.20%
			$4,898,541	1.11%

b. No such information exists.

c. Yes, the average total bill impacts calculated has assumed the existing bill on old TLF and new bill on new TLF. All mitigation impacts used this change in TLF assumption.

School Energy Coalition (SEC) INTERROGATORY #13 List 2

Interrogatory

Ref: G2/2/1, Harmonization of Acquired LDC Customers

a. Pg. 12. Please confirm that, in the examples in Table 7, the existing volumetric charge is not part of the calculation of the harmonized rates. Please confirm that the bill impacts to customers in the Acquired LDCs that have identical existing monthly fixed charges will vary depending on their existing monthly volumetric charges. Please confirm that by increasing the volumetric charges in all cases to the same amount, the result is that customers with existing high fixed charges may see their existing overcontribution increased during the harmonization period, until, their fixed charge can be reduced to be in line with the new volumetric charge already imposed.

b. Pg. 15. Please restate Tables 8, 9 and 10 on the basis of distribution bills only.

c. Pg. 15. Please provide, for each Impact Range in Tables 8, 9 and 10, the total dollar increase anticipated over the harmonization period for the customers in that Impact Range, e.g. 1115 UGSe customers in the Impact Range of 4% to 6% will, by the end of the harmonization plan, be paying an aggregate of $X more than they are paying today.

d. Pg. 15. Please advise whether the impacts in Tables 8, 9 and 10 include the change in total loss factors and, if so, how those changes were taken into account.

e. Please advise whether the data on former pages 11 through 26 of 28 was incorrect, or is correct but was replaced due to a change in presentation.

Response

a. The confirmations requested are listed below:
- The existing variable charge is not used in the Harmonization rates calculation, only the existing service charge.
- The bill impacts of Acquired distributors who have the same service charge but different variable charges will be different
- By using the common variable charge to recover the necessary class revenue requirement, those Acquired Distributors with the above target service charges will “over-contribute” over the harmonization period until their service charge reaches the target level.

b. The impact range Tables 8, 9 and 10 of Exhibit G2 Tab 2 Schedule 1 have been re-stated based only on the target distribution bill inclusive of rate riders.

Table 8 with Proposed Distribution Rates

Range of impacts as a result of Harmonization of Residential Customers of Acquireds

Urban Residential			Residential R1		
# LDCs	# Cust	Impact Range %	# LDCs	# Cust	Impact Range %
2	6144	0 to 10	1	1025	<0
4	15193	10 to 20	5	4320	0 to 10
2	15141	20 to 30	1	469	10 to 20
1	8146	30 to 40	8	4636	20 to 30
1	3228	40 to 50	10	5323	30 to 40
1	7638	50 to 60	14	10177	40 to 50
0	0	60 to 70	12	14130	50 to 60
0	0	70 to 80	13	17442	60 to 70
1	5657	80 to 90	2	1845	70 to 80
			8	6372	80 to 90
			6	2982	90 to 100
			5	2226	100 to 135
			3	1735	135 to 170
12	61,147		88	72,682	

Table 9 with Proposed Distribution Rates

Range of impacts as a result of Harmonization of energy General Service customers of Acquireds

Urban GS			GSe		
# LDCs	# Cust	Impact Range %	# LDCs	# Cust	Impact Range %
3	1502	<0	2	207	10 to 30
1	294	0 to 10	15	1110	30 to 50
0	0	10 to 20	12	2543	50 to 70
3	1115	20 to 30	21	3997	70 to 90
1	934	30 to 40	10	979	90 to 110
1	1107	40 tp 50	9	1069	110 to 130
1	578	50 to 60	8	1222	130 to 150
0	0	60 to 70	3	118	150 to 170
1	713	70 to 90	7	918	170 to 190
			2	357	190 to 210
			0	0	210 to 230
			1	112	230 to 250
11	6,243		90	12,632	

Table 10 with 2008 Proposed Distribution Rates

Range of impacts as a result of Harmonization of demand General Service customers of Acquireds

Urban GS			**GSd**		
# LDCs	# Cust	Impact Range %	# LDCs	# Cust	Impact Range %
1	26	20 to 30	1	9	<10
1	40	30 to 40	8	52	10 to 20
1	85	40 to 50	5	16	20 to 30
0	0	50 to 60	3	24	30 to 40
2	131	60 to 70	10	313	40 to 60
0	0	70 to 80	10	113	60 to 80
3	176	80 to 90	19	214	80 to 100
3	197	90 to 130	8	123	100 to 120
			6	60	120 to 140
			6	90	140 to 160
			5	72	160 to 180
			3	52	180 to 200
			2	29	200 to 220
11	655		86	1,167	

c. The impact range analysis of Exhibit G2, Tab 2, Schedule 1, Tables 8, 9 and 10 has been augmented with the estimated total bill increase based on the average customer per rate class. The increase in average total bill was multiplied by total customers in Acquired Distributor to derive the estimated total bill increase

