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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

October 19, 2009

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

Dear Ms. Walli:

EB-2009-0096 – Hydro One Networks' 2010-2011 Distribution Rate Application – Hydro One Networks Responses to Interrogatory Questions

Please find attached an electronic copy of responses provided by Hydro One Networks to Interrogatory questions. Also provided is an index page to show the original intervenor question numbers and the equivalent tab and schedule numbers. Three (3) hard copies will be sent to the Board on the morning of October 20, 2009.

Hydro One would like to note, that as a result of an interrogatory we have reviewed our Capital Cost Allowance ("CCA") calculations arising from the recent Federal budget change and confirm that we incorrectly applied the budget change to CCA class 12 assets. The impact of this correction is to reduce Distribution Revenue Requirement by $10.2M in 2010 and $9.0M in 2011. There is also an impact on the Smart Meter funding adder as a result of this CCA change. Please see Exhibit H, Tab 3, Schedule 18 and Exhibit H, Tab 3, Schedule 36 for additional details on the CCA change as well as the Smart Meter funding adder. Hydro One Networks will reflect this updated information in our final rate order.

The consulting study on incorporating CDM impacts in the load forecast has been delayed. We are working with the consultant to expedite completion of the study and will file the study as soon as completed. The status of this study was requested in Exhibit H, Tab 1, Schedule 11.

The Interrogatories have been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

Hydro One Networks will post electronic copies of the interrogatory responses on the Hydro One Networks' website for public access.

Hard copies of the Interrogatories will be provided to Intervenors within the next few business days.

Sincerely,

ORIGINAL SIGNED BY ANDY PORAY FOR SUSAN FRANK

Susan Frank

Attach.

c. EB-2009-0096 Intervenors

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Intervenor Name	Question List	Question Number	Equivalent Tab and Schedule Number - All responses are Exhibit H			
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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
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OEB Staff	1	17	Tab	1	Schedule	17
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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
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OEB Staff	1	26	Tab	1	Schedule	26
OEB Staff	1	27	Tab	1	Schedule	27
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OEB Staff	1	51	Tab	1	Schedule	51
OEB Staff	1	52	Tab	1	Schedule	52
OEB Staff	1	53	Tab	1	Schedule	53
OEB Staff	1	54	Tab	1	Schedule	54
OEB Staff	1	55	Tab	1	Schedule	55
OEB Staff	1	56	Tab	1	Schedule	56
OEB Staff	1	57	Tab	1	Schedule	57
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OEB Staff	1	67	Tab	1	Schedule	67
OEB Staff	1	68	Tab	1	Schedule	68
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OEB Staff	1	70	Tab	1	Schedule	70
OEB Staff	1	71	Tab	1	Schedule	71
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
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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
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OEB Staff	1	124	Tab	1	Schedule	124
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OEB Staff	1	126	Tab	1	Schedule	126
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OEB Staff	1	128	Tab	1	Schedule	128
OEB Staff	1	129	Tab	1	Schedule	129
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OEB Staff	1	142	Tab	1	Schedule	142
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OEB Staff	1	144	Tab	1	Schedule	144
OEB Staff	1	145	Tab	1	Schedule	145
OEB Staff	1	146	Tab	1	Schedule	146
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OEB Staff	1	148	Tab	1	Schedule	148
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OEB Staff	2	4	Tab	1	Schedule	160
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OEB Staff	2	6	Tab	1	Schedule	162
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OEB Staff	2	13	Tab	1	Schedule	169
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GEC	1	3	Tab	2	Schedule	3
Energy Probe	1	1	Tab	3	Schedule	1
Energy Probe	1	2	Tab	3	Schedule	2
Energy Probe	1	3	Tab	3	Schedule	3
Energy Probe	1	4	Tab	3	Schedule	4
Energy Probe	1	5	Tab	3	Schedule	5
Energy Probe	1	6	Tab	3	Schedule	6
Energy Probe	1	7	Tab	3	Schedule	7
Energy Probe	1	8	Tab	3	Schedule	8
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Energy Probe	1	10	Tab	3	Schedule	10
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Energy Probe	1	12	Tab	3	Schedule	12
Energy Probe	1	13	Tab	3	Schedule	13
Energy Probe	1	14	Tab	3	Schedule	14
Energy Probe	1	15	Tab	3	Schedule	15
Energy Probe	1	16	Tab	3	Schedule	16
Energy Probe	1	17	Tab	3	Schedule	17
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Energy Probe	1	21	Tab	3	Schedule	21
Energy Probe	1	22	Tab	3	Schedule	22
Energy Probe	1	23	Tab	3	Schedule	23
Energy Probe	1	24	Tab	3	Schedule	24
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Energy Probe	1	39	Tab	3	Schedule	39
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Energy Probe	2	44	Tab	3	Schedule	44
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Energy Probe	2	49	Tab	3	Schedule	49
Energy Probe	2	50	Tab	3	Schedule	50
Energy Probe	2	51	Tab	3	Schedule	51
Energy Probe	2	52	Tab	3	Schedule	52
Energy Probe	2	53	Tab	3	Schedule	53
Energy Probe	2	54	Tab	3	Schedule	54
Energy Probe	2	55	Tab	3	Schedule	55

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Energy Probe	2	58	Tab	3	Schedule	58
Energy Probe	2	59	Tab	3	Schedule	59
Energy Probe	2	60	Tab	3	Schedule	60
Energy Probe	2	61	Tab	3	Schedule	61
Energy Probe	2	62	Tab	3	Schedule	62
Energy Probe	2	63	Tab	3	Schedule	63
Energy Probe	2	64	Tab	3	Schedule	64
Energy Probe	2	65	Tab	3	Schedule	65
Energy Probe	2	66	Tab	3	Schedule	66
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Energy Probe	2	68	Tab	3	Schedule	68
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Energy Probe	2	71	Tab	3	Schedule	71
Energy Probe	2	72	Tab	3	Schedule	72
Energy Probe	2	73	Tab	3	Schedule	73
Energy Probe	2	74	Tab	3	Schedule	74
Energy Probe	2	75	Tab	3	Schedule	75
Energy Probe	2	76	Tab	3	Schedule	76
Energy Probe	2	77	Tab	3	Schedule	77
Energy Probe	2	78	Tab	3	Schedule	78
Energy Probe	2	79	Tab	3	Schedule	79
Pollution Probe	1	1	Tab	4	Schedule	1
Pollution Probe	1	2	Tab	4	Schedule	2
Pollution Probe	1	3	Tab	4	Schedule	3
Pollution Probe	1	4	Tab	4	Schedule	4
Pollution Probe	1	5	Tab	4	Schedule	5
Pollution Probe	1	6	Tab	4	Schedule	6
Pollution Probe	1	7	Tab	4	Schedule	7
Pollution Probe	1	8	Tab	4	Schedule	8
Pollution Probe	1	9	Tab	4	Schedule	9
Pollution Probe	1	10	Tab	4	Schedule	10
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Pollution Probe	1	12	Tab	4	Schedule	12
Pollution Probe	1	13	Tab	4	Schedule	13
Pollution Probe	1	14	Tab	4	Schedule	14
Pollution Probe	1	15	Tab	4	Schedule	15
Pollution Probe	1	16	Tab	4	Schedule	16
Envirocentre	1	1	Tab	5	Schedule	1
Envirocentre	1	2	Tab	5	Schedule	2
Envirocentre	1	3	Tab	5	Schedule	3
Envirocentre	1	4	Tab	5	Schedule	4
Envirocentre	1	5	Tab	5	Schedule	5
Envirocentre	1	6	Tab	5	Schedule	6
Envirocentre	1	7	Tab	5	Schedule	7
Envirocentre	1	8	Tab	5	Schedule	8
Envirocentre	1	9	Tab	5	Schedule	9
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PWU	1	3	Tab	6	Schedule	3
PWU	1	4	Tab	6	Schedule	4
PWU	1	5	Tab	6	Schedule	5
PWU	1	6	Tab	6	Schedule	6
PWU	1	7	Tab	6	Schedule	7
PWU	1	8	Tab	6	Schedule	8
PWU	1	9	Tab	6	Schedule	9
PWU	1	11	Tab	6	Schedule	10
PWU	1	12	Tab	6	Schedule	11
VECC	1	1	Tab	7	Schedule	1
VECC	1	2	Tab	7	Schedule	2
VECC	1	3	Tab	7	Schedule	3
VECC	1	4	Tab	7	Schedule	4
VECC	1	5	Tab	7	Schedule	5
VECC	1	6	Tab	7	Schedule	6
VECC	1	7	Tab	7	Schedule	7
VECC	1	8	Tab	7	Schedule	8
VECC	1	9	Tab	7	Schedule	9
VECC	1	10	Tab	7	Schedule	10
VECC	1	11	Tab	7	Schedule	11
VECC	1	12	Tab	7	Schedule	12
VECC	1	13	Tab	7	Schedule	13
VECC	1	14	Tab	7	Schedule	14
VECC	1	15	Tab	7	Schedule	15
VECC	1	16	Tab	7	Schedule	16
VECC	1	17	Tab	7	Schedule	17
VECC	1	18	Tab	7	Schedule	18
VECC	1	19	Tab	7	Schedule	19
VECC	1	20	Tab	7	Schedule	20
VECC	1	21	Tab	7	Schedule	21
VECC	1	22	Tab	7	Schedule	22
VECC	1	23	Tab	7	Schedule	23
VECC	1	24a	Tab	7	Schedule	24
VECC	1	24b	Tab	7	Schedule	25
VECC	1	25	Tab	7	Schedule	26
VECC	1	26	Tab	7	Schedule	27
VECC	1	27	Tab	7	Schedule	28
VECC	1	28	Tab	7	Schedule	29
VECC	1	29	Tab	7	Schedule	30
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VECC	1	31	Tab	7	Schedule	32
VECC	1	32	Tab	7	Schedule	33
VECC	1	33	Tab	7	Schedule	34
VECC	1	34	Tab	7	Schedule	35
VECC	1	35	Tab	7	Schedule	36
VECC	1	36	Tab	7	Schedule	37
VECC	1	37	Tab	7	Schedule	38
VECC	1	38	Tab	7	Schedule	39
VECC	1	39	Tab	7	Schedule	40
VECC	1	40	Tab	7	Schedule	41
VECC	1	41	Tab	7	Schedule	42
VECC	1	42	Tab	7	Schedule	43
VECC	1	43	Tab	7	Schedule	44
VECC	1	44	Tab	7	Schedule	45
VECC	1	45	Tab	7	Schedule	46
VECC	1	46	Tab	7	Schedule	47
VECC	1	47	Tab	7	Schedule	48
VECC	1	48	Tab	7	Schedule	49
VECC	1	49	Tab	7	Schedule	50

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VECC	1	52	Tab	7	Schedule	53
VECC	1	53	Tab	7	Schedule	54
VECC	1	54	Tab	7	Schedule	55
VECC	1	55	Tab	7	Schedule	56
VECC	1	56	Tab	7	Schedule	57
VECC	1	57	Tab	7	Schedule	58
VECC	1	58	Tab	7	Schedule	59
VECC	1	59	Tab	7	Schedule	60
VECC	1	60	Tab	7	Schedule	61
VECC	1	61	Tab	7	Schedule	62
VECC	1	62	Tab	7	Schedule	63
VECC	1	63	Tab	7	Schedule	64
VECC	1	64	Tab	7	Schedule	65
VECC	1	65	Tab	7	Schedule	66
VECC	1	66	Tab	7	Schedule	67
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VECC	1	70	Tab	7	Schedule	71
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VECC	1	79	Tab	7	Schedule	80
VECC	1	80	Tab	7	Schedule	81
VECC	1	81	Tab	7	Schedule	82
VECC	1	82	Tab	7	Schedule	83
VECC	1	83	Tab	7	Schedule	84
VECC	1	84	Tab	7	Schedule	85
VECC	1	85	Tab	7	Schedule	86
VECC	1	86	Tab	7	Schedule	87
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VECC	1	88	Tab	7	Schedule	89
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VECC	1	91	Tab	7	Schedule	92
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VECC	1	93	Tab	7	Schedule	94
VECC	1	94	Tab	7	Schedule	95
VECC	1	95	Tab	7	Schedule	96
VECC	1	96	Tab	7	Schedule	97
VECC	1	97	Tab	7	Schedule	98
VECC	1	98	Tab	7	Schedule	99
VECC	1	99	Tab	7	Schedule	100
VECC	1	100	Tab	7	Schedule	101
VECC	1	101	Tab	7	Schedule	102
VECC	1	102	Tab	7	Schedule	103
VECC	1	103	Tab	7	Schedule	104
VECC	1	104	Tab	7	Schedule	105
VECC	1	105	Tab	7	Schedule	106
VECC	1	106	Tab	7	Schedule	107
VECC	1	107	Tab	7	Schedule	108
VECC	1	108	Tab	7	Schedule	109
VECC	1	109	Tab	7	Schedule	110
VECC	1	110	Tab	7	Schedule	111
VECC	1	111	Tab	7	Schedule	112
VECC	1	112	Tab	7	Schedule	113
VECC	1	113	Tab	7	Schedule	114
VECC	1	114	Tab	7	Schedule	115
VECC	1	115	Tab	7	Schedule	116
VECC	1	116	Tab	7	Schedule	117
VECC	1	117	Tab	7	Schedule	118
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VECC	1	119	Tab	7	Schedule	120
VECC	1	120	Tab	7	Schedule	121
VECC	1	121	Tab	7	Schedule	122

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Intervenor Name	**Question List**	**Question Number**	**Equivalent Tab and Schedule Number - All responses are Exhibit H**			
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Rogers Cable	1	2	Tab	8	Schedule	2
Rogers Cable	1	3	Tab	8	Schedule	3
CCC	1	1	Tab	9	Schedule	1
CCC	1	2	Tab	9	Schedule	2
CCC	1	3	Tab	9	Schedule	3
CCC	1	4	Tab	9	Schedule	4
CCC	1	5	Tab	9	Schedule	5
CCC	1	6	Tab	9	Schedule	6
CCC	1	7	Tab	9	Schedule	7
CCC	1	8	Tab	9	Schedule	8
CCC	1	9	Tab	9	Schedule	9
CCC	1	10	Tab	9	Schedule	10
CCC	1	11	Tab	9	Schedule	11
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Ontario Energy Board (Board Staff) INTERROGATORY #1 List 1

Interrogatory

Issue 1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

1. Ref: ExhG1/Tab4/Sch4/p4-5

The Board's Decision re EB-2007-0681 reads in part at p. 40:

> "…the Board strongly encourages Hydro One to proceed with the sale on the basis of the principles outlined. If that fails to occur within a time period for implementation before May 1, 2010, the Board directs Hydro One as part of its 2010 IRM to bring forward evidence relating to the construction of a rate specific to address Milton's circumstances."

Hydro One has brought forward evidence that some 30 customers would save $6.8 million if the charge determinant were line length, while seven customers would experience the corresponding increase.

a) Please describe actions taken by Hydro One since the 2008 Decision to effect the sale of the facilities in question to Milton Hydro.

b) Did Hydro One consider only the alternative of the Specific ST Line rate, i.e. $/km, or did it also consider other alternatives such as a rate per "kW times kilometers"? Please provide a brief explanation.

Response

a) Hydro One has met with Frank Lasowski (the new President and CEO of Milton Hydro) and is waiting for their response to the current offer.

b) Hydro One only considered a $/km alternative rate. Hydro One is still of the view that the current rate design is appropriate and simple to understand and administer. Therefore, Hydro One did not consider a "kW times kilometers" alternative. Any alternative rate design approach will have winners and losers and would not eliminate the fact that different revenues would be collected from the customers paying specific charges and the shortfall/surplus would need to be made up by other ST customers.

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

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

2. Ref: ExhA/Tab4/Sch1/p3
Hydro One submitted its five year vision and its associated strategic objectives for distribution activities in Table 1. These objectives relate to areas such as safety, environmental protection, customer satisfaction, reliability and productivity.

a) Please complete Table 1 with additional columns that: 1) cover the last five years of performance with respect to the performance indicators that reflect the proposed Hydro One goals/objectives; 2) state the performance levels that are being targeted that reflect the proposed Hydro One goals/objectives; 3) detail any gaps that must be closed to meet the desired target level [for example the increments necessary to achieve top quartile reliability or 90% customer satisfaction]; and 4) state the estimated time required to close these performance gaps.

b) Please provide the principal reasons why Hydro One believes it is not performing at the desired or end state level at the current time and what the significant differences are between Hydro One and the organizations achieving these benchmark levels.

c) Please explain; 1) why Hydro One believes it can close these performance gaps; 2) what specifically is Hydro One proposing to change in order to close these gaps; and 3) why have these changes not already occurred?

Response

a) See table on the following page for responses to points 1 to 4.

STRATEGIC OBJECTIVES	FIVE-YEAR VISION	Performance Measure/Indicator	Unit	04	05	06	07	08	Gap	Time to Close Gap
Injury-Free Workplace	Achieve zero lost-time injuries	Lost Time Injuries	# of lost time incidents per 200,000 hrs worked	0.4	0.5	0.6	0.3	0.3	0.3	5 yr
Satisfying Our Customers	90% Customer Satisfaction	Customer Satisfaction (Six Customer Segments)	% satisfied	76	81	81	86	86	4	5 yr
Continuous Innovation	Develop and meet Smart Grid goals	Fully Enabled Smart Meters	# of Smart Meter On stream	New measure developed for 2009						
Reliable, Distribution Systems	Achieve top-quartile distribution reliability (like with like)	Dx Duration of Customer Interruptions	Hrs per customer	6.4	7.7	7.0	8.2	8.2	To Q1 of Comparable Utility *	5 yr
Protecting the Environment	Reduce our environmental footprint through oil spill management and greenhouse gas reduction	Oil Spill	% recovered from oil-filled electrical equipment spills	Measure introduced in 2009						
		Greenhouse Gas Reduction	# Metric Tons of Greenhouse Gas Removed	New measure developed for 2009						
Recruitment Knowledge Transfer	Achieve and maintain top-quartile employee engagement	Employee Survey	Grand Mean	New measure developed for 2009						
Shareholder Value	Achieve the ROE allowed by the Ontario Energy Board and maintain "A" credit rating category	Net Income After Tax	$M	407	483	455	399	497	$ to move to ROE	NA
		Credit Rating	Long-Term Debt Rating Category	A	A	A	A	A	No gap	
Productivity	Achieve top-quartile unit costs in Distribution	Distribution Unit Cost – Capital and O&M Costs per km	$/km	4.2	4.7	5.5	5.8	6.2	To Q1 of Comparable Utility *	5 yr

* Hydro One cannot predict what the first quartile value will be in 5 years, therefore a numerical gap cannot be projected. However, Hydro One will be analyzing the various practices of the current first quartile utilities in terms of reliability and costs to identify best practices that will then be adopted, as appropriate, to enable Hydro One to become a first quartile utility.

b) The strategic objectives and five-year vision are the drivers of the Company's mandate. The targets set for its strategic objectives represent a striving for continuous improvement in those areas that represent the Company's core values of Safety, Stewardship, Excellence and Innovation. As an example, the safety target of zero lost time injuries was established to aggressively reduce injuries in the work place; this is an ongoing challenge to ensure that all employees work safely all of the time. In the case of its Shareholder Value strategic objective, the goal is to maintain the targeted level of performance.

Some of the performance measures tracked are specific to Hydro One and are not benchmarked. For those measures that can be benchmarked it should be recognized that the companies representing "top quartile" performance may change over time and not all companies can excel in all areas.

c) Hydro One believes that performance related to its Strategic Objectives can be further improved by executing the initiatives listed in Attachment 1. These changes have been identified as part of Hydro One's Strategic plan and are part of a continually evolving business environment to meet present and future challenges.

Creating an Injury-Free Workplace and Maintaining Public Safety

KEY SAFETY INITIATIVES:
• Build and improve on the existing safety culture.
• Maintain and enhance a healthy and robust Internal Responsibility System.
• Utilize the best knowledge and science for workplace improvement and risk reduction.
• Ensure employee development and competence at all levels in the Company, for new workers as well as seasoned veterans. Formal and informal learning and teaching will be cultivated, and leaders and champions developed.
• Ensure compliance with approved work procedures, rules and regulations.
• Ensure open, honest, two-way communication.
• Leverage the management system to drive continuous improvement and ensure all the needed programs, initiatives and activities are operationalized.
• Maintain high standards for public safety.

Satisfying Our Customers

KEY CUSTOMER INITIATIVES:
Large Customers
• Continue company-wide training in customer service skills and negotiation.
• Monitor commitments and improve processes.
• Continue our Executive Sponsorship program.
• Streamline transmission connection procedures.
• Improve online customer service.
• Build strong local relationships through station superintendents.
• Continue effective coordination of operations with large customers through the Ontario Grid Control Centre.

Mid-Customer Segment
• Make lines superintendents the single point of contact for our customers.
• Improve the process for connecting small generators.
• Focus our efforts on customers' needs for reliable supply.
• Communicate openly, clearly and often.

Residential Customers
• Improve call centre service standards.
• Increase our community presence.
• Improve communication of critical outage information via phone and web.

Corporate Reputation
• Build strong working relationships with local media.
• Build strong relationships with colleges and universities.
• Broaden our strategy to reach province-wide opinion leaders.

Focusing on Continuous Innovation to Ensure a Modern, Flexible and Smart Electricity Grid

KEY INNOVATION INITIATIVES:

Distributed Generation
• Invest proactively in distribution and transmission infrastructure to enable major additions of distributed generation.
• Improve our response times to new distributed generation connections, at all stages.

Research
• Expand research initiatives with Ontario universities to solve technical and engineering issues.
• Leverage productive research through organizations like the Ontario Centres of Excellence.
• Continue to utilize the technical expertise of Ontario research companies.

Development of the Smart Grid

• Improve reliability, reducing line losses and improving overall efficiency.
• Enable the efficient incorporation of distributed generation.
• Manage customer loads through time-of-use pricing and monitoring of demand.
• Give customers information and control over their electricity use.
• Provide real-time dispatch and control on the distribution system.

Building and Maintaining Reliable, Cost-Effective Transmission and Distribution Systems

KEY DISTRIBUTION INITIATIVES:
• Established an internal task force comprised of all lines of business to better enable us to incorporate renewable and distributed generation on our distribution system.
• Deliver initiatives that support government policies on distributed generation and conservation and demand management.
• Continue to seek efficiencies through productivity initiatives and through opportunities for rationalization of the distribution sector.

Protecting and Sustaining the Environment for Future Generations

KEY STRATEGIC INITIATIVES:
• Engage our employees and work with contractors/suppliers as catalysts to help us become a more energy-efficient and environmentally-conscious company.
• Implement energy efficiency and emission reduction initiatives in our fleet and facilities.
• Measure, monitor and report on our internal energy use and savings identified through our initiatives.
• Assess and expand our understanding of the linkages among key environmental issues, economic issues, and community issues.
• Implement a climate change strategy that identifies potential impacts of climate change on our business and proactively prepares for and addresses these impacts.