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Table 8 with estimated Total Bill Increases

Range of impacts as a result of Harmonization of Residential Customers of Acquireds

Urban Residential				Residential R1			
# LDCs	# Cust	Impact Range %	$ Increase	# LDCs	# Cust	Impact Range %	$ Increase
0	0	-5 to 0	-	2	2095	0 to 3	5,561
1	3618	0 to 2	6,654	3	2225	3 to 6	11,290
1	2526	2 to 4	6,641	4	2147	6 to 9	18,432
4	15193	4 to 6	89,305	14	8661	9 to 12	107,329
1	6347	6 to 8	48,866	14	9687	12 to 15	153,133
1	8794	8 to 10	81,688	20	22837	15 to 18	411,984
1	8146	10 to 12	91,880	13	14722	18 to 21	306,351
3	16523	12 to 18	251,537	10	6347	21 to 24	149,225
				4	1906	24 to 27	50,069
				2	1290	27 to 30	35,844
				2	765	30 to 33	22,941
12	61,147		576,571	88	72,682		1,272,159

Table 9 with estimated Total Bill Increases

Range of impacts as a result of Harmonization of energy General Service customers of Acquireds

Urban GS				GSe			
# LDCs	# Cust	Impact Range %	$ Increase	# LDCs	# Cust	Impact Range %	$ Increase
3	1502	-5 to 0	(3,953)	0	0	0 to 3	-
0	0	0 to 2	-	0	0	3 to 6	-
1	294	2 to 4	1,544	1	99	6 to 9	1,641
3	1115	4 to 6	12,751	8	586	9 to 12	15,345
1	934	6 to 8	12,499	8	632	12 to 15	20,542
1	1107	8 to 10	18,223	12	2543	15 to 18	90,943
1	578	10 to 12	11,555	16	2876	18 to 21	125,651
1	713	12 to 14	18,318	13	2025	21 to 24	95,989
				10	1056	24 to 27	57,561
				11	1395	27 to 30	80,897
				7	917	30 to 33	59,022
				4	503	33 to 37	34,127
11	6,243		70,937	90	12,632		581,716

Table 10 with estimated Total Bill Increases

Range of impacts as a result of Harmonization of demand General Service customers of Acquireds

Urban GS				GSd			
# LDCs	# Cust	Impact Range %	$ Increase	# LDCs	# Cust	Impact Range %	$ Increase
0	0	less than -5	-	3	16	less than 0	(1,399)
0	0	-5 to 0	-	10	49	0 to 3	2,426
1	26	0 to 2	1,828	10	157	3 to 6	32,909
1	40	2 to 4	5,570	11	292	6 to 9	85,148
1	85	4 to 6	15,915	27	326	9 o 12	144,221
2	131	6 to 8	38,280	15	174	12 to 15	96,569
3	176	8 to 10	61,642	10	153	15 to 18	97,946
3	197	10 to 12	85,687	0	0	18 to 21	-
0	0	12 to 14	-	0	0	21 to 24	-
11	655		208,921	86	1,167		457,820

d. The impacts listed in Tables 8, 9 and 10 of Exhibit G2 Tab 2 Schedule 1 are inclusive of the proposed new Total Loss Factors [TLFs] for the rate classes. Any change in TLF was factored into the analysis by constructing the existing bill using existing old TLF and constructing the new bill using the new proposed TLF.

e. An error in how the illustrative tables were set up and a desire to reduce the numerous tables resulted in the re-filed and updated tables.

School Energy Coalition (SEC) INTERROGATORY #14 List 2

Interrogatory

Ref: G2/3/1, Results of Density Review and Customer Classification

a. Pg. 1-3. Please confirm that approximately 39.2% of the Urban Residential Class comes from the Acquired LDCs, approximately 50.2% of the UGSe class comes from the Acquired LDCs, and approximately 47.6% of the UGSd class comes from the Acquired LDCs. Please advise whether it is reasonable to conclude that the Acquired LDCs, as a whole, are significantly more urban in nature than the Legacy service territory, taken as a whole.

b. Please provide a list of the communities within the Legacy service territory that qualify for the urban density threshold. Where partial municipal areas qualify, please describe the parts that qualify, and the parts that are excluded.

Response

a. Yes, the Acquired customers contribute 39.2%, 50.2% and 47.6% to the UR, UGe and UGd proposed rates classes by number of customers, respectively. Using the customer per kilometre metric as urban gauge, Legacy Retail is approximately 10 and the Acquired distributors in aggregate are 37. Using these results it would appear that the Acquired distributors as a whole are more urban than Legacy Retail but both have urban pockets of 3,000 customers with a density of 60 customers per kilometre.

b. Following is the list of communities within Hydro One's legacy service territory that qualify for urban density threshold.