Developing Critical Skills and Knowledge Retention in the Face of Demographic Change

KEY STRATEGIC INITIATIVES:
• Promote a safe and healthy work environment.
• Attract and retain top talent for key positions.
• Integrate diversity principles into all human resources practices.
• Develop all staff with a focus on high potential employees.
• Implement skills and knowledge retention and transfer programs.
• Excel at managing performance.
• Secure employee commitment.
• Partner with educational institutions, First Nations and Métis to secure our future employee base.

Maintaining a Commercial Culture that Increases Value for our Shareholder

KEY STRATEGIC INITIATIVES:
• Achieve stable, consistent financial performance.
• Enhance productivity and cost effectiveness.
• Maintain a capital structure consistent with the funding requirements for a significantly increased work program.
• Maintain our dividends and payments in lieu of taxes.
• Ensure full transparent disclosure consistent with meeting public reporting requirements.
• Commit to achieving our financial targets.

Achieving Productivity Improvements and Cost-Effectiveness

KEY PRODUCTIVITY INITIATIVES:
• Balance strategic procurement of non-core services with internal measures to reduce the cost of core functions.
• Continue our efforts to manage costs through competitive tenders of large construction projects.
• Continue to drive productivity in core services.
• Develop clear and demonstrable evidence of productivity and cost reductions achieved.
• Ensure rigorous benchmarking to allow management and the Board of Directors to gauge progress in increasing productivity and managing costs.
• Replace core enterprise information technology that has reached its end-of-life; transform associated business processes and corporate culture; and allow us to manage commitments to achieve improved value, productivity and lower unit costs (the Cornerstone project).
• Automate distribution operations and enhance customer service through smart meter infrastructure and associated communications capability.

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

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Ref: ExhA/Tab13/Sch1/p4, parts (b) to (d)

a) In each of the cases from (b) to (d), where Hydro One has requested that the Board affirm a rate treatment consistent with the current CGAAP, please indicate what the accounting treatment would be and the dollar impact on costs and revenue requirement in each of 2010 and 2011 if the Board chooses not to accept this proposal.

b) For each of items (b) to (d) there is an implication in the paragraph on page 4 beginning at line 21 that Hydro One is requesting something from the Board, i.e., at line 24 it says "we are requesting a rate treatment for PP&E, intangible assets and depreciation consistent with current CGAAP for purposes of IFRS in 2011." It is not clear from the submission exactly what it is that Hydro One is requesting. Please clarify and explain why Hydro One considers it necessary for the Board to grant such request(s).

c) Given that Hydro One submitted its application prior to the IASB issuing its exposure draft on rate regulated accounting July 2009, and prior to the Board issuing its Report on Transition to IFRS on July 28, 2009, indicate what, if any, changes Hydro One would make to its submission in light of the fact that the exposure draft and the Board's Report are now issued.

d) Page 4, part (b) – Hydro One states that "under current IFRS, only directly attributable borrowing costs are capitalized and only upon qualifying assets." CGAAP as expressed in the CICA Handbook Section 3061.05 states that the cost of an item of property, plant and equipment includes "all costs directly attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use." Please indicate what Hydro One considers to be the difference between these two statements and indicate what the impact of adopting IFRS

would be on its capitalized carrying charges, its current period costs and revenue requirement in each of 2010 and 2011.

e) Page 4, part (c) – Does Hydro One's description in this section of accounting treatment pertain to gains and losses on disposal of all PP&E and intangible assets or only gains and losses on assets that are depreciated or amortized on a group basis? Please indicate how much gain and/or loss is included in the revenue requirement that pertains to disposal of assets in each of 2010 and 2011.

f) Page 4, part (d) – Please provide a description of the key terms and conditions that are contained in a typical agreement between Hydro One and a developer (or other provider of contributed capital) for contributions received for construction work. Describe the basis for Hydro One's choice of the accounting treatment as described in part (d) in relation to these terms and conditions. What is the proposed period of amortization? What is the method of amortization (e.g., straight line, annuity based). Does this differ from the amortization period or method currently assigned to such contributions? What is the impact of cost and the revenue requirement of any proposed change in treatment?

Response

a) The current application was prepared consistent with EB-2007-0681, considering the anticipated International Accounting Standards Board exposure draft on rate regulated accounting. As noted in Exhibit A, Tab 13, Schedule 1, Page 4, lines 22-26, Hydro One Distribution did not expect nor incorporate any adjustments to PP&E, intangible assets and depreciation as a result of a change to IFRS. Hydro One's independent depreciation consultant, Foster Associates Inc., is in the initial stages of determining appropriate straight-line deprecation rates to be applied in future under an IFRS environment.

If the Board chose not to accept this proposal, then the costs associated with PP&E and intangibles would be higher (less would be capitalized). In addition, losses on premature retirements and any higher depreciation from IFRS compliant methodologies would further lead to higher costs. Consistent with the guidance in the Board's Report (EB-2008-0408, p.41, second bullet) Hydro One will track such premature retirement gains and losses. In total, all the adjustments would lead to a higher revenue requirement being proposed. As Hydro One Distribution costed its work projects and programs consistent with past applications, no amounts were computed under the above scenario.

b) As noted in a) above, Hydro One has based its application on costing of work projects and programs consistent with past applications. Given the anticipated IASB exposure

draft on rate regulated accounting at that time, the rate treatments for PP & E, intangibles and depreciation were considered compatible under current CGAAP and IFRS. Therefore, no change in treatment was proposed.

c) No changes are considered necessary given that Hydro One Networks anticipated the results of both the exposure draft and the Board's Report on Transition to IFRS.

d) The difference between the two statements is that under IFRS only qualifying assets, those that necessarily take a substantial period of time to get ready for their intended use, should attract interest. On this basis, it is possible that not all capital assets will be qualifying assets, and therefore, some capital expenditures under IFRS may not attract interest. We are not able to quantify the impact on our current period costs and revenue requirement as we are still assessing what constitutes a "substantial period of time." However, given the long-term nature of much of our capital programs and projects Hydro One anticipates that a significant portion of our capital expenditures will continue to attract interest.

e) Hydro One's description in this section applies to gains and losses on disposal of all PP&E and intangible assets under IFRS. Note that group depreciation is not allowable under IFRS. No such gain or loss is included in the revenue requirement for either 2010 or 2011. Consistent with the Report of the Board "Transition to International Reporting Standards" (EB-2008-0408, p. 41, 2nd bullet), Hydro One Distribution will identify such gains and losses, and report them as in past rate application filings.

f) Hydro One has two main categories of agreement that results in a capital contribution - connection and load agreements. Connection agreements require that customers contribute amounts to reimburse actual connection costs while contributions to be made under load agreements are determined using various factors including: the customer's risk classification; total project cost; estimated incremental revenue from the customer's forecasted new load; and non-pooled costs that are related to the project.

Under IFRS, Hydro One expects that most contributed capital amounts will be recorded as long-term unearned revenue (i.e. a liability) and be amortized to revenue on a straight-line basis over the related assets' depreciation service lives. Such contributions are currently netted with PP&E and therefore offset straight-line depreciation expense in the revenue requirement and reduce carrying value in rate base.

While this expected IFRS treatment will change the balance sheet geography of most of these contributions from a PP&E offset to a liability, the treatment but would not change the existing revenue requirement. There is a potential exception for contributions (e.g. generator connections) where there is no expectation of an ongoing

customer relationship. Such contributions are expected to be required to be recorded as revenue as received under IFRS.

Hydro One is still finalizing its assessment of the IFRS accounting rules on all of its existing types of customer contributions.

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

Interrogatory

Issue 1.3 Is service quality, based on the OEB specified performance indicators, acceptable?

4. Ref: ExhA/Tab4/Sch1/p18 & 19 and ExhC1/Tab2/Sch1/p2, Table 1
Previous Hydro One proceeding EB-2007-0681; Response to Board Staff IR #14; 2008 Vegetation Management Program Review Report, pages 14 and 18

Hydro One states that its interruption frequency (w/o Force Majeure events) has been increasing since 2005. In addition, at page 19 it is indicated that tree contacts are the greatest contributor to its interruption frequency.

a) Given that tree contact is a significant cause of outages for Hydro One and given that its Right of Way ("ROW") clearing cycle time is among the longest for the utility industry (and this is a contributor to tree related outages), why has Hydro One taken until 2009 to start to address its ROW clearing cycle.

b) Since it will likely take some time for the reduced ROW clearing cycle time to have an affect on interruption frequencies, is Hydro One taking other measures to reduce the frequency of interruptions on its distribution system and if so, what are these measures and what is the projected affect that they will have and if Hydro One is not planning to carry out any other measures, why is it not?

Response

a) Hydro One Distribution's actions to reduce the clearing cycle began well before 2009. The need to reduce the clearing cycle was raised in Hydro One's 2006 Distribution Rates Application (Exhibit C1, Tab 2, Schedule 2 of EB-2005-0378) and again in its 2008 Distribution Rates Application (Exhibit C1, Tab 2, Schedule 2 of EB-2007-0681). Hydro One Distribution has noticeably increased Line Clearing accomplishments beginning in 2007 as noted in Exhibit H, Tab 1, Schedule 34.

b) As vegetation is the most frequent cause of interruptions, reducing the clearing cycle is one of the primary measures that Hydro One Distribution is taking to improve reliability. Other measures that are being, or have been, undertaken and are expected to have a more immediate impact include:

- Increasing the expenditures on Lines Projects as discussed on page 20 of Exhibit D1, Tab 3, Schedule 2 and in particular on Large Sustainment Projects. This increase not only addresses end-of-life issues but also targets local improvements

to feeder reliability performance by rebuilding off-road lines to on-road locations. Examples of these projects are found in Exhibit D2, Tab 2, Schedule 3.

- Continued focus on reliability improvements through Capability Reinforcement Projects as discussed on pages 7-9 of Exhibit D1, Tab 3, Schedule 3. Expenditures in this area are increasing to address loading issues and Hydro One Distribution is taking advantage of many of these projects to improve supply reliability through new facilities and feeder re-configurations. Examples of these projects are found in Exhibit D2, Tab 2, Schedule 3.

- Increasing the number of defect corrections on the system as detailed on page 20 of Exhibit C1, Tab 2, Schedule 2. As noted in the response to interrogatory Exhibit H, Tab 1, Schedule 21, defect corrections are predominantly undertaken to address safety and end-of-life concerns but they do impact on reliability given that equipment caused interruptions accounted for 22% of SAIDI and 27% of SAIFI in recent years as shown at Exhibit A, Tab 4, Schedule 1, pages 19-20.

- A Subtransmission Feeder Sectionalizing Project focused on improving reliability was approved as part of Hydro One's 2008 Rates Application (EB-2007-0681) and was successfully completed. A longer term initiative related to sectionalizing and control of feeders is Hydro One Distribution's Smart Grid Project, which is detailed in Exhibit D2, Tab 2, Schedule 3, Reference D35. This project is expected to bring enhanced monitoring, proactive response capability, and control to the distribution system that will improve reliability performance in the long term.

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

Interrogatory

Issue 1.3 Is service quality, based on the OEB specified performance indicators, acceptable?

Ref: ExhA/Tab15/Sch1/p1,6,7

Hydro One states that "Hydro One deems a Force Majeure to have occurred when 10 % or more of its customers have been interrupted by an event".

a) Is this 10% - Force Majeure protocol a standard in the electric utility industry and is it in wide usage by a number of utilities and if it is in use, list the other utilities that have employed this methodology.

b) If this protocol is not in wide usage, why is Hydro One utilizing this approach?

Response

a) There is no industry standard however the 10% criterion is used by a number of utilities and commissions.

They include:

Pacificorp
Wisconsin Public Service Commission
Pennsylvania Public Service Commission
California Public Service Commission
Oklahoma Corporate commission
State of Iowa /Department of Commerce Utilities Board
(MidAmerican Energy, North East Missouri Electric Power Co-operative, Interstate Power and Light company)
Public Utility Commission of Texas

b) Hydro One has used the 10% criterion for defining Force Majeure events in both its 2006 cost of service Distribution Application (EB-2005-0378) and its 2008 Distribution Application (EB-2007-0681). In the absence of an industry standard, Hydro One believes the criterion of 10% customers interrupted by a major event to be reasonable based on the following points;

1) The value of 10% captures major events that result in significant physical damage to the system and impact on our customers.
2) Other comparable jurisdictions are using it.
3) It defines events that are outside the “day to day” operations of the utility, with these events varying from year to year based on the external impacts to the distribution system

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

Interrogatory

Issue 1.4 Is Hydro One's proposal to change the effective date for implementation of its proposed distribution rates to January 1, 2010 rather than the conventional May 1st effective date appropriate and has Hydro One appropriately addressed the revenue consequences of proposed change?

6. Ref: ExhA/Tab2/Sch1

What are the reasons for Hydro One's decision to change the effective date of the rate change from May 1 to January 1? Under this proposal, how will Hydro One address the concern that ratepayers will now see three rate changes each year [January 1, May 1(RPP), and November 1, (RPP)]?

Response

The earlier rate implementation date will facilitate the incorporation of the new Hydro One Sub- Transmission (ST) rates by other LDCs into their own rates that would usually take effect on May 1, 2010.

This topic was discussed at a Hydro One EB-2009-0096 Stakeholder session on May 25, 2009 (Reference Exhibit A, Tab 17, Schedule 1, Appendix C page 2).

The multiple rate changes will be addressed through clear and timely customer communications

Ontario Energy Board (Board Staff) INTERROGATORY #7 List 1

Interrogatory

Issue 1.4 Is Hydro One's proposal to change the effective date for implementation of its proposed distribution rates to January 1, 2010 rather than the conventional May 1st effective date appropriate and has Hydro One appropriately addressed the revenue consequences of proposed change?

Ref: ExhA/Tab2/Sch1
Please provide a calculation of the revenue increase Hydro One will experience as a result of the higher rates proposed in this application becoming effective 4 months earlier and displacing the previously approved rates. Please include all relevant assumptions and explanations.

Response

The revenue increase Hydro One will experience as a result of higher rates proposed in this application becoming effective 4 months earlier is approximately $44.3M.

Description	**2010**	reference
2010 Rates Revenue Requirement	1,101.4	a *
Less: Revenues at 2009 rates	981.8	b
Full Year Revenue Increase	119.6	c = a - b
Forecasted Load Jan to Apr	37%	d
Revenue Impact	44.3	e = c x d

* Exhibit E1, Tab 1, Schedule 1, Attachment 1

The monthly forecasted load was used to determine the proportion of the load that is expected from January to April of 2010. Please refer to Exhibit H, Tab 7, Schedule 1, part C.

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

Interrogatory

Issue 1.5 Is the overall increase in 2010 and 2011 revenue requirement reasonable given the impact on consumers?

8. Ref: Comment Letters received by the Board in response to the Notice of Application
The Board has received over 130 letters of comment in response to the Notice of Application. Virtually all letters protested the delivery charge bill increase of 9.5% for 2010 and 13.3% in 2011. Board staff has summarized a number of the concerns raised. Please provide Hydro One's response to the following concerns expressed in these letters:

a) The requested increase is too high and rates should be decreased or frozen. Why is such a large increase required, when inflation is very low?

b) Hydro One salaries are too high, there are too many Hydro One employees on the $100,000+ salary disclosure list and salaries should be reduced.

c) Higher electricity delivery rates are the last thing that the economy needs. Has Hydro One considered the impact on Northern communities as resource based industries shut down and workers are laid off?

d) Has Hydro One considered the impact of this increase on pensioners, those on fixed incomes and the working poor?

e) What steps has Hydro One taken to reduce costs?

f) Consumers have concerns about the high fixed charge portion of their bill, as they are paying high bills with very little consumption.

Response for part A through F

Hydro One's approach to the letters of comment is provided in Exhibit H, Tab 1, Schedule 9.

Hydro One is very aware of the current economic downturn and the corresponding impact on the province and its own Distribution Customers. Hydro One believes that all ratepayers deserve fair, reasonable and affordable rates and is committed to ensuring our rates are an accurate and fair reflection of our costs.

Customer concerns and impacts were taken into account at many points in the process of developing this application and Hydro One remains committed to improving our Customers satisfaction. (Reference Exhibit A, Tab 14, Schedule 1 and Exhibit A, Tab 14, Schedule 6: the Planning Process and the Investment Prioritization Process respectively)

Hydro One's application centres on work that is essential to continue reliably serving its customers as well as support the Government's energy policy directives. As discussed in Exhibit A, Tab 16, Schedule 1 (Cost Efficiencies / Productivity), Hydro One continues to take steps to ensure its operations are working as effectively, efficiently and productively as possible. In addition, Hydro One is continuing its efforts to reduce labour costs as detailed in Exhibit C1, Tab 3, Schedule 2 (Compensation, Wages and Benefits).

The impacts on customers' bills are calculated in accordance with OEB guidelines which set the maximum allowable annual bill increase, and require utilities to implement mitigating measures if bill increases are above that threshold.

Further, as discussed in Exhibit H, Tab 6, Schedule 2, Hydro One's understanding is that the Ministry of Energy and Infrastructure is in the process of planning to implement a province-wide integrated program for low-income energy consumers as they move forward with the GEGE Act.

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

Interrogatory

Issue 1.5 Is the overall increase in 2010 and 2011 revenue requirement reasonable given the impact on consumers?

Ref: Comment Letters received by the Board in response to the Notice of Application

As indicated above, the Board has received over 130 letters of comment from Hydro One customers regarding the impacts of this application. How many additional letters or customer contacts has Hydro One received with regard to this application? How has Hydro One responded to these customer concerns?

Response

To date Hydro One has received 145 comment letters (via the OEB) on the current Distribution Rate Application, 2 of which are additional letters directly received by Hydro One that were not also copied to the OEB. Given that many of these comments came in via e-mail we cannot confirm that all are from H1 customers.

We do not have complete records on calls to our Customer Call Center. We can note that the Distribution 2009 rate change was implemented starting June 2009. Given that H1 DX has a 3 month billing cycle customers would see the rate increase bill insert and changes on their bills from June to August. We tracked rate question calls in August, and there were approximately 500, and we estimate only a minimal number of these were related to the 2010 rate application notice

Hydro One has responded to each letter or e-mail received. In most cases we outline, at a high level, how the hearing process works and how an individual may participate. This standard letter is shown below. In cases where specific rate impact information was requested we provided that information.

Hydro One Response Letter

> "I am writing to acknowledge Hydro One Networks receipt of your 'Date xx, 2009' email addressed to the Secretary of the Ontario Energy Board with comments on Hydro One Networks' 2010-2011 distribution rates application.
>
> Hydro One Networks has followed the Ontario Energy Board's guidelines for Ontario electricity distribution utilities with respect to preparing and filing cost of service rates applications. The Board's written hearing process which was outlined in the Notice published in newspapers does

provide you with opportunities to present your concerns and comments to the Board through your email of comment. The Board's Notice states that any comments filed on this Application will be "provided to Board members deciding the application" so you can be assured that your views will be part of the Board's deliberations in deciding this Application.

If you need more information, you can visit the Board's website at www.oeb.gov.on.ca or call the Board's Consumer Relations Centre at 1-877-632-2727 to obtain more information on the review process and ways to participate."

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

Interrogatory

Issue 1.5 Is the overall increase in 2010 and 2011 revenue requirement reasonable given the impact on consumers?

Ref: n/a
The Hydro One Networks website features a program for communities called "Powerplay" which provides grants to support and enhance children's sports and recreation facilities in Ontario communities served by Hydro One.
What were the expenditures of this program in 2008 and 2009 (projected) and how is the program funded? Are these expenditures included in Hydro One's revenue requirement?

Response

There are no expenditures associated with the Powerplay program included in Hydro One Distributions' revenue requirement.

The Powerplay program is funded by Hydro One Inc. and costs are not allocated to Distribution. Hydro One Inc.'s expenditures on the Powerplay program for 2008 were $0.8M and 2009 projected expenditures are $1.0M.

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

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

11. Ref: ExhA/Tab14/Sch 4/p4
The evidence indicates that the CDM related consulting study will be available by the end of September 2009. Does Hydro One have an update of the timing of this study? Will it still be filed by September 30, 2009?

Response

The consulting study on incorporating CDM impacts in the load forecast has been delayed. We are working with the consultant to expedite completion of the study. Hydro One will file the study as soon as completed and will keep the OEB informed on the progress of the study.

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

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

12. Ref: ExhA/Tab14/Sch 4/p5

Hydro One indicates that its load forecast is based on economic information and forecasts that were available in April 2009 and some, such as CPI, are based on a December 2008 forecast. Please provide an update table that shows the main forecast inputs as they were in April and how those inputs have changed up to September 2009 for both 2010 and 2011. Please include the major economic indicators such as Ontario GDP, US exchange rate, CPI, interest rates, housing starts, commercial and industrial production, etc. Will Hydro One file an updated forecast for this proceeding? If not, why not?

Response

The updated economic information is provided below.

Major Economic Indicators

Forecast Year	Ontario GDP (2002 M$)	Ontario CPI (2002=1)	Industrial GDP (2002 M$)	Commercial GDP (2002 M$)	Exchange Rate (US cents per C$)	Housing Starts (000's)	3-Month T-Bill Rate (%)	Long-Term Bond Rate (%)
Information used in April 2009 forecast								
2009	520,884	1.139	81,189	391,414	81.4	56.4	0.7	3.4
2010	532,864	1.163	84,058	399,392	88.2	58.3	1.1	3.7
2011	551,781	1.188	88,053	412,594	94.3	63.0	2.3	4.9
Updated information (September 2009)								
2009	514,038	1.143	75,160	390,845	86.0	49.5	0.4	4.1
2010	525,295	1.163	79,053	398,967	87.6	56.5	0.7	4.3
2011	544,863	1.185	84,017	412,087	91.2	66.8	2.4	4.6
Updated Information in September 2009 vs. Information used in April 2009 Forecast								
	(% Change)	(% Change)	(% Change)	(% Change)	(% Change)	(% Change)	(Change)	(Change)
2009	-1.3	0.3	-7.4	-0.1	5.6	-12.2	0.4	0.8
2010	-1.4	0.0	-6.0	-0.1	-0.7	-3.1	-0.3	0.6
2011	-1.3	-0.2	-4.6	-0.1	-3.3	5.9	0.1	-0.4

Note: Updated information for Ontario GDP and housing starts are based on consensus forecast prepared in Sept. 2009; Exchange rate forecast is based on IHS Global Insight released in September 2009; the rest is based on forecast released by IHS Global Insight in June 2009.

Hydro One is not planning on updating the load forecast 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.

The forecast is currently tracking well. Using consistent information as presented in Table 1 on page 2 of Exhibit A, Tab 14, Schedule 4, Hydro One Retail purchases are 0.1% above forecast on weather corrected basis with preliminary data as of early October 2009, and Hydro One Distribution's load forecast (i.e. including embedded distribution utilities and embedded industrial customers with more than 5 MW) is 0.3% below forecast on weather corrected basis.

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

Interrogatory

Issue 2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

13. Ref: ExhA/Tab14/Sch 4/p1
Hydro One indicates that its load forecast methodology has been reviewed and approved by the Board in many previous rate proceedings. Has Hydro One made any changes to the methodology that was reviewed in the EB-2007-0681 case or the EB-2008-0272 case? Please provide a listing of changes, why changes were made and the impact of the changes on specific aspects of the forecast.

Response

The load forecasting methodology used in this rate application is the same as EB-2007-0681 and EB-2008-0272.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

14. Ref: ExhC1/Tab2/Sch 1/p2

At Table 1 which summarizes the total OM&A Budget for the test years, Hydro One shows a budget of $591 million in 2010 and $606.2 million in 2011. For 2010, this is an increase of 27% over the Board approved 2008 level of $466 million. Please provide a scenario of the Hydro One OM&A budget where 2010 test year levels are held to $494 million (this assumes a 3% inflationary crease in 2009 and 2010). If held to such a budget, what OM&A budget categories would be cut, by how much and what would the consequences be for the Hydro One OM&A work program?

Response

Table 1 of Exhibit C1, Tab 2, Schedule 1 was revised as part of the update to the pre-filed evidence submitted on September 25th, 2009. The total OM&A budget is $560.0 million in 2010 and $575.2 million in 2011. For 2010, this is an increase of 20% over the Board approved 2008 level.

The budget proposed for the test years is based on the investment planning and prioritization process described in Exhibit A, Tab 14, Schedules 5 and 6. Application of the planning and prioritization process results in a set of investments that effectively balance our asset needs with due consideration for resource availability and the mitigation of risk to Hydro One's business values. Hydro One considers the proposed OM&A test year expenditures to be prudent and does not recommend a reduction in the budget.

If the test year OM&A budget was reduced, the risk to Hydro One's business values would increase. Hydro One would need to re-apply the prioritization process to identify which work programs could be cut to minimize the increase to the Company's risk. Hydro One anticipates that a reduction in the proposed budget of the magnitude suggested would impact legislated expenditures and the investments required to address customer needs, safety and reliability (e.g. Vegetation Management, PCB Programs, Smart Grid expenditures).

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch1/p2

a) Please provide in table format, total OM&A per customer for each year from 2004 to 2011. Please calculate the year-to-year variances and identify the drivers for the increases or decreases.

b) Please also provide in a table format, total OM&A per circuit km of distribution lines for each year from 2004 to 2011. Please calculate the year-to-year variances and identify the drivers for the increases or decreases.

Response

a) and b)

	2004 Actual	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009* Bridge	2010* Test	2011* Test
Total OM&A ($M)	346.0	362.1	399.3	486.4	471.3	527.1	560.0	575.2
OM&A Per Customer ($)	302.1	312.8	341.1	411.0	394.9	436.9	459.5	467.3
Variances per customer	-	3.5%	9.1%	20.5%	-3.9%	10.6%	5.2%	1.7%
OM&A Per Circuit km ($)	2531.3	2614.8	2846.0	3418.7	3276.5	3616.9	3794.9	3849.8
Variances per circuit km	-	3.3%	8.8%	20.1%	-4.2%	10.4%	4.9%	1.4%

* The 2009-2011 numbers of customers and circuit km are based on forecast values.

Costs to the end of 2007, including year-over-year variances were reviewed and approved as part of Hydro One Distribution 2006 and 2008 Cost of Service Applications.

The reasons for the increase in OM&A costs for 2010 and 2011 are detailed in the schedules associated with Exhibit C1, Tab 2 of the prefiled evidence and are summarized on page 2 of Exhibit C1, Tab 2, Schedule 1.

2007 to 2008

The reduction in 2008 over 2007 amounts is primarily related to a one-time pension adjustment as discussed in Exhibit C1, Tab 2, Schedule 7.

2008 to 2009

The increase in 2009 over 2008 amounts is primarily related to the following:

- An increase in a number of Shared Services cost components, as discussed in Exhibit C1, Tab 2, Schedule 6
- An increase in "Customer Care" OM&A due primarily to changes to scope or implementation timing for Regulatory or Service enhancement projects, an increase in bad debt and third-party contracts costs, and additional investment added to Customer Care for servicing new renewable distributed generation customers as of June, 2009.
- An increase in Vegetation Management to continue to transition towards a shorter maintenance cycle and to better manage reliability and unit costs.
- Modest increases in various sustainment and development programs.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch 2/p5

The costs for Stations Demand and Corrective Maintenance show a 20% reduction in the BridgeYear, yet the 2010 test year budget indicates a 21% increase back up to 2008 levels. Why is the cost reduction experienced in 2009 not carried forward to the test years? The evidence references fewer failures due to increases in preventative maintenance. Why does Hydro One expect a higher level of failures in the test years if preventative maintenance is showing positive results?

Response

The 2010 and 2011 projections are aligned with actual expenditures during 2006, 2007 and 2008. The 2009 projection for Stations Demand and Corrective Maintenance was determined to be inadequate for 2010 and 2011 based on recent diagnostic and inspection findings that are identifying a larger number of problems than anticipated for the 2009 budget. Hydro One does not expect a higher level of failures in the test years, however, the cost to address the identified deficiencies exceeds the benefit from the reduction in the number of transformer failures. As well, the 2009 projection anticipated a reduction in copper theft from our facilities which has not materialized, and will continue to demand expenditures in the test years.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch 2/p7

The costs for Planned Station Maintenance show a 29% increase in the 2010 test year budget and a further 12% increase in 2011. In relation to the previous question, why do these high increases in spending on stations not result in reductions in the Demand and Corrective Maintenance costs?

Response

The increases in the 2010 and 2011 Planned Station Maintenance costs are attributed to the incremental costs associated with testing and retro-filling equipment in response to new PCB Regulations. These expenditures are not expected to impact the Demand and Corrective Maintenance programs.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

18. Ref: ExhC1/Tab2/Sch 2/p13

Why do the forecast costs under the trouble calls category increase from 2009 Bridge year levels for the two test years? Has the impact of the increased spending on vegetation management been reflected in these forecasts? If so, to what extent and with what impact?

Response

Hydro One Distribution forecasts Trouble Call expenditures based on a 4-year weighted average methodology. The expenditures are divided into two categories: 1) Trouble Calls under non-storm conditions and 2) an Allowance for Storm Related costs. The 2009 level was forecasted based on 2004 to 2007 data, whereas 2010 and 2011 levels were forecasted based on 2005 to 2008 data. The allowance for trouble calls under non-storm conditions did not increase. The allowance for storm related costs increased from $6.0 million in 2009 to $8.0 million in 2010 in recognition of the increased storm activity experienced in 2008. The calculation of storm-related Trouble Call costs is provided in Exhibit H, Tab 1, Schedule 20.

The impact of increased spending on vegetation management is not expected to have an appreciable impact on Trouble Call costs in the 2010 and 2011 period for the reasons detailed in Exhibit H, Tab 1, Schedule 35.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

19. Ref: ExhC1/Tab2/Sch 2/p13

The evidence provides a reference to the trouble calls responded to annually. Please provide a record of trouble call volumes from 2004 to 2009. Please delineate the trouble calls into meaningful categories such as those that cause a service disruption, those that pose a high risk to the reliability of supply of safety, etc.

Response

The following table is a summary of the trouble call volumes from 2004 to 2009.

Year	Trouble Call Units
2004	46,767
2005	49,935
2006	49,697
2007	49,384
2008	50,149
2009 Forecast	49,500

Hydro One Distribution does not manage Trouble Call volumes at a more granular level.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

20. Ref: ExhC1/Tab2/Sch 2/p13

The evidence references an "allowance for storm related costs that are not capitalized" and is forecast to be $8 million in 2010 and $8.3 million in 2011. Please provide a detailed explanation/description of this allowance, how it is determined and what factors are used to determine the value of the allowance.

Response

A 4-year weighted average of historical spending is used to determine the value of the allowance for storm related costs that are not capitalized. For the 2010 and 2011 plan, this allowance was determined using 2005 to 2008 historical expenditures. The table below shows the calculation of the $8.0 million budget for 2010. The 2011 figure was escalated to $8.3 million.

Year	2005	2006*	2007	2008*
Actual Expenditures (millions)	$8.1	$21.0	$5.4	$12.7
Escalated** Expenditures Used for Forecast (2010 $)	$9.4	$9.1	$5.9	$8.6
Weighting	10%	20%	30%	40%
Weighted Average = $8.0 (i.e. 2010 Forecast)				

*For abnormally active storms years (i.e. 2006 and 2008), the values used for forecasting were set to the maximum of the other years.

**Escalation was calculated at 3% per annum.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch 2/p20-21

The evidence shows an increase in the number of "defects" to be addressed for the 2011 test year to 25,000, contributing to a 32% increase in Preventative and Corrective Maintenance costs in 2011. Hydro One indicates that this is due to the fact that a number of defects have been allowed to remain on the system in the past. Hydro One also states that not addressing these defects will increase future outages and increase safety risks. Please provide information that shows that the delay in addressing defects has indeed increased outages and therefore justifying the increased spending in 2011.

Response

Correcting known defects is a requirement of the Distribution System Code and the defect correction program proposed in this Application addresses this requirement.

Defect corrections are undertaken for a variety of reasons, one of which is managing the risk of outages. Other reasons include addressing end-of-life conditions and mitigating safety risks. During the period that Hydro One Distribution has been funding its Data Collection effort, the company has been deferring large numbers of defect corrections and has allowed certain defects to remain on the system. To manage the risks of this approach, Hydro One Distribution has been prioritizing defects such that those posing the greatest safety and reliability risks are addressed expeditiously, while lower risk defects are allowed to remain. Large numbers of defects have been deferred since as far back as 2005, and while Hydro One Distribution's approach to defects has not, to date, resulted in an increase to equipment caused outage levels, the Company does not believe this situation cannot be sustained indefinitely.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

22. Ref: ExhC1/Tab2/Sch 2/p21

Sentinel Lights: Has Hydro One taken active steps to reduce the number of Sentinel Lights for which it provides maintenance services? Has Hydro One considered any strategy to exit the Sentinel Light business in its current form?

Response

As discussed in Section 3.1 of Exhibit A, Tab 6, Schedule 1 and noted on page 21 of Exhibit C1, Tab 2, Schedule 2, Hydro One Distribution has a regulatory and contractual obligation to honour commitments made in relation to existing sentinel light installations. As a result, the company is required to respond to maintenance requests and the needs of existing installations.

Hydro One Distribution is no longer accepting requests for new installations and is retiring existing installations when opportunities arise.

Ontario Energy Board (Board Staff) INTERROGATORY #23 List 1

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

23. Ref: ExhC1/Tab2/Sch 2/p23

Hydro One is increasing the expenditures for PCB Lines Equipment Inspection and Waste Management significantly by 54%, 65% and 60 respectively in 2009, 2010 and 2011. This increased expenditure is justified to meet an Environment Canada regulation with a target 16 years from now (2025). Has Hydro One considered postponing or delaying the increase in inspections and waste management to later years? Will natural equipment replacement efforts, as assets wear out, not reduce the inventory of PCB contaminated equipment in any case?

Response

Yes, Hydro One Distribution has considered postponing expenditures in 2010 and 2011 and has determined that the benefits of proceeding with the work outweigh the advantages of postponing it.

Estimated attrition rates for pole mounted transformers on Hydro One Distribution's system are very low (i.e. 1% to 2% per annum). Much of this attrition occurs at random locations due to storm damage, lighting damage, and other causes. As a result, feeders will still need to be inspected in their entirety to ensure that all pre-1985 units are identified and tested. However, attrition will result in direct savings on testing costs. Testing makes up approximately 30% of the proposed 2010 and 2011 expenditures (i.e. $5.5M and $10.8M respectively) while inspections make up the remaining 70%. Therefore, for each year that inspection and testing is postponed, attrition will yield an estimated savings of $50k or less on the 2010 expenditures, and $100k or less on the 2011 expenditures.

Hydro One Distribution's proposal is to avoid a future spike in the work program by smoothing the expenditure levels from 2011 to the period leading up to the 2025 deadline. Hydro One believes this approach strikes an appropriate balance between the savings from attrition (i.e. equipment will be deferred until 2024)

- Proceeding with the work is prudent from an environmental perspective as PCB information will enable better management of wastes and oil spills should transformer failures occur.

- Proceeding with the work is aligned with Hydro One's commitment to environmental stewardship and is viewed favourably by Environment Canada as it will enable proactive retirements of PCB contaminated equipment.

- Postponing inspections and testing will result in the need for significant annual expenditures in the years leading up to the 2025 deadline for which labour resources may not be available.

- Smoothing the level of expenditures necessary to address PCB contaminated equipment will mitigate the rate impacts on Hydro One Distribution's customers.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch 2/p25

Sustaining OM&A – Other Services: Costs are forecast to increase by 17% in 2010 to $12.5 million after remaining steady at the $10.7 million level for 2008 and 2009. The explanation provided cites "historic customer demands" and an increase in Health and Safety programs. Why do the Health and Safety programs require expansion in the test years? Please provide evidence that shows that these programs were inadequate and require additional expenditures.

Response

The increase in the Health and Safety program costs for the test years is related to expansion of current initiatives and new initiatives aimed at meeting Hydro One's strategic objective of creating an injury free workforce. Also included in Health and Safety programs are trades and technical training programs. Training requirements are increasing in the test years due to the influx of new staff required to complete the planned work program and replace those who will retire in future years.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch 2/p28

Sustaining OM&A – Metering: Hydro One is installing Smart Meters to replace conventional Customer Retail Meters. In Table 8, cost increases are shown for Customer Retail Meters, Smart Meters and Telecom and Control. For instance, costs grow from $6.6 million to $13 million to $14.7 million from 2009 to 2011. Why do costs not decrease for Customer Retail Meters as they are replaced by Smart Meters?

Response

The costs associated with the Customer Retail Meters component of this program is for routine inspection, maintenance and accuracy verification of Hydro One's 1.2 million revenue meters. This program component captures the cost of these activities for all meter types, both Smart or legacy mechanical.

Smart Meters, by virtue of the fact that they have telecommunication and report hourly readings, will incur new ongoing costs that did not exist previously with legacy meters. These new costs are shown as under the Smart Meter component of the program, and as described in section 2.3.3 of Exhibit C1, Tab 2, Schedule 2 they include license and maintenance fees to the vendors, cost for the telecommunication services to collect the hourly readings each day, maintenance costs for the central systems that perform the data polling and storage functions, costs to operate the meter telecom network and cost to maintain the new billing system components that interface with the meter data repository (MDM/R) operated by the IESO.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

26. Ref: ExhC1/Tab2/Sch 3/p4
The evidence references a proactive approach to load flow studies, etc. which result in significant increases in Development O&M. Did Hydro One consider reducing studies in other areas to mitigate the budgeted increases in the test years?

Response

Yes. The budget proposed for the test years is based on the investment planning and prioritization process described in Exhibit A, Tab 14, Schedules 5 and 6 that consider trade-offs between spending on different programs. Application of the planning and prioritization process results in a set of investments and work programs that effectively balance our asset needs with due consideration for resource availability and the mitigation of risk to Hydro One's business values. Hydro One considers the proposed OM&A test year expenditures to be prudent and does not recommend a reduction in the budget.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch 4/p1-2

Please provide a table showing the total costs of the Hydro One Ontario Grid Control Centre, and the (Rudden based) allocated costs to both the Transmission and Distribution businesses from 2004 to 2011. If significant shifts in costs between the businesses are evident from year to year, please provide the rationale for such cost shifts. Are other Operations costs also allocated between Transmission and Distribution or are all other costs stand alone distribution?

Response

As shown in Table 1 on page 5 of Exhibit C1, Tab2, Schedule 4, total Operations OM&A can be divided into two programs – "Operations" and "Operating Support".

The following table shows the 2 major components of Operations OM&A and the allocated costs to both the Transmission and Distribution businesses from 2004 to 2011.

	2004	2005	2006	2007	2008	2009	2010	2011
Operations Contracts	3.3	3.2	4.1	4.1	3.7	2.9	4.3	4.8
Operations (Transmission & Distribution)	51.3	33.6	38.3	36.9	37.9	42.0	44.3	45.6
Distribution Operations ($)	13.0	8.1	10.8	8.5	8.7	9.7	12.4	12.8
Transmission Operations ($)	38.3	25.5	27.4	28.4	29.1	32.3	31.9	32.8
Distribution Operations (%)	25%	24%	28%	23%	23%	23%	28%	28%
Transmission Operations (%)	75%	76%	72%	77%	77%	77%	72%	72%
Total "Distribution Operations"	16.3	11.2	14.9	12.6	12.4	12.6	16.7	17.6

Note - all figures in $M

Please note that "Operations Contracts" is stand-alone Distribution and does not require allocation between Transmission and Distribution. The Distribution portion of "Operations" was determined based on the Asset Management Time Study. Hydro One does not believe there is significant shift in "Operations" costs between the Transmission and Distribution businesses from year to year.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: ExhC1/Tab2/Sch 4/p7

Operations O&M increases by 11.5% in 2009 and a further 28% in 2010. The evidence references an increase in OGCC staff to focus on distribution elements. How many additional staff were added to the OGCC? Why are such significant resource additions required so far in advance of actual implementation of the bulk of the distributed generation and Smart Grid?

Response

In 2009, one additional staff was added to work on developmental aspects of the implementation of distributed generation and Smart Grid. In addition, five university graduates were hired into the two year Hydro One grad trainee program in preparation of the anticipated retirements due to the aging demographics of OGCC staff. The current plan is to add an additional twelve staff in 2010 for the implementation of distributed generation and smart grid and a further eight in 2011. This requirement is for systems and process that need to be established in advance of the generators coming on line. Also, our plan assumes that there will be generation connected in the test year period and OGCC staff will be required to manage those new connections.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

29. Ref: ExhA/Tab16/Sch1/p4

Hydro One mentions two benchmarking studies, First Quartile and the CEA. Please provide copies of the most recent study results.

Response

The most recent First Quartile (latest data 2007) study results are provided in Attachments 1-10. The CEA Service Continuity (latest data 2008) study is provided in Attachment 11.

3-year Graphs

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2| 3-year Recordable Incident Rate: Substations

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2| 3-year Lost Time Incident Rate: Total T&D

2| 3-year Lost Time Incident Rate: Transmission Lines

2| 3-year Lost Time Incident Rate: Substations

2| 3-year Lost Time Incident Rate: Distribution Lines

2| 3-year Lost Time Severity Rate: Total T&D

2| 3-year Lost Time Severity Rate: Transmission Lines

2| 3-year Lost Time Severity Rate: Substations

2| 3-year Lost Time Severity Rate: Distribution Lines

2| 3-year Vehicle Incident Rate: Total T&D

2| 3-year Vehicle Incident Rate: Transmission Lines

2| 3-year Vehicle Incident Rate: Substations

2| 3-year Vehicle Incident Rate: Distribution Lines

Distribution Reliability

2| 3-year SAIDI (Including Major Events and Planned Interruptions)

2| 3-year SAIDI (Excluding Major Events and Planned Interruptions)

2| 3-year SAIDI (Excluding Major Events)

2| 3-year SAIDI (Excluding Transmission & Generation outages)

2| 3-year SAIDI (Excluding Major Events using 2.5 beta method)

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2| 3-year SAIFI (Including Major Events and Planned Interruptions)

2| 3-year SAIFI (Excluding Major Events and Planned Interruptions)

2| 3-year SAIFI (Excluding Major Events)

2| 3-year SAIFI (Excluding Major Events using 2.5 beta method)

2| 3-year CAIDI (Including Major Events and Planned Interruptions)

2| 3-year CAIDI (Excluding Major Events and Planned Interruptions)

2| 3-year CAIDI (Excluding Major Events)

2| 3-year CAIDI (Excluding transmission or generation events)

2| 3-year CAIDI (Excluding Major Events using 2.5 beta method)

2| 2006YE SAIDI (Including Major Events and Planned Interruptions)

2| 2006YE SAIDI (Excluding Major Events and Planned Interruptions)

3| 2005YE SAIDI (Including Major Events and Planned Interruptions)

3| 2005YE SAIDI (Excluding Major Events and Planned Interruptions)

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2| 2006YE SAIFI (Excluding Major Events and Planned Interruptions)

3| 2005YE SAIFI (Including Major Events and Planned Interruptions)

2| 2005YE SAIFI (Excluding Major Events and Planned Interruptions)

2| 2006YE CAIDI (Including Major Events and Planned Interruptions)

2| 2006YE CAIDI (Excluding Major Events and Planned Interruptions)

2| 2005YE CAIDI (Including Major Events and Planned Interruptions)

2| 2005YE CAIDI (Excluding Major Events and Planned Interruptions)

Substation Reliability

1| 3-Year Substation contribution to SAIDI: Distribution Substations

1| 3-year Substation contribution to SAIDI: Transmission Substations

1| 3-Year Substation contribution to SAIFI: Distribution Substations

1| 3-year Substation contribution to SAIFI: Transmission Substations

3| 3-year Correct operations rate [percent of total operations] for relays: Transmission Substations

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Financial

2005 Distribution Lines O&M Expense per Circuit Mile

2006 Distribution Lines O&M Expense per Circuit Mile

3-Year Distribution Lines O&M Expense per Circuit Mile

2005YE Transmission Lines O&M Expense per Circuit Mile

2006YE Transmission Lines O&M Expense per Circuit Mile

3-year Transmission Lines O&M Expense per Circuit Mile

3-Yr Transmission Line Capital Spending less New Transmission Lines per Asset

3-year Distribution Substation Capital Spending per Asset

3-Year Distribution Substation O&M Expense per Installed MVA

2005 Distribution Substation Capital Spending per Asset

2005 Distribution Substation O&M Expense per Installed MVA

2006 Distribution Substation Capital Spending per Asset

2006 Distribution Substation O&M Expense per Installed MVA

3-year Transmission Substation O&M Expense per Installed MVA

2005 Transmission Substation O&M Expense per Installed MVA

2006 Transmission Substation O&M Expense per Installed MVA

2005 Transmission Substation Capital Spending per Asset

2006 Transmission Substation Capital Spending per Asset

3-year Transmission Substation Capital Spending per Asset

3-Year Distribution Substation O&M Expense per Asset

3-year Transmission Substation O&M Expense per Asset

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2| 3-YEAR RECORDABLE INCIDENT RATE - TOTAL T&D