Location/Community	Municipality	Ops Area
Courtice	Clartington	Bowmanville
Ancaster	Hamilton	Dundas
Keswick	Georgina	Newmarket
Kingston	Kingston	Kingston
Petawawa	Petawawa	Cobden
Orleans	Ottawa	Wincehster
Elliot Lake	Elliot Lake	Algoma
Kirkland Lake	Kirkland Lake	Kirkland Lake
Val Caron Val Therese Hanmer	Greater Sudbury	Sudbury
Timmins (townsite)	Timmins	Timmins

The urban density criteria calls for a contiguous area of density with 3,000 or more customers and at least 60 customers per kilometer of line. As shown in the list above, in most cases the entire municipality does not meet that criteria.

School Energy Coalition (SEC) INTERROGATORY #15 List 2

Interrogatory

Ref: General. This additional IR is being provided as a reference number for the Company's response containing the detailed calculation of the impacts of harmonization on schools in the Acquired LDC service territories. The input data has been provided under separate cover to the Company last week.

Response

The SEC provided Hydro One with a list of schools and associated Hydro One account numbers under separate cover from the IRs submitted on March 17, 2008. The SEC list included 567 school account entries, of which 536 matched the 10-digit format of Hydro One's account numbers, while the remaining 31 entries had unusable account information. Of the 536 usable accounts, Hydro One was able to match 500 accounts to the 2006 billing information in our customer accounts system (CSS).

The list of 500 accounts provided by SEC, and matched to our 2006 CSS billing information, included 321 Acquired school accounts and 179 Legacy school accounts.

Table 1 on the following page summarizes the results for the school accounts identified by SEC.

In the process of verifying the information provided by SEC against our CSS information, Hydro One found an additional 189 school accounts not identified by SEC. These 189 accounts included 9 Acquired utility and 180 Legacy customer accounts.

Table 2 on the following page summarizes the results for both the 500 school accounts provided by SEC and the additional 189 school accounts identified in CSS based on 2006 billing information.

Table 1. Summary of Impacts for All School Accounts Identified by SEC

			2007 to Proposed 2008 Rates						2007 to Proposed Target Rates					
			Weighted Average Impact on Distribution Portion of Bill			Weighted Average Impact on Total Bill			Weighted Average Impact on Distribution Portion of Bill			Weighted Average Impact on Total Bill		
Billing Type	Customer Type	Number of Accounts	Annual ($)	Monthly ($/Cust/mnth)	%	Annual ($)	Monthly ($/Cust/mnth)	%	Annual ($)	Monthly ($/Cust/mnth)	%	Annual ($)	Monthly ($/Cust/mnth)	%
Energy Billed	SEC Legacy	85	2,329	2	1.1%	(3,749)	(4)	-0.5%	(6,833)	(7)	-3.1%	(12,911)	(13)	-1.8%
	SEC Acquired	145	73,409	42	37.7%	73,527	42	7.5%	127,400	73	65.5%	127,518	73	12.9%
Demand Billed	SEC Legacy	94	(58,956)	(52)	-4.2%	(159,264)	(141)	-3.8%	(114,936)	(102)	-8.3%	(215,913)	(191)	-5.1%
	SEC Acquired	176	993,537	470	66.2%	634,855	301	7.4%	1,104,816	523	73.7%	746,134	353	8.7%
Total		500	1,010,318	168	30.6%	545,368	91	3.8%	1,110,447	185	33.6%	644,828	107	4.5%

Table 2. Summary of Impacts for All School Accounts Identified by SEC and Hydro One

			2007 to Proposed 2008 Rates						2007 to Proposed Target Rates					
			Weighted Average Impact on Distribution Portion of Bill			Weighted Average Impact on Total Bill			Weighted Average Impact on Distribution Portion of Bill			Weighted Average Impact on Total Bill		
Billing Type	Customer Type	Number of Accounts	Annual ($)	Monthly ($/Cust/mnth)	%	Annual ($)	Monthly ($/Cust/mnth)	%	Annual ($)	Monthly ($/Cust/mnth)	%	Annual ($)	Monthly ($/Cust/mnth)	%
Energy Billed	SEC Legacy	94	3,066	3	1.1%	(2,958)	(3)	-0.3%	(7,569)	(7)	-2.8%	(13,594)	(12)	-1.6%
	All Acquired	146	74,737	43	37.6%	74,848	43	7.5%	128,619	73	64.8%	128,730	73	12.9%
Demand Billed	SEC Legacy	265	(280,138)	(88)	-6.7%	(562,697)	(177)	-4.3%	(439,448)	(138)	-10.5%	(722,676)	(227)	-5.5%
	All Acquired	184	1,042,389	472	66.7%	665,503	301	7.5%	1,164,023	527	74.5%	787,137	356	8.9%
Total		689	840,054	102	13.5%	174,696	21	0.7%	845,625	102	13.6%	179,597	22	0.8%