Mean Quartile	
Mean	11.43
Quartile 1	4.17
Quartile 2:	7.67
Quartile 3:	12.50

Comments

Calculation used

Q1.1A, Q2.1A, Q3.1A

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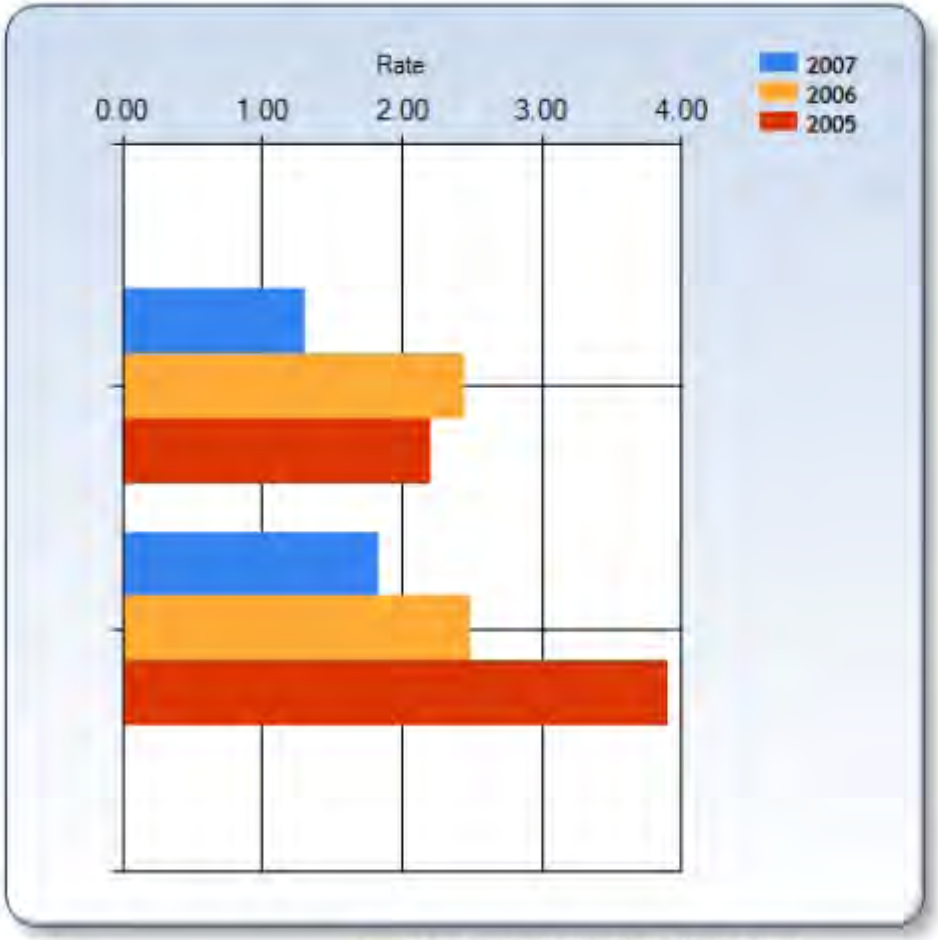
2| 3-YEAR RECORDABLE INCIDENT RATE: TRANSMISSION LINES



Mean Quartile	
Mean	7.11
Quartile 1	6.54
Quartile 2:	7.11
Quartile 3:	7.67

Comments

Calculation used

Q1.1B, Q2.1B, Q3.1B

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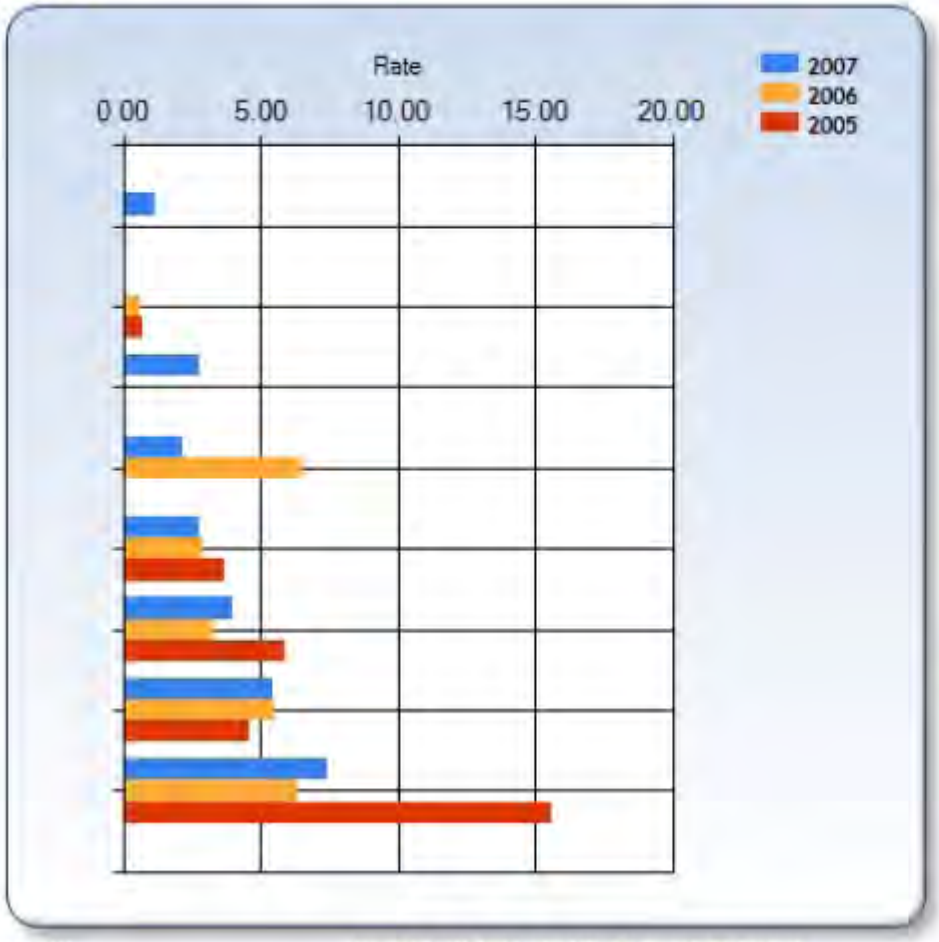
2| 3-YEAR RECORDABLE INCIDENT RATE: SUBSTATIONS



Mean Quartile	
Mean	10.21
Quartile 1	2.45
Quartile 2:	9.01
Quartile 3:	13.83

Comments

Calculation used

Q1.1C, Q2.1C, Q3.1C

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2| 3-YEAR RECORDABLE INCIDENT RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	14.27
Quartile 1	7.97
Quartile 2:	12.15
Quartile 3:	14.57

Comments

Calculation used

Q1.1D, Q2.1D, Q3.1D

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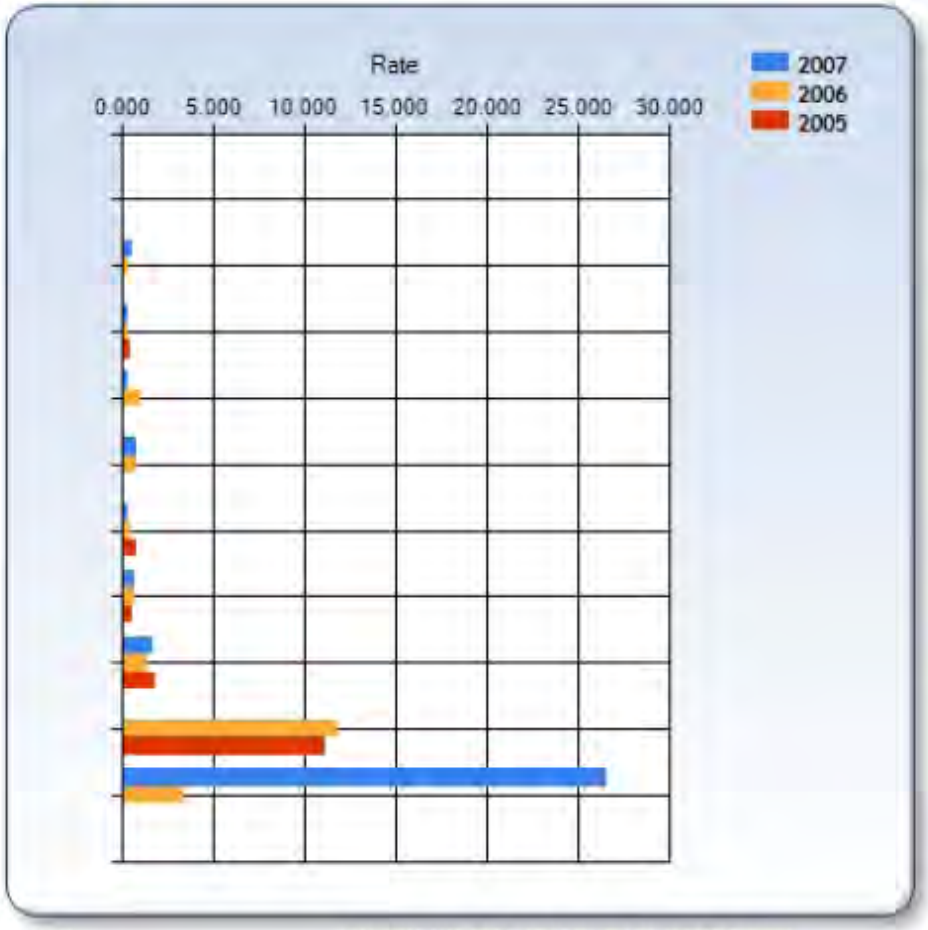
2| 3-YEAR LOST TIME INCIDENT RATE: TOTAL T&D



Mean Quartile	
Mean	6.784
Quartile 1	1.268
Quartile 2:	1.758
Quartile 3:	4.328

Comments

Calculation used

Q1.2A, Q2.2A, Q3.2A

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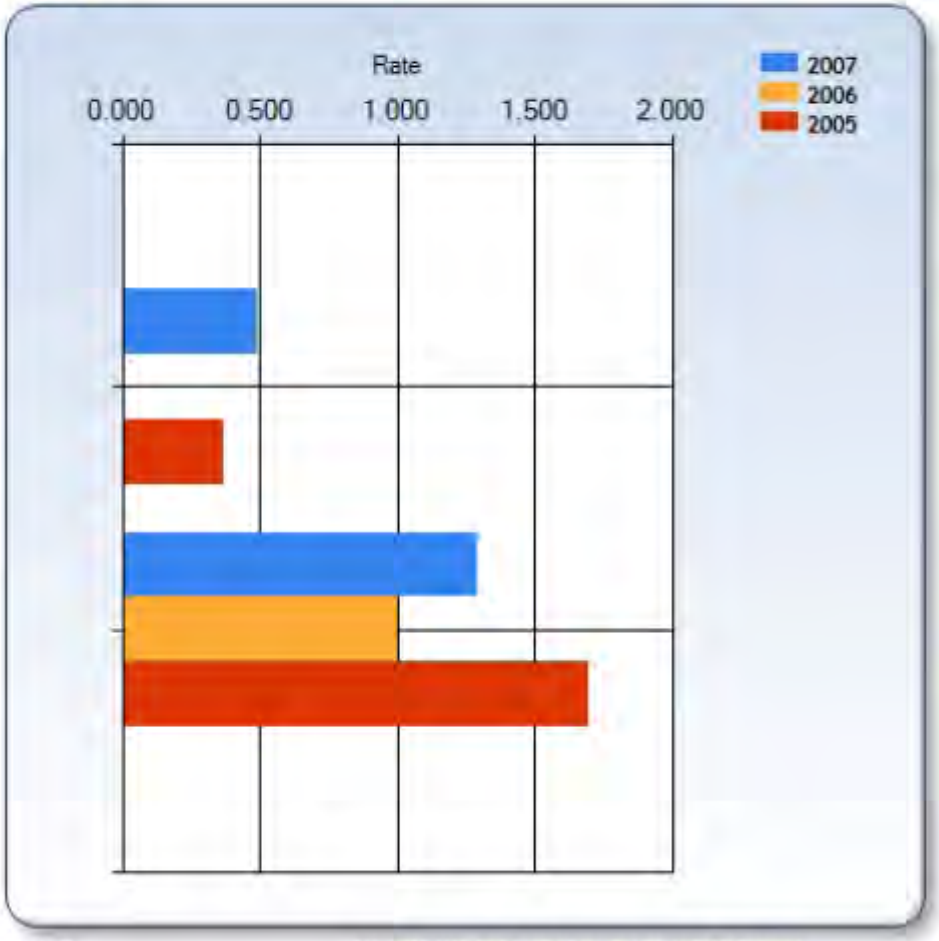
2| 3-YEAR LOST TIME INCIDENT RATE: TRANSMISSION LINES



Mean Quartile	
Mean	2.425
Quartile 1	1.643
Quartile 2:	2.425
Quartile 3:	3.208

Comments

Calculation used

Q1.2B, Q2.2B, Q3.2B

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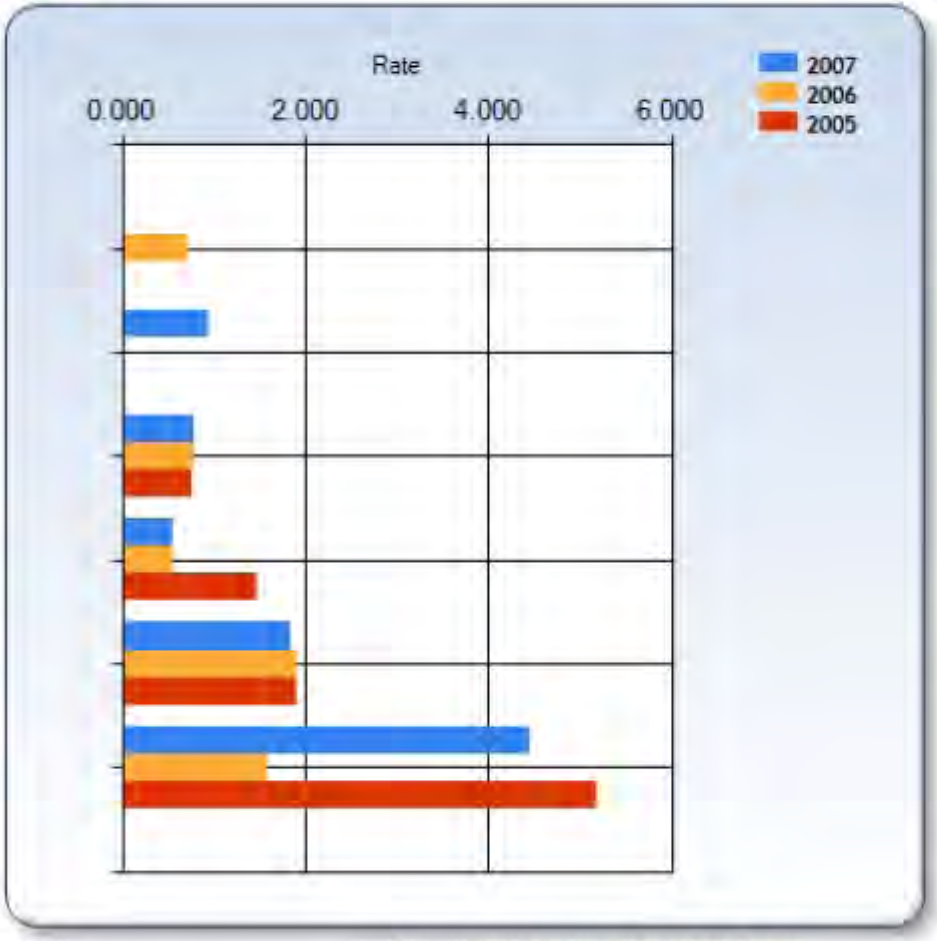
2| 3-YEAR LOST TIME INCIDENT RATE: SUBSTATIONS



Mean Quartile	
Mean	3.918
Quartile 1	1.290
Quartile 2:	2.473
Quartile 3:	4.889

Comments

Calculation used

Q1.2C, Q2.2C, Q3.2C

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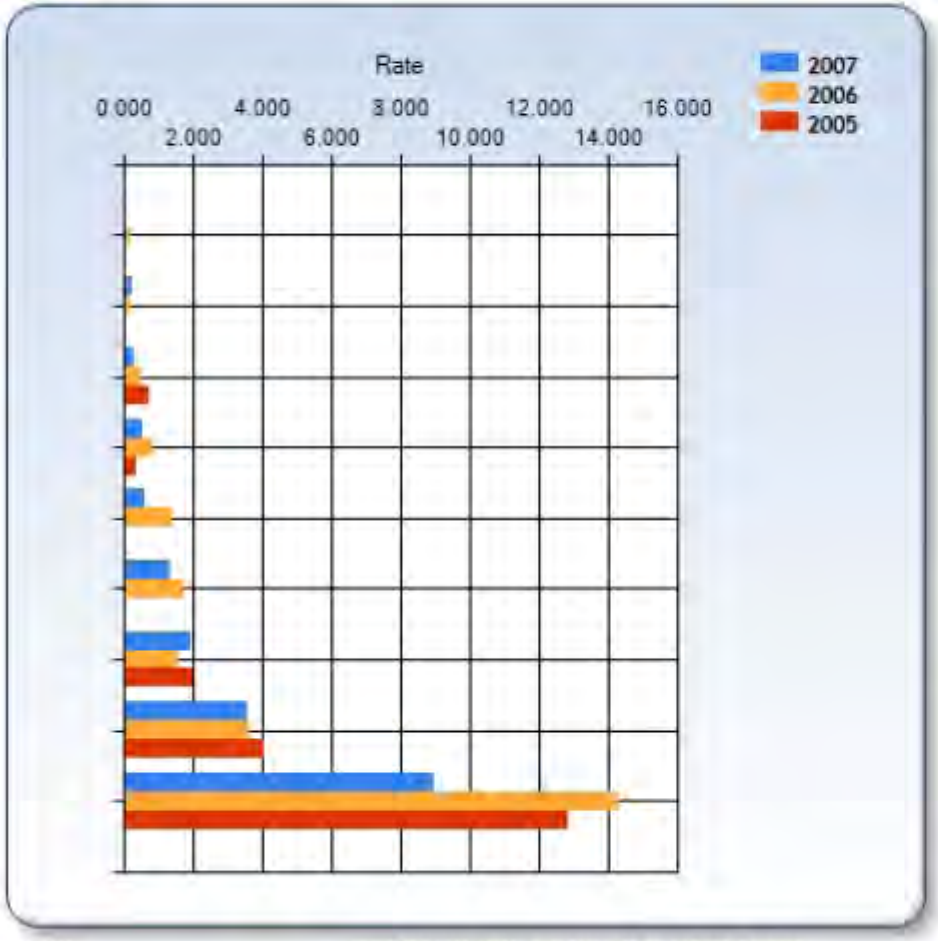
2| 3-YEAR LOST TIME INCIDENT RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	6.954
Quartile 1	1.648
Quartile 2:	2.060
Quartile 3:	5.550

Comments

Calculation used

Q1.2D, Q2.2D, Q3.2D

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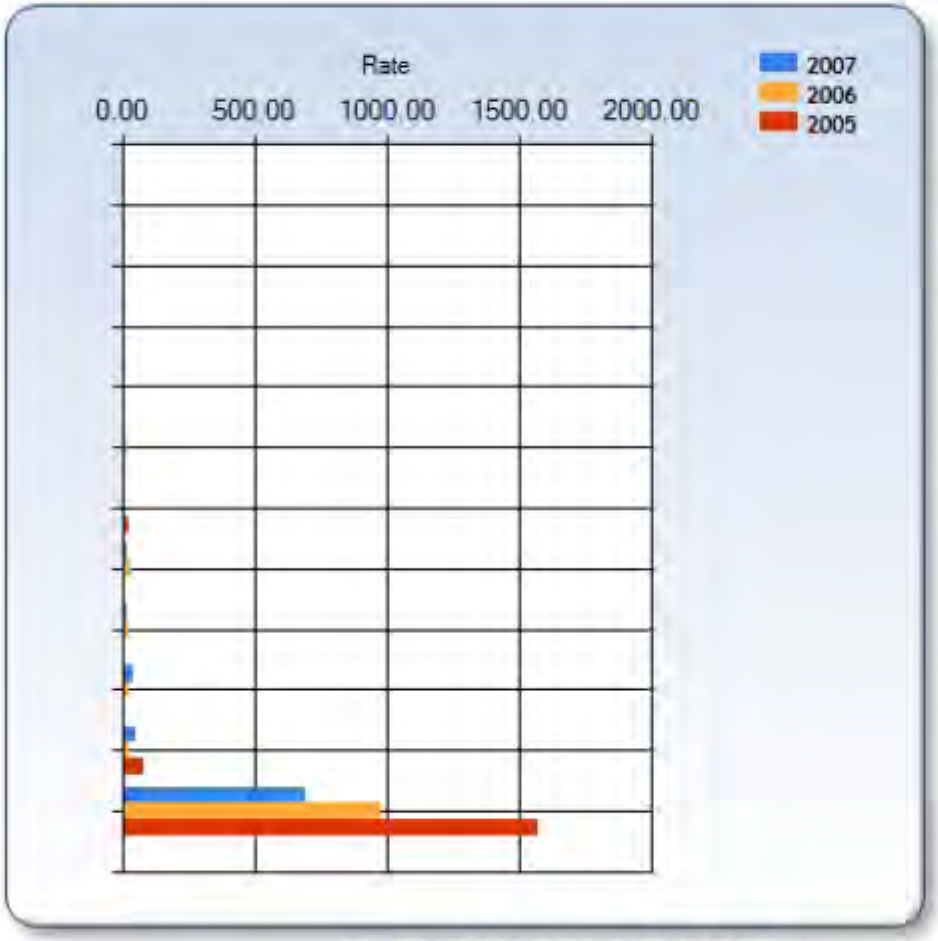
2| 3-YEAR LOST TIME SEVERITY RATE: TOTAL T&D



Mean Quartile	
Mean	339.95
Quartile 1	22.72
Quartile 2:	50.03
Quartile 3:	63.19

Comments

Calculation used

Q1.3A, Q2.3A, Q3.3A

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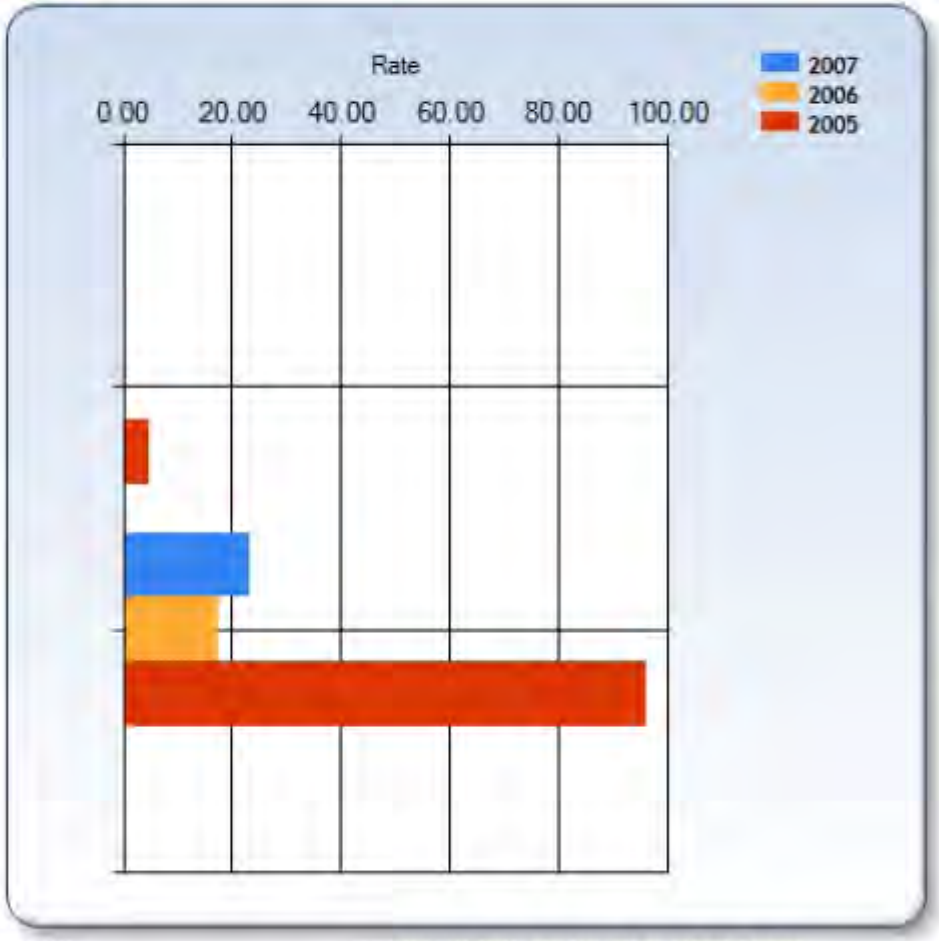
2| 3-YEAR LOST TIME SEVERITY RATE: TRANSMISSION LINES



Mean Quartile	
Mean	71.12
Quartile 1	38.05
Quartile 2:	71.12
Quartile 3:	104.19

Comments

Calculation used

Q1.3B, Q2.3B, Q3.3B

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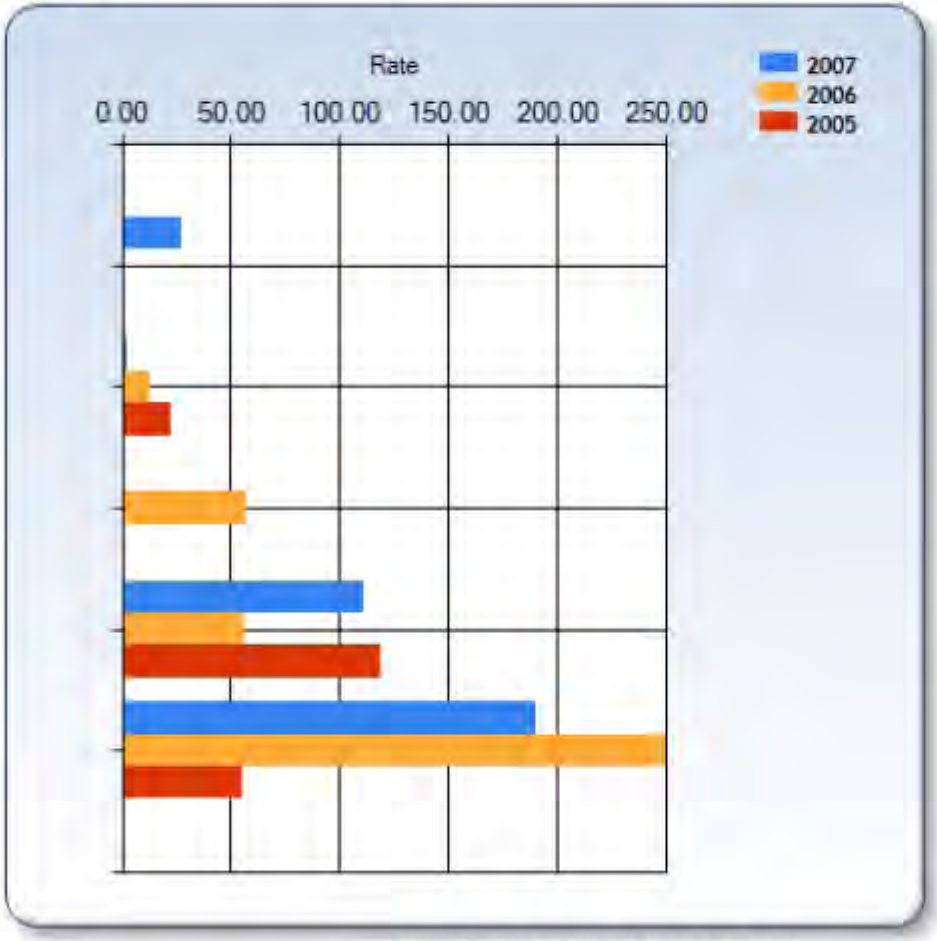
2| 3-YEAR LOST TIME SEVERITY RATE: SUBSTATIONS



Mean Quartile	
Mean	181.11
Quartile 1	38.30
Quartile 2:	57.03
Quartile 3:	287.45

Comments

Calculation used

Q1.3C, Q2.3C, Q3.3C

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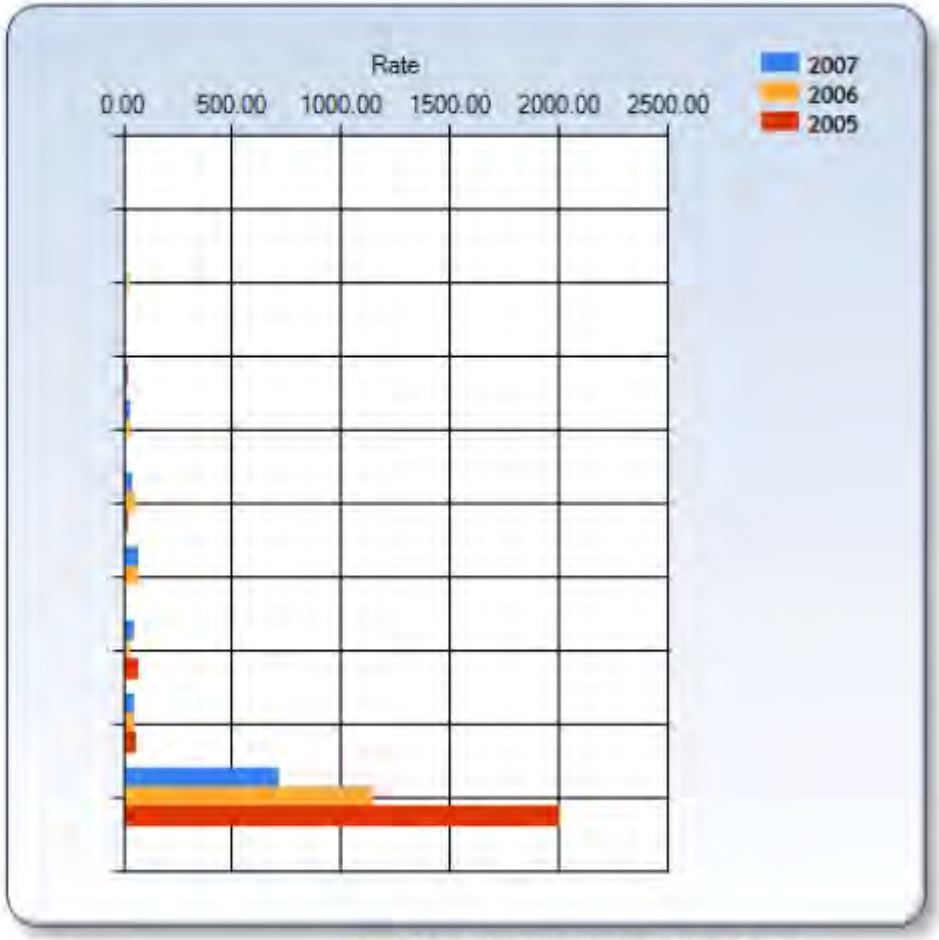
2| 3-YEAR LOST TIME SEVERITY RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	516.17
Quartile 1	51.85
Quartile 2:	124.50
Quartile 3:	152.47

Comments

Calculation used

Q1.3D, Q2.3D, Q3.3D

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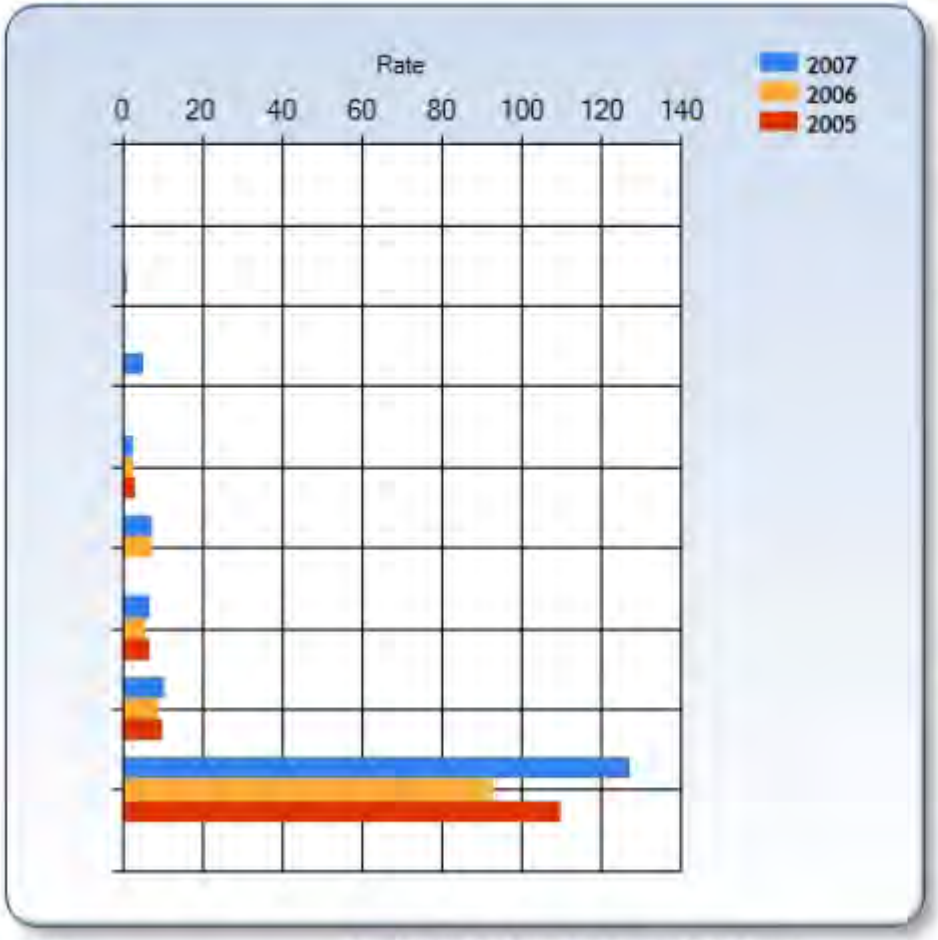
2| 3-YEAR VEHICLE INCIDENT RATE: TOTAL T&D



Mean Quartile	
Mean	51.75
Quartile 1	4.67
Quartile 2:	12.19
Quartile 3:	22.50

Comments

Calculation used

Q1.4A, Q2.4A, Q3.4A

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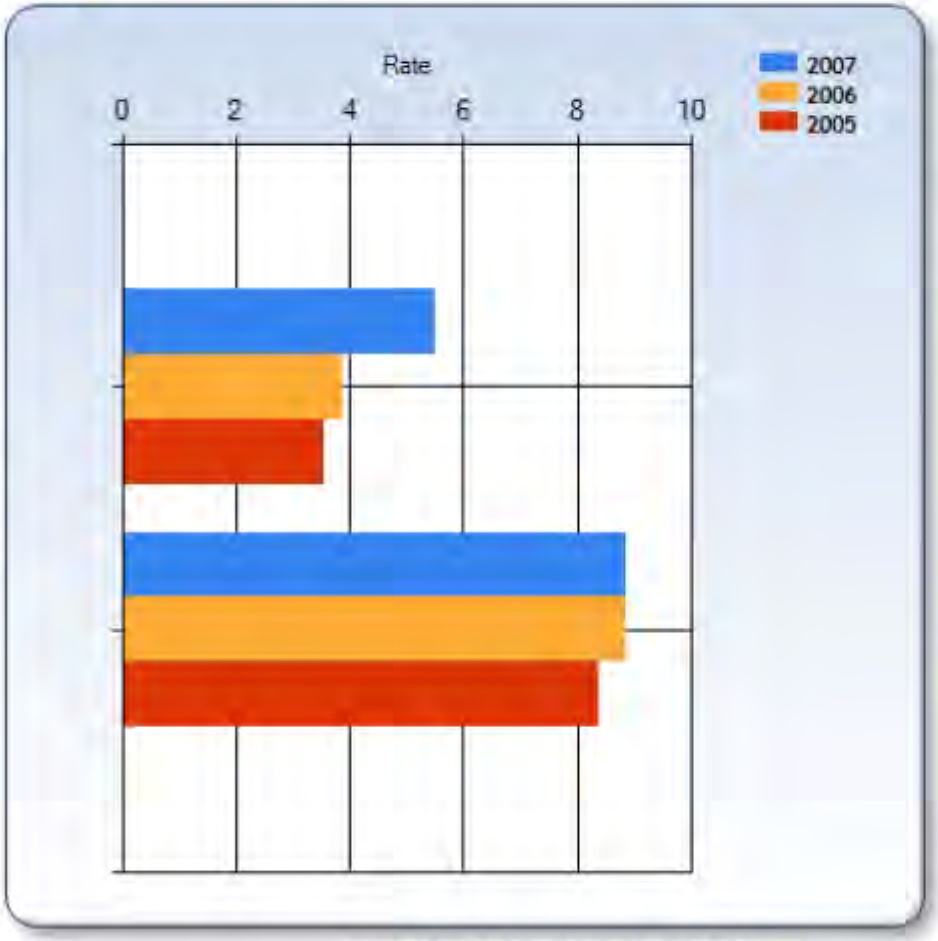
2| 3-YEAR VEHICLE INCIDENT RATE: TRANSMISSION LINES



Mean Quartile	
Mean	19.53
Quartile 1	16.23
Quartile 2:	19.53
Quartile 3:	22.82

Comments

Calculation used

Q1.4B, Q2.4B, Q3.4B

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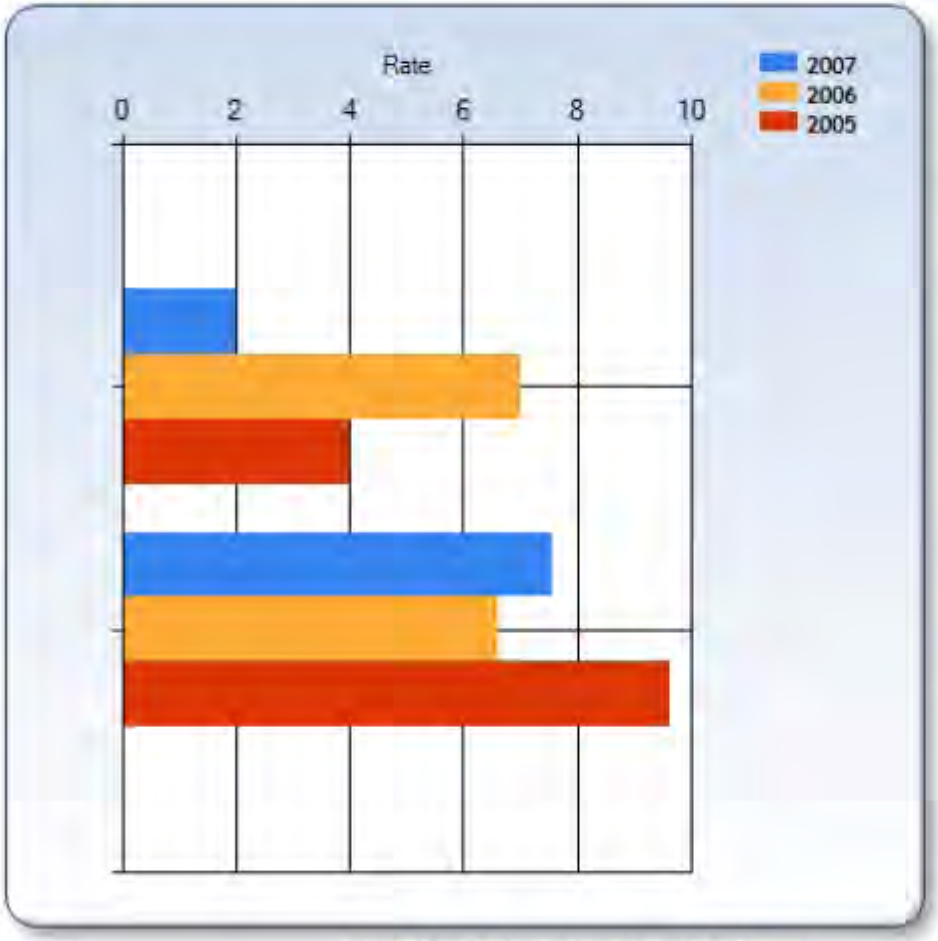
2| 3-YEAR VEHICLE INCIDENT RATE: SUBSTATIONS



Mean Quartile	
Mean	18.40
Quartile 1	15.70
Quartile 2	18.40
Quartile 3	21.09

Comments

Calculation used

Q1.4C, Q2.4C, Q3.4C

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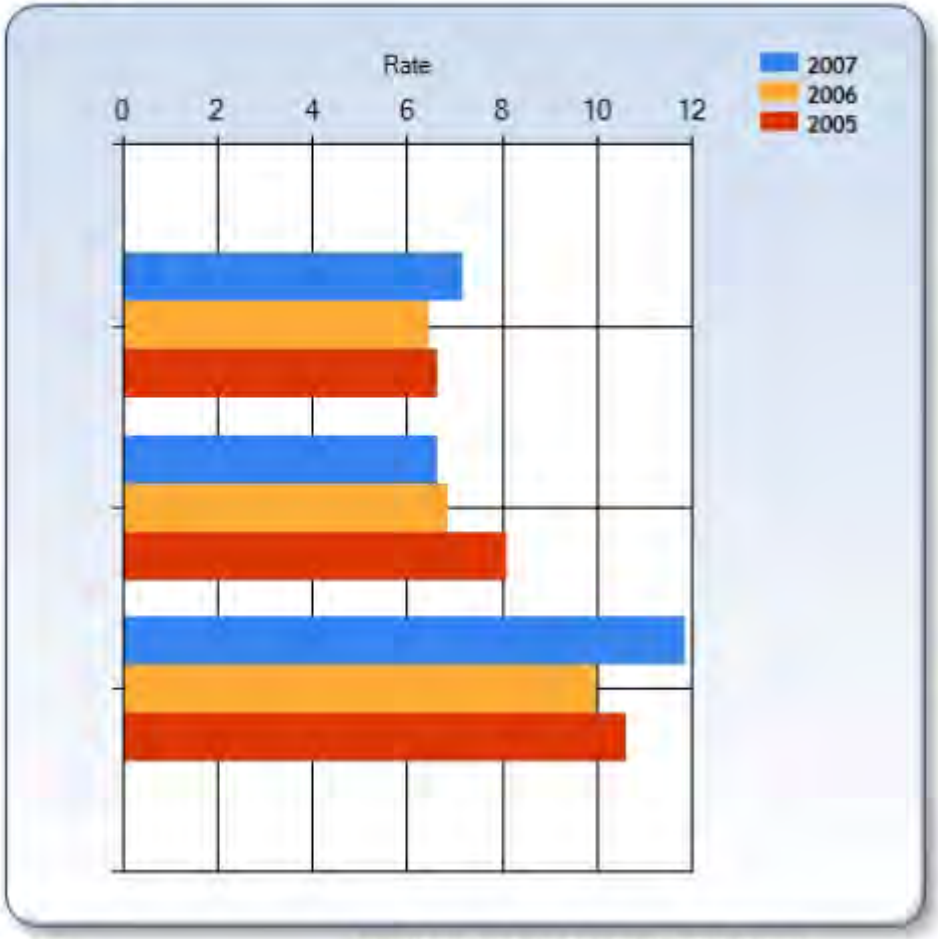
2| 3-YEAR VEHICLE INCIDENT RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	24.81
Quartile 1	20.96
Quartile 2:	21.63
Quartile 3:	27.08

Comments

Calculation used

Q1.4D, Q2.4D, Q3.4D

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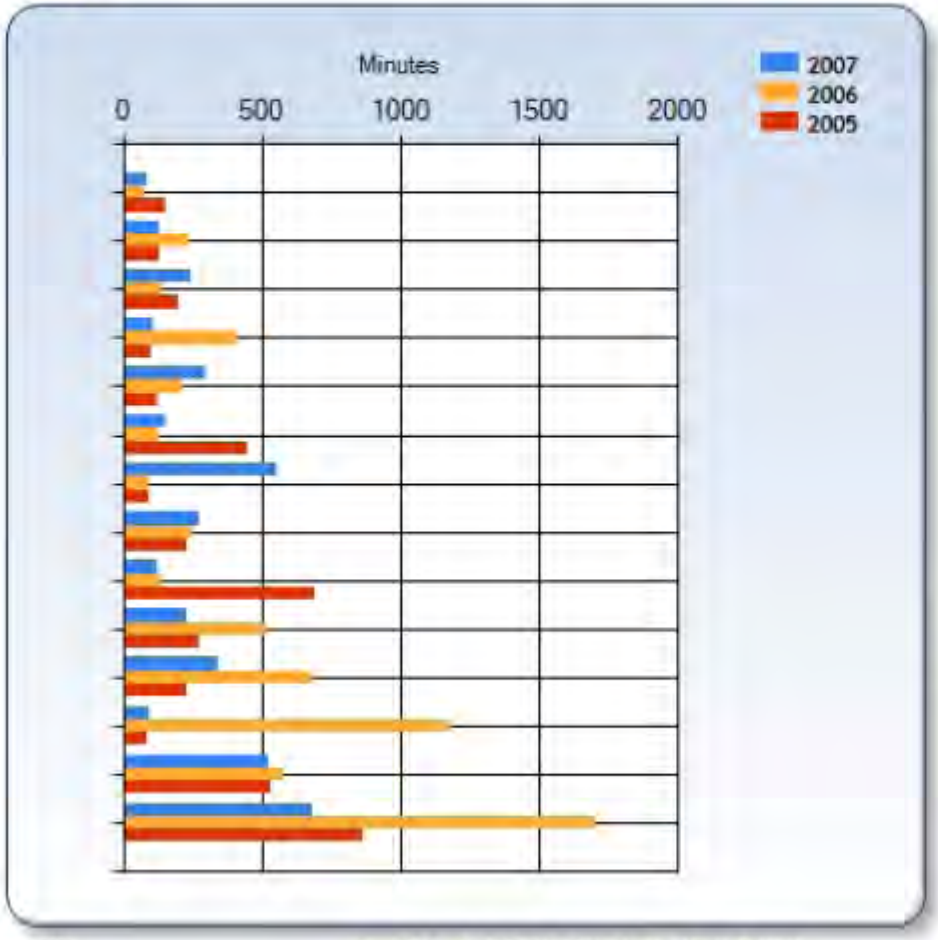
2| 3-YEAR SAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1031
Quartile 1	629
Quartile 2:	755
Quartile 3:	1198

Comments

Calculation used

Q1.1A, Q2.1A, Q3.1A

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2| 3-YEAR SAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	413
Quartile 1	269
Quartile 2:	342
Quartile 3:	443

Comments

Calculation used

Q1.1B, Q2.1B, Q3.1B

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2| 3-YEAR SAIDI (EXCLUDING MAJOR EVENTS)



Mean Quartile	
Mean	497
Quartile 1:	274
Quartile 2:	400
Quartile 3:	540

Comments

Calculation used

Q1.1C, Q2.1C, Q3.1C

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2| 3-YEAR SAIDI (EXCLUDING TRANSMISSION & GENERATION OUTAGES)



Mean Quartile	
Mean	703
Quartile 1	516
Quartile 2:	656
Quartile 3:	934

Comments

Calculation used

Q1.1D, Q2.1D, Q3.1D

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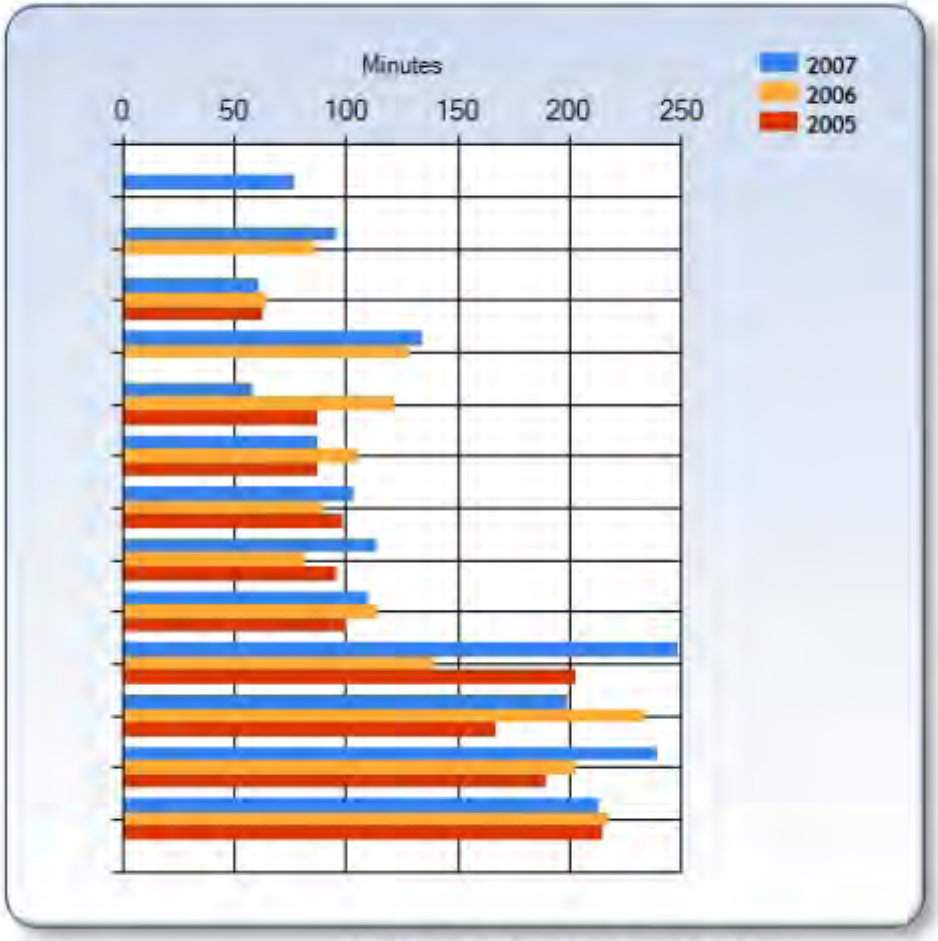
2| 3-YEAR SAIDI (EXCLUDING MAJOR EVENTS USING 2.5 BETA METHOD)



Mean Quartile	
Mean	357
Quartile 1	263
Quartile 2:	292
Quartile 3:	592

Comments

Calculation used

Q1.1E, Q2.1E, Q3.1E

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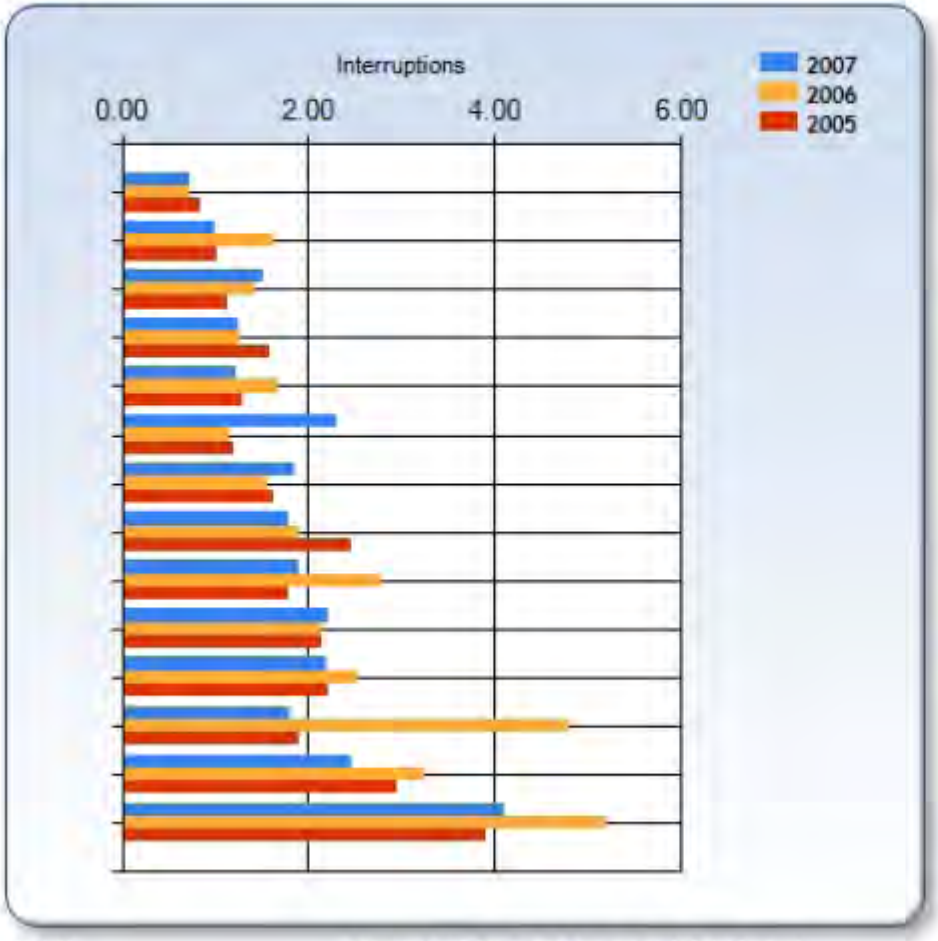
FIRST QUARTILE CONSULTING

2| 3-YEAR SAIFI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	6.03
Quartile 1	4.12
Quartile 2:	5.60
Quartile 3:	6.84

Comments

Calculation used

Q1.2A, Q2.2A, Q3.2A

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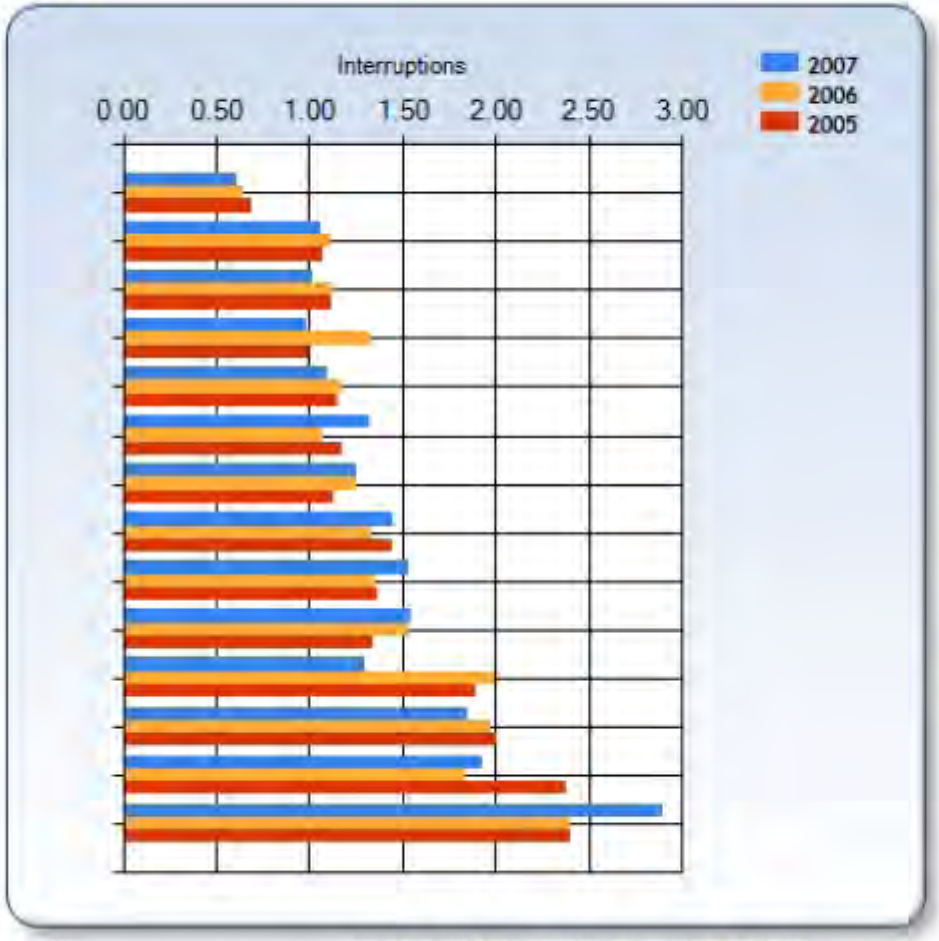
2| 3-YEAR SAIFI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	4.30
Quartile 1:	3.34
Quartile 2:	3.93
Quartile 3:	5.01

Comments

Calculation used

Q1.2B, Q2.2B, Q3.2B

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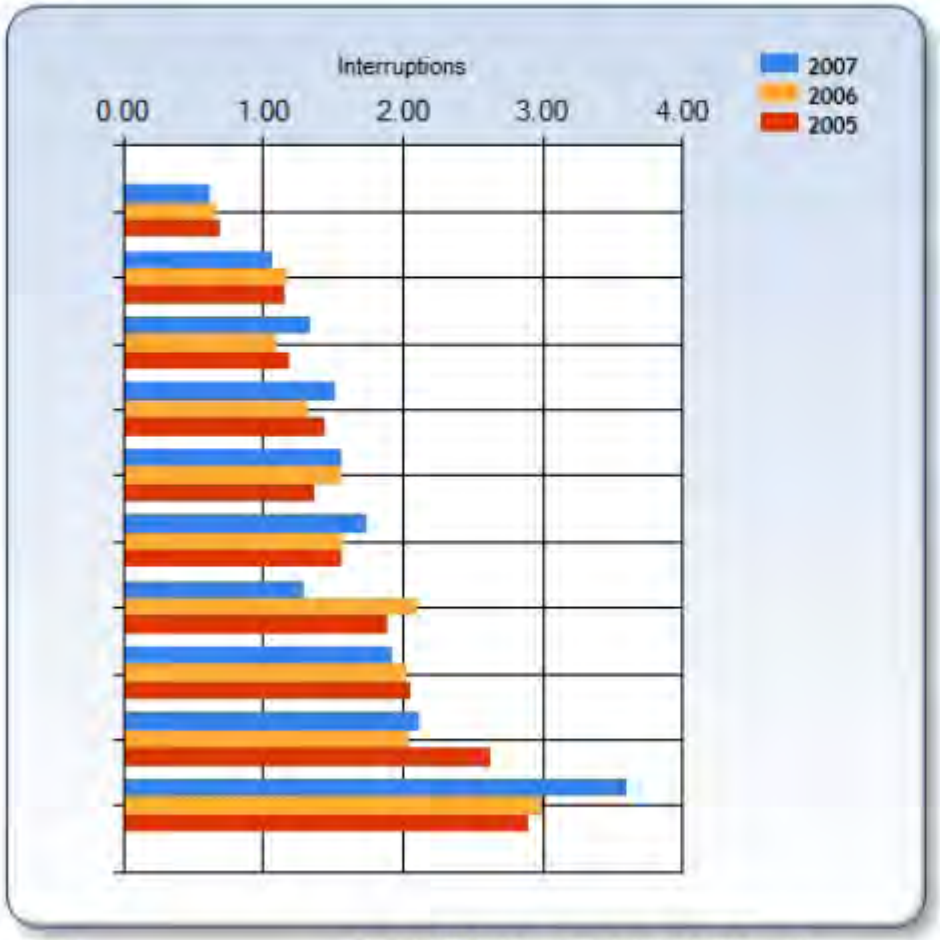
2| 3-YEAR SAIFI (EXCLUDING MAJOR EVENTS)



Mean Quartile	
Mean	5.04
Quartile 1	3.80
Quartile 2:	4.70
Quartile 3:	5.84

Comments

Calculation used

Q1.2C, Q2.2C, Q3.2C

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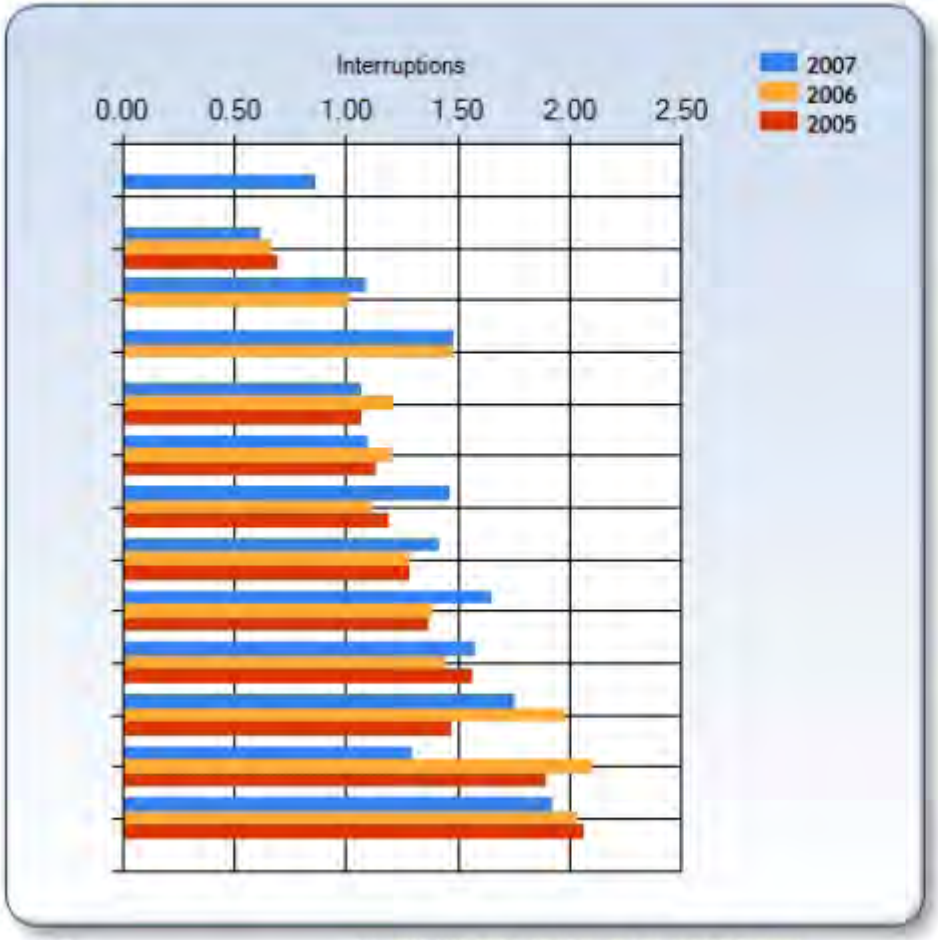
FIRST QUARTILE CONSULTING

2| 3-YEAR SAIFI (EXCLUDING MAJOR EVENTS USING 2.5 BETA METHOD)



Mean Quartile	
Mean	3.70
Quartile 1	2.97
Quartile 2:	3.78
Quartile 3:	4.60

Comments

Calculation used

Q1.2E, Q2.2E, Q3.2E

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FIRST QUARTILE CONSULTING

2| 3-YEAR CAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	457
Quartile 1	350
Quartile 2:	415
Quartile 3:	502

Comments

Calculation used

Q1.3A, Q2.3A, Q3.3A

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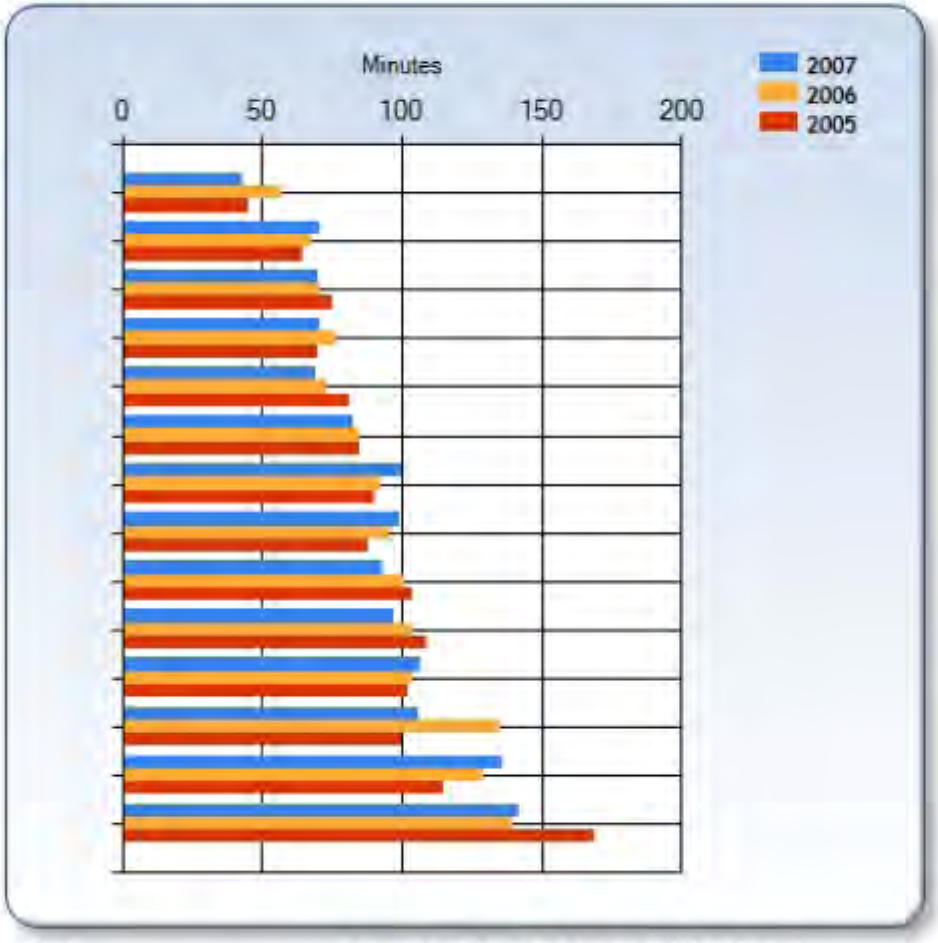
FIRST QUARTILE CONSULTING

2| 3-YEAR CAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	280
Quartile 1	219
Quartile 2:	283
Quartile 3:	312

Comments

Calculation used

Q1.3B, Q2.3B, Q3.3B

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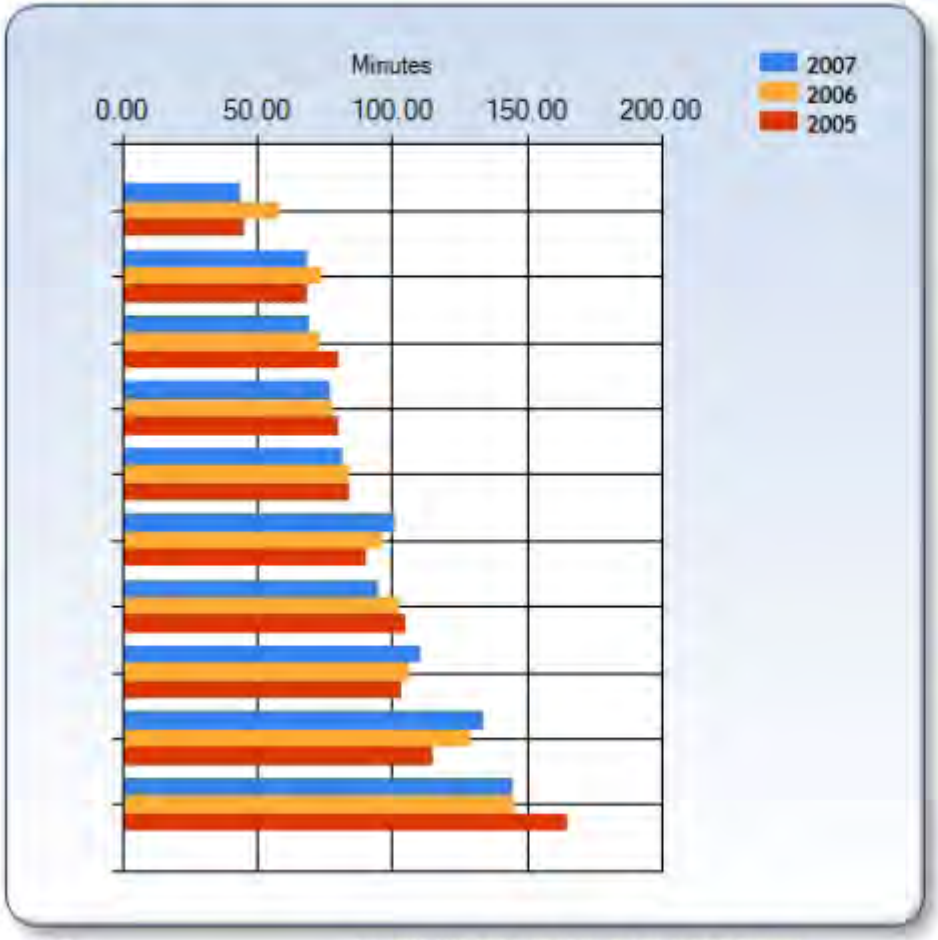
2| 3-YEAR CAIDI (EXCLUDING MAJOR EVENTS)



Mean Quartile	
Mean	281.80
Quartile 1	226.47
Quartile 2:	269.76
Quartile 3:	317.25

Comments

Calculation used

Q1.3C, Q2.3C, Q3.3C

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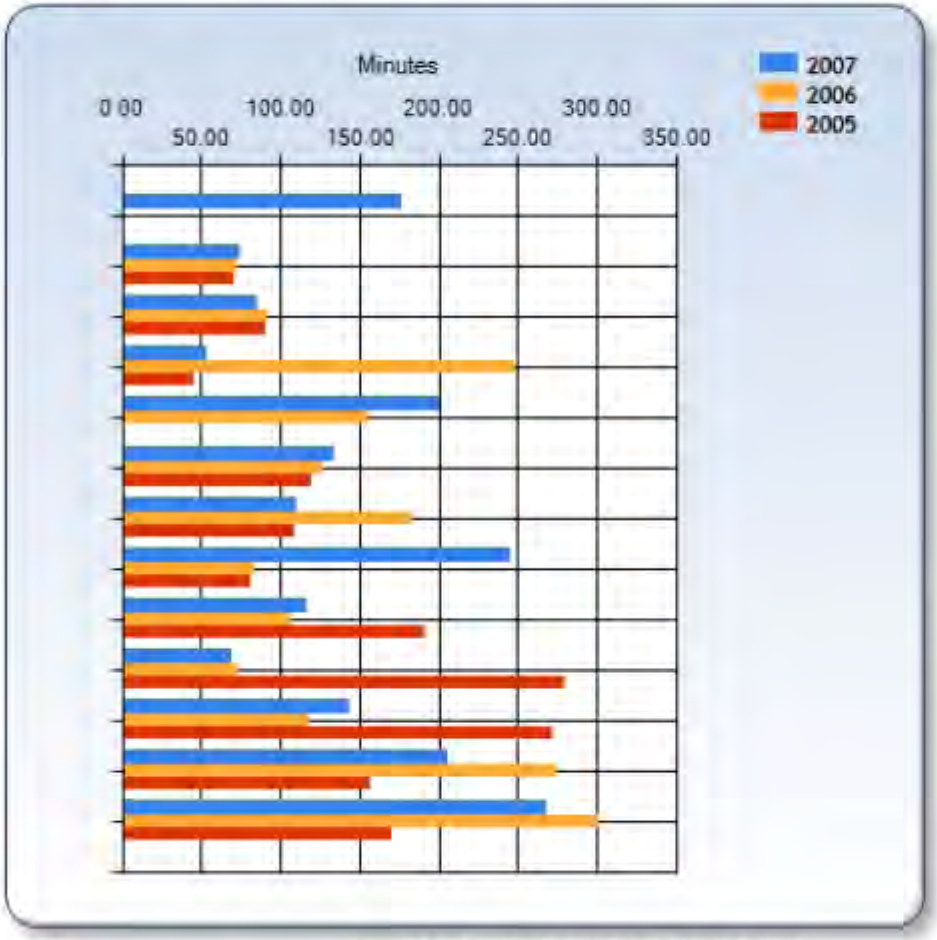
2| 3-YEAR CAIDI (EXCLUDING TRANSMISSION OR GENERATION EVENTS)



Mean Quartile	
Mean	408.30
Quartile 1	347.90
Quartile 2:	402.69
Quartile 3:	423.44

Comments

Calculation used

Q1.3D, Q2.3D, Q3.3D

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FIRST QUARTILE CONSULTING

2| 3-YEAR CAIDI (EXCLUDING MAJOR EVENTS USING 2.5 BETA METHOD)



Mean Quartile	
Mean	256.80
Quartile 1	177.00
Quartile 2:	251.00
Quartile 3:	322.00

Comments

Calculation used

Q1.3E, Q2.3E, Q3.3E

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FIRST QUARTILE CONSULTING

2| 2006YE SAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	456
Quartile 1	138
Quartile 2:	244
Quartile 3:	565

Comments

Calculation used

Q2.1A

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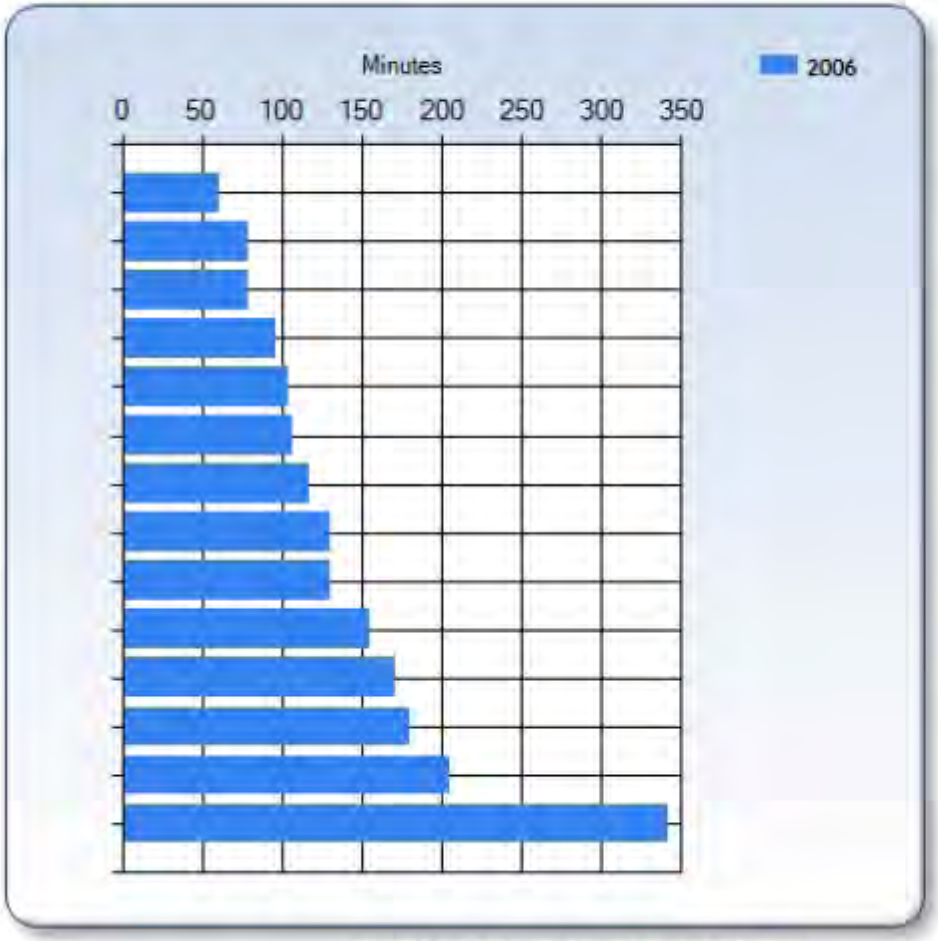
FIRST QUARTILE CONSULTING

2| 2006YE SAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	140
Quartile 1	98
Quartile 2	124
Quartile 3	167

Comments

Calculation used

Q2.1B

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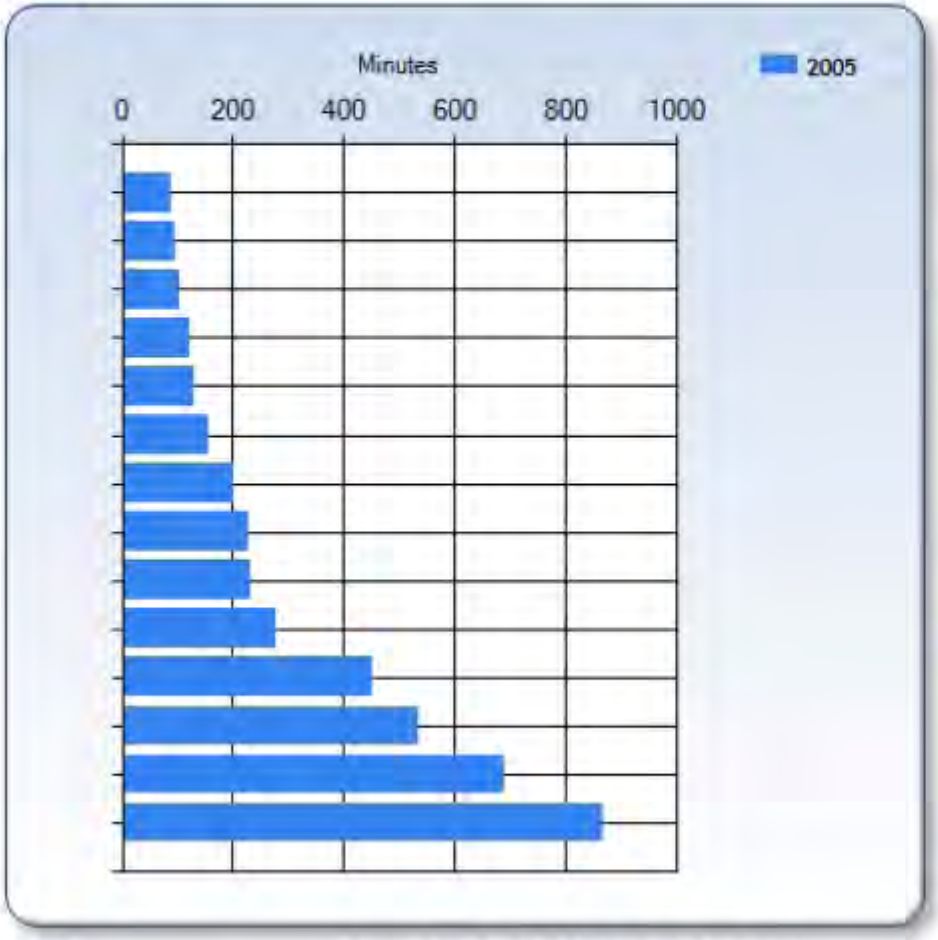
FIRST QUARTILE CONSULTING

3| 2005YE SAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	299
Quartile 1	126
Quartile 2:	216
Quartile 3:	409

Comments

Calculation used

Q3.1A

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FIRST QUARTILE CONSULTING

3| 2005YE SAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	138
Quartile 1	94
Quartile 2	98
Quartile 3	160

Comments

Calculation used

Q3.1B

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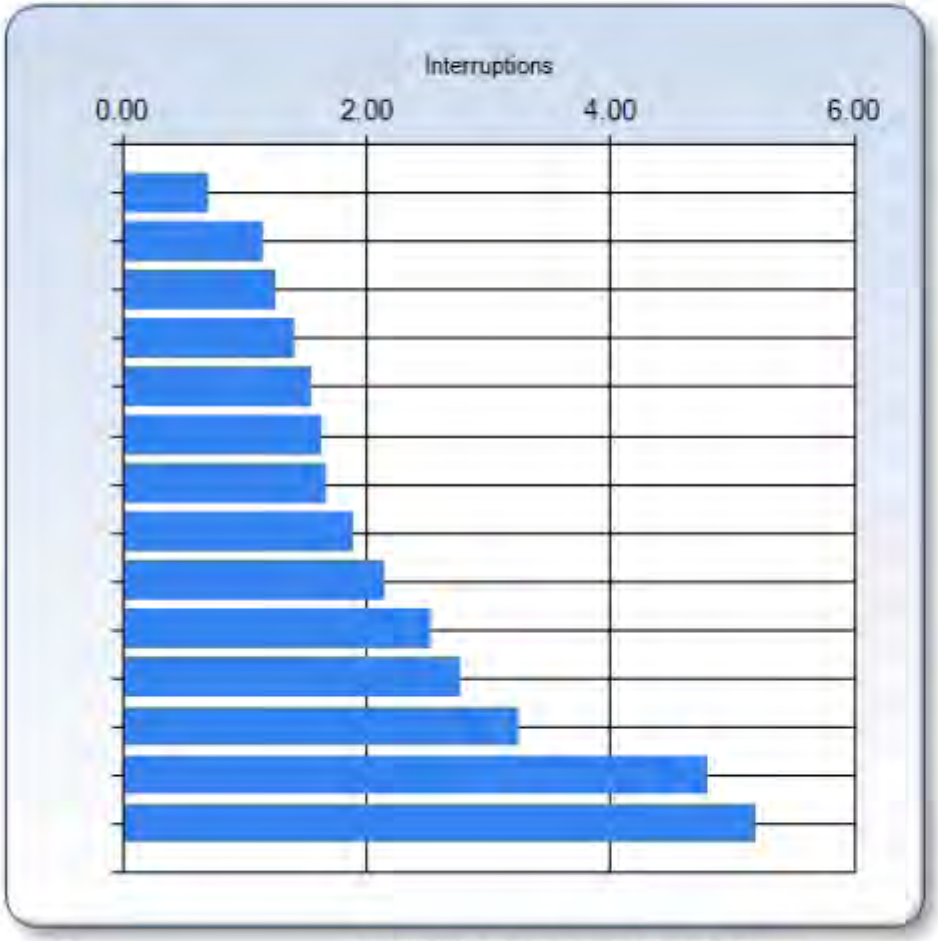
2| 2006YE SAIFI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	2.29
Quartile 1	1.46
Quartile 2	1.78
Quartile 3	2.72

Comments

Calculation used

Q2.2A

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FIRST QUARTILE CONSULTING

2| 2006YE SAIFI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1.44
Quartile 1	1.14
Quartile 2:	1.33
Quartile 3:	1.77

Comments

Calculation used

Q2.2B

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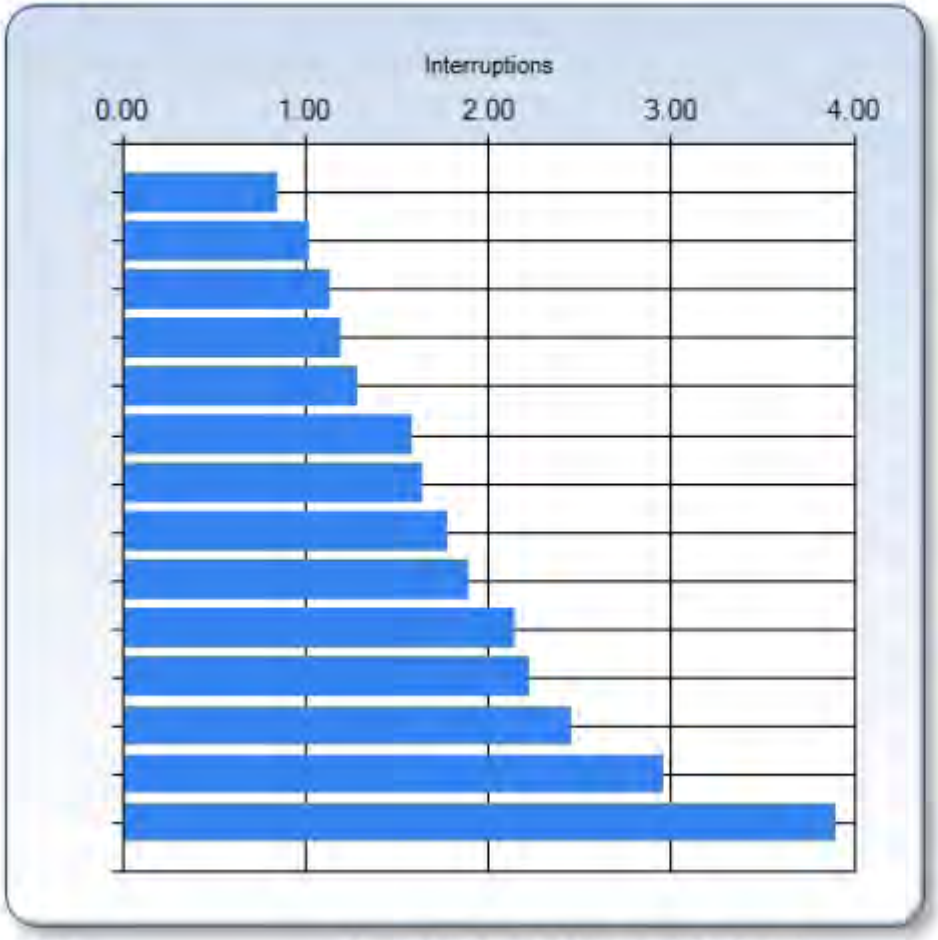
3| 2005YE SAIFI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1.86
Quartile 1	1.22
Quartile 2:	1.71
Quartile 3:	2.21

Comments

Calculation used

Q3.2A

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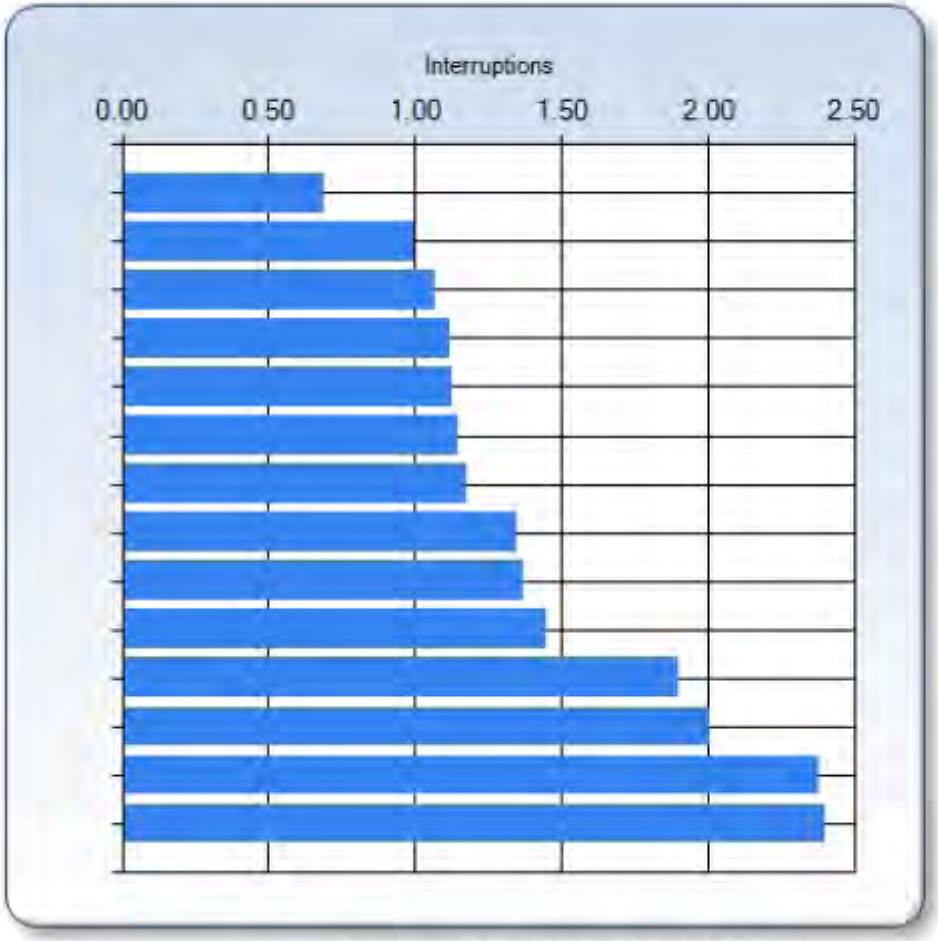
2| 2005YE SAIFI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1.44
Quartile 1	1.12
Quartile 2	1.26
Quartile 3	1.79

Comments

Calculation used

Q3.2B

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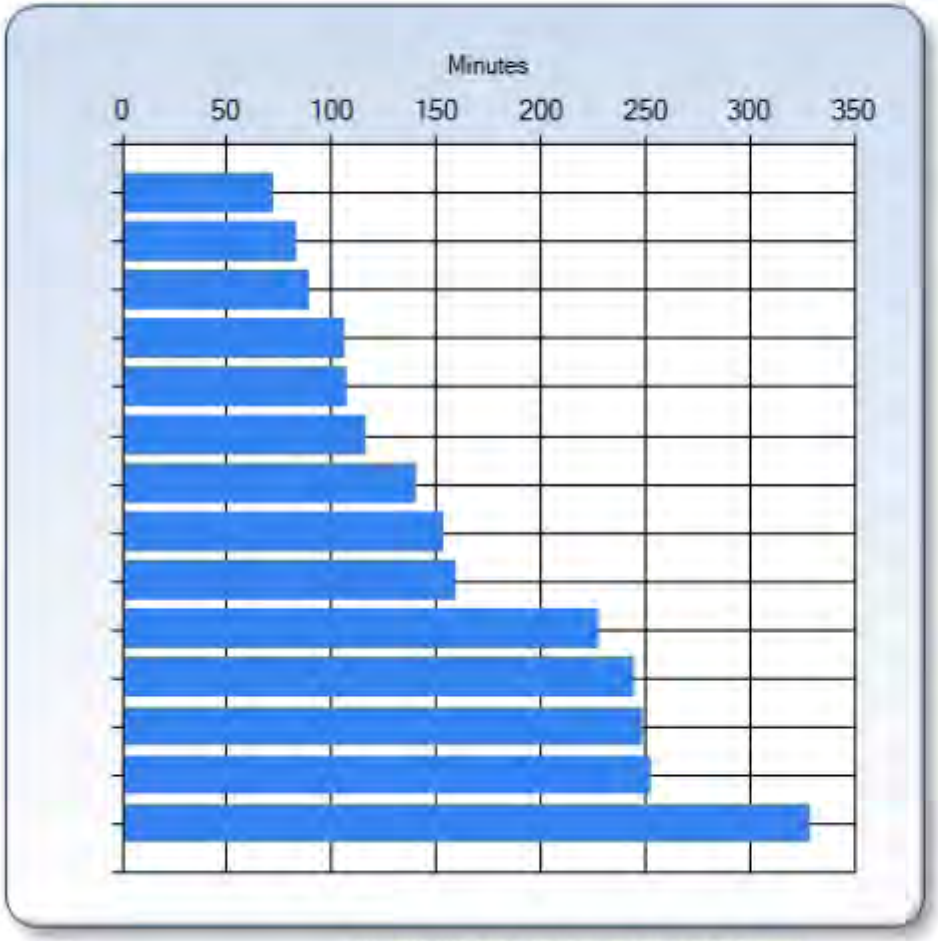
2| 2006YE CAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	167
Quartile 1	107
Quartile 2:	148
Quartile 3:	241

Comments

Calculation used

Q2.3A

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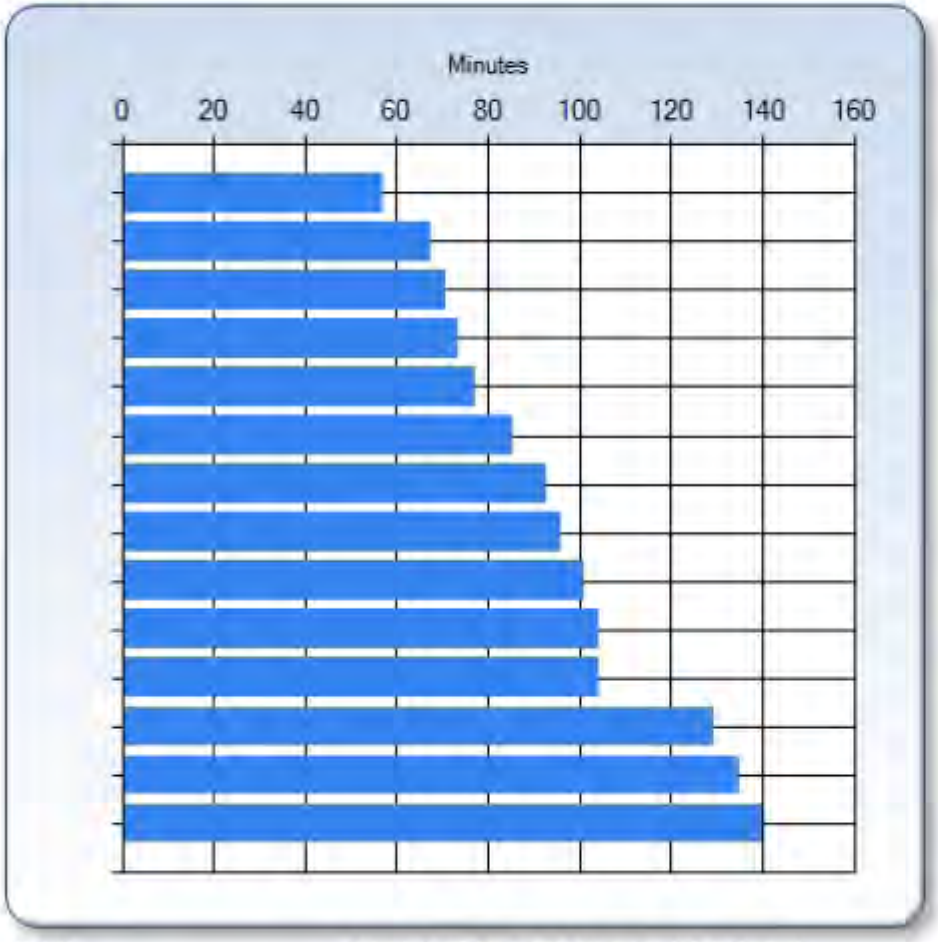
2| 2006YE CAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	95
Quartile 1	74
Quartile 2:	94
Quartile 3:	104

Comments

Calculation used

Q2.3B

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2| 2005YE CAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	151
Quartile 1	103
Quartile 2:	116
Quartile 3:	214

Comments

Calculation used

Q3.3A

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FIRST QUARTILE CONSULTING

2| 2005YE CAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	93
Quartile 1	77
Quartile 2:	89
Quartile 3:	104

Comments

Calculation used

Q3.3B

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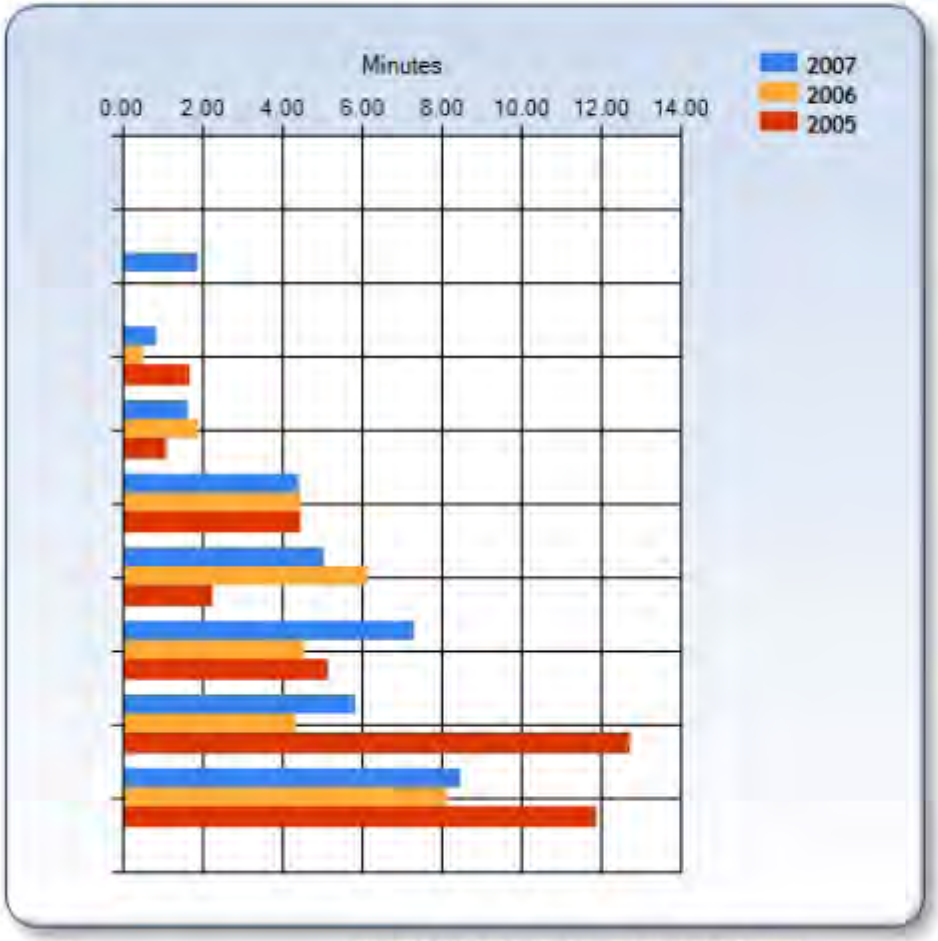
FIRST QUARTILE CONSULTING

1| 3-YEAR SUBSTATION CONTRIBUTION TO SAIDI: DISTRIBUTION SUBSTATIONS



Mean Quartile	
Mean	11.71
Quartile 1	3.14
Quartile 2:	13.41
Quartile 3:	17.14

Comments

Calculation used

Q1.2B, Q1.2D, Q1.2F

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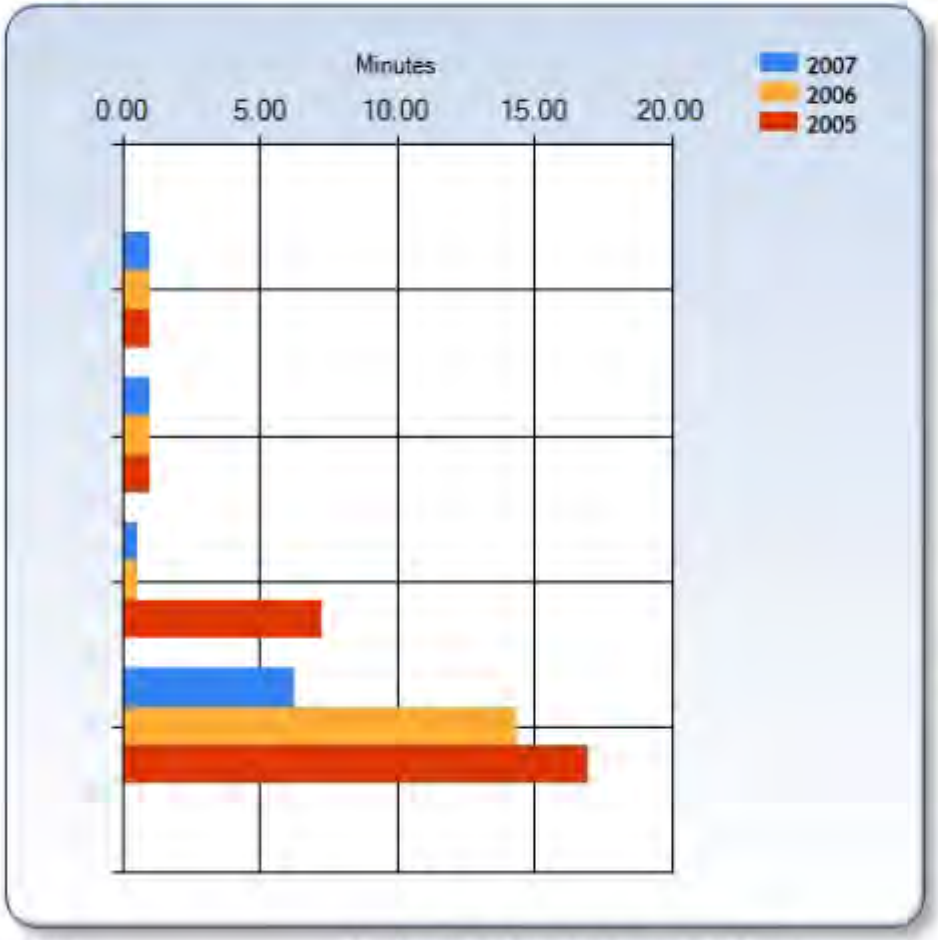
FIRST QUARTILE CONSULTING

1| 3-YEAR SUBSTATION CONTRIBUTION TO SAIDI: TRANSMISSION SUBSTATIONS



Mean Quartile	
Mean	13.03
Quartile 1	3.00
Quartile 2:	5.72
Quartile 3:	15.75

Comments

Calculation used

Q1.2A, Q1.2C, Q1.2E

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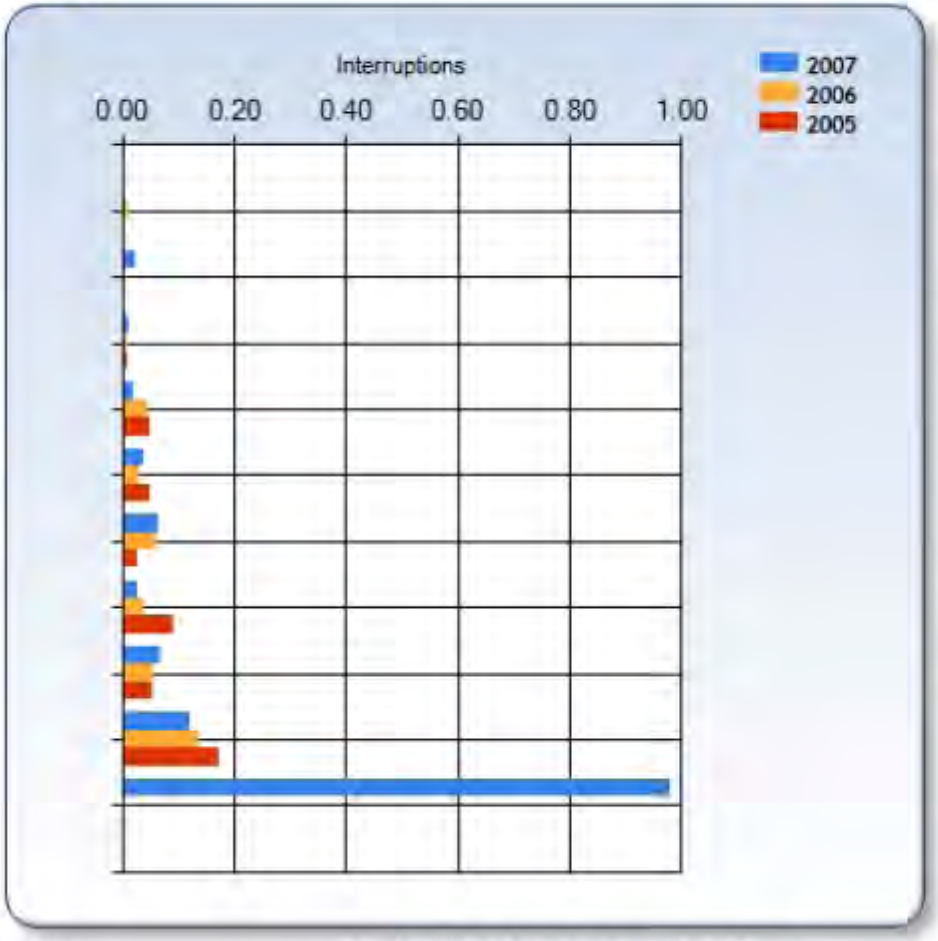
FIRST QUARTILE CONSULTING

1| 3-YEAR SUBSTATION CONTRIBUTION TO SAIFI: DISTRIBUTION SUBSTATIONS



Mean Quartile	
Mean	0.22
Quartile 1	0.05
Quartile 2:	0.14
Quartile 3:	0.17

Comments

Calculation used

Q1.1B, Q1.1D, Q1.1F

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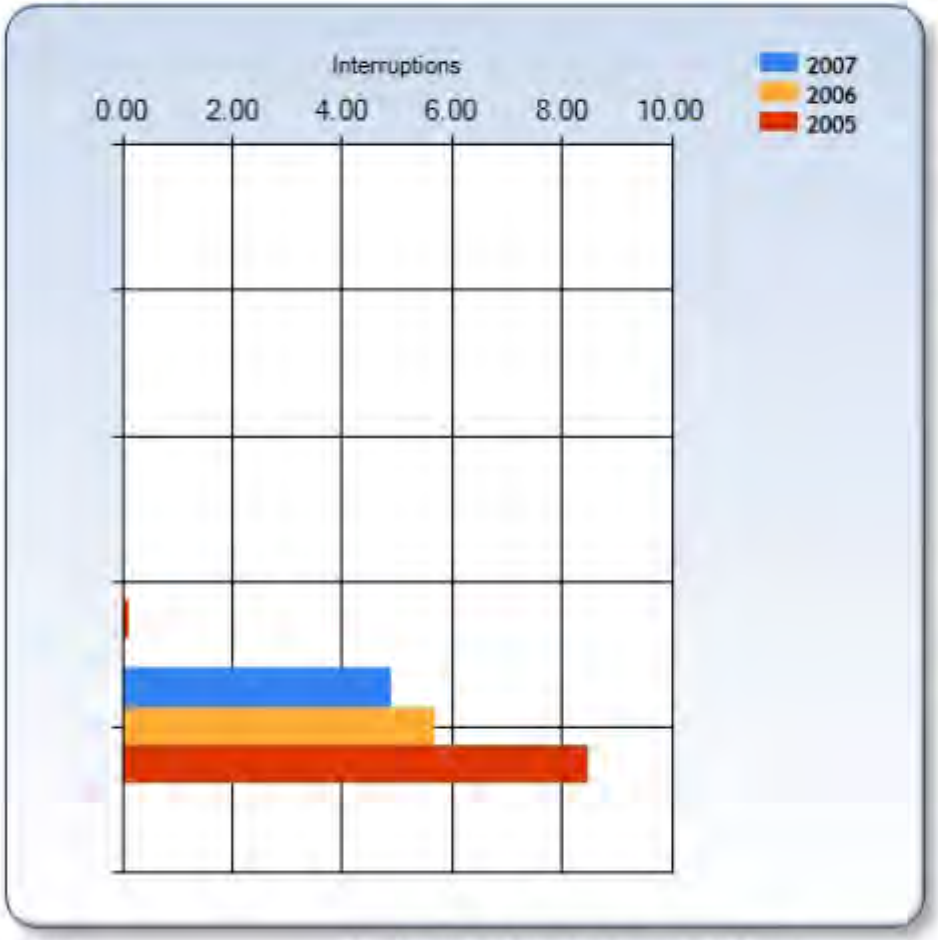
1| 3-YEAR SUBSTATION CONTRIBUTION TO SAIFI: TRANSMISSION SUBSTATIONS



Mean Quartile	
Mean	4.83
Quartile 1	0.03
Quartile 2:	0.09
Quartile 3:	4.89

Comments

Calculation used

Q1.1A, Q1.1C, Q1.1E

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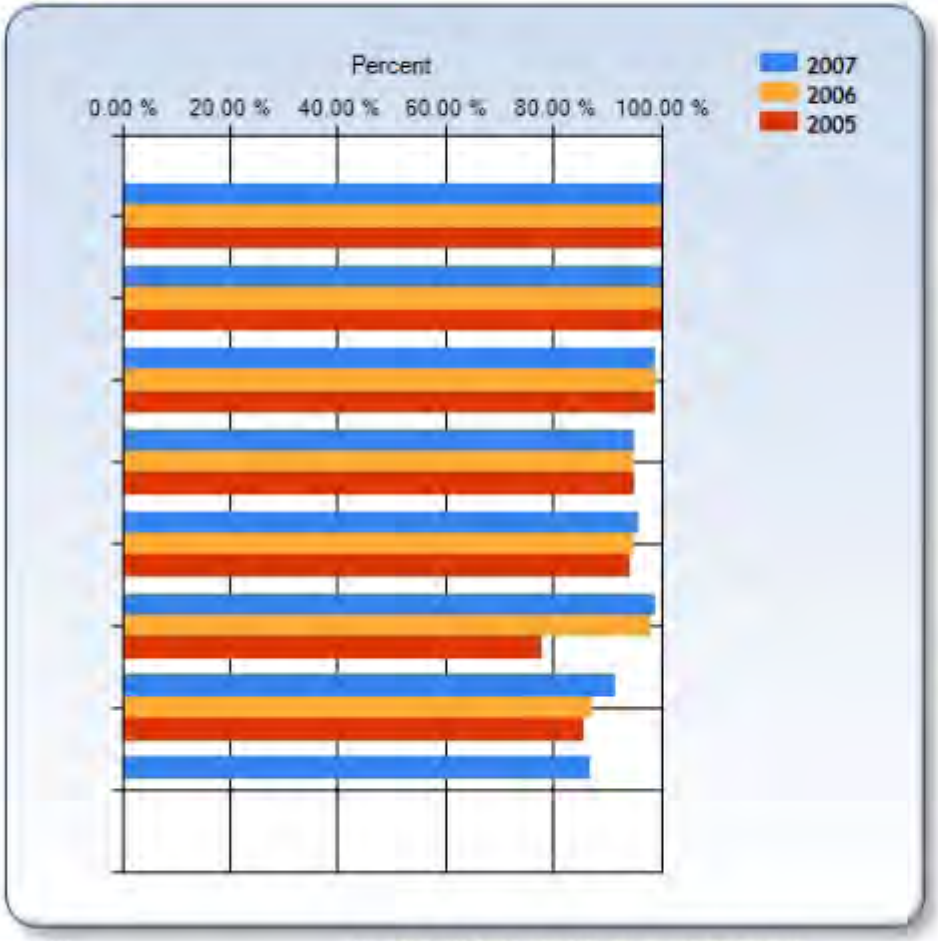
FIRST QUARTILE CONSULTING

3| 3-YEAR CORRECT OPERATIONS RATE [PERCENT OF TOTAL OPERATIONS] FOR RELAYS: TRANSMISSION SUBSTATIONS



Mean Quartile	
Mean	261.63 %
Quartile 1:	297.68 %
Quartile 2:	284.95 %
Quartile 3:	272.38 %

Comments

Calculation used

Q3.1A, Q3.2A, Q3.3A

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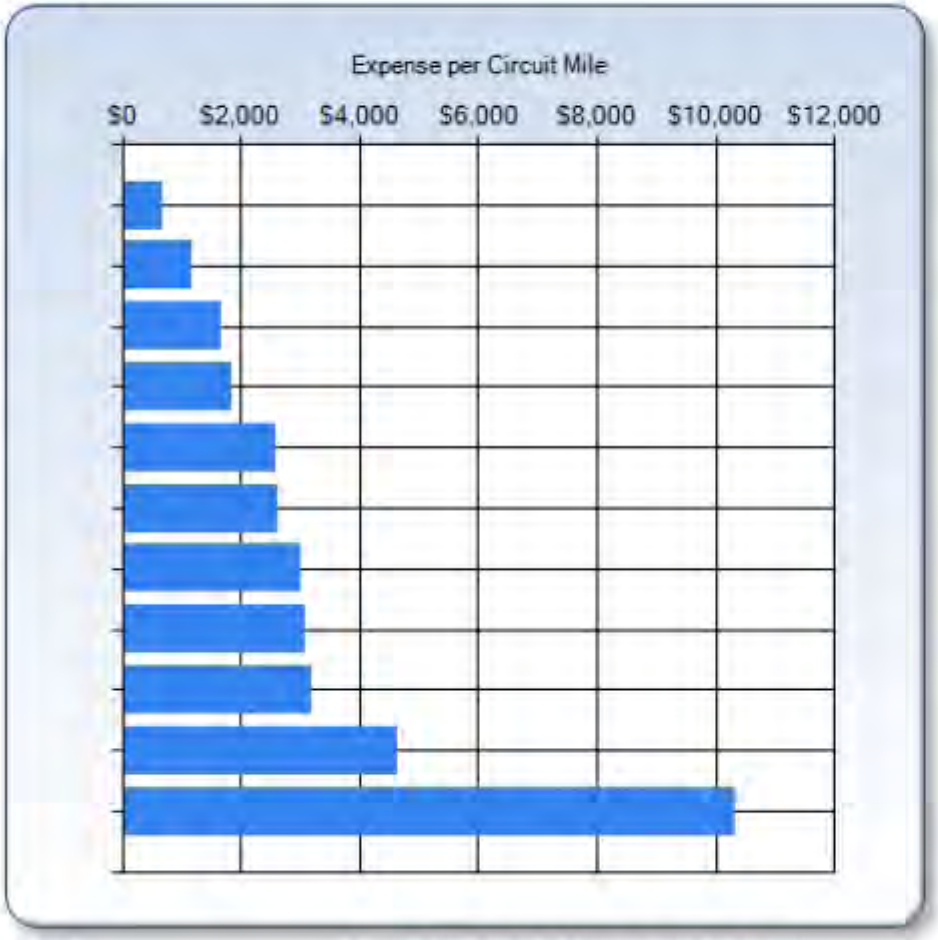
2005 DISTRIBUTION LINES O&M EXPENSE PER CIRCUIT MILE



Mean Quartile	
Mean	$3,170
Quartile 1	$1,765
Quartile 2:	$2,618
Quartile 3:	$3,152

Comments

Calculation used

Q5.8C / (Q9.2C + Q10.4C + Q10.5C)

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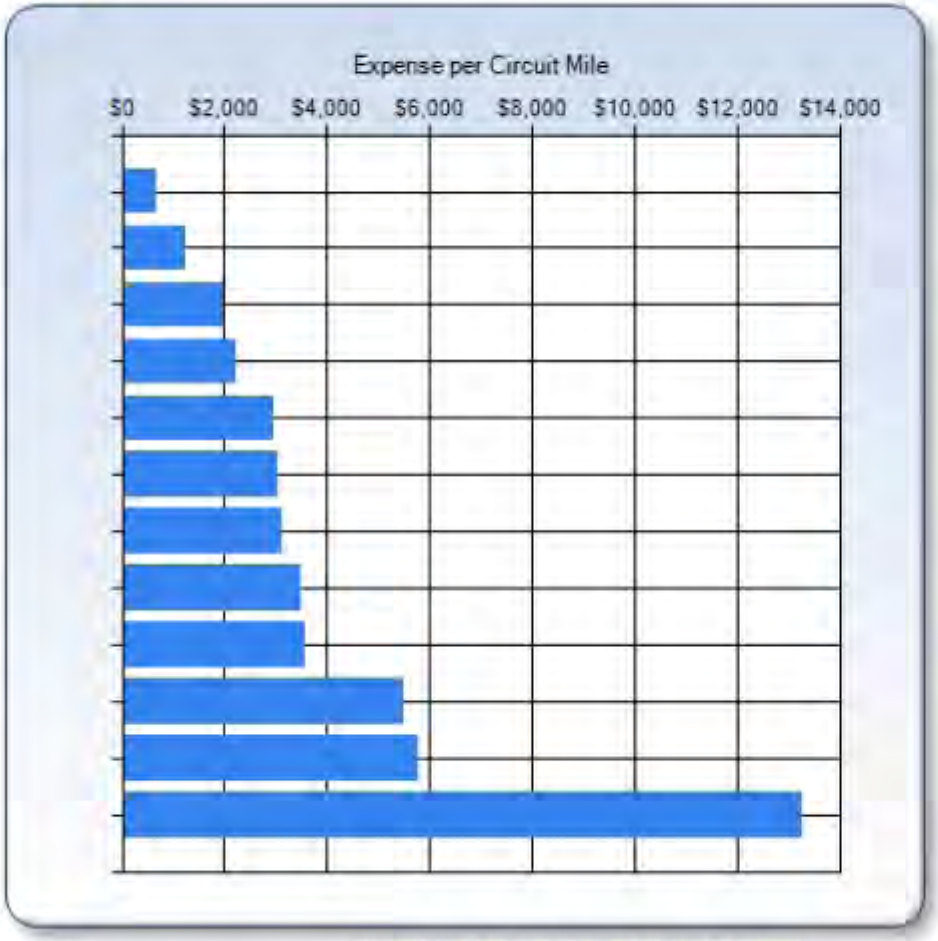
FIRST QUARTILE CONSULTING

2006 DISTRIBUTION LINES O&M EXPENSE PER CIRCUIT MILE



Mean Quartile	
Mean	$3,910
Quartile 1	$2,167
Quartile 2:	$3,084
Quartile 3:	$4,064

Comments

Calculation used

Q5.8B / (Q9.2B + Q10.4C + Q10.5B)

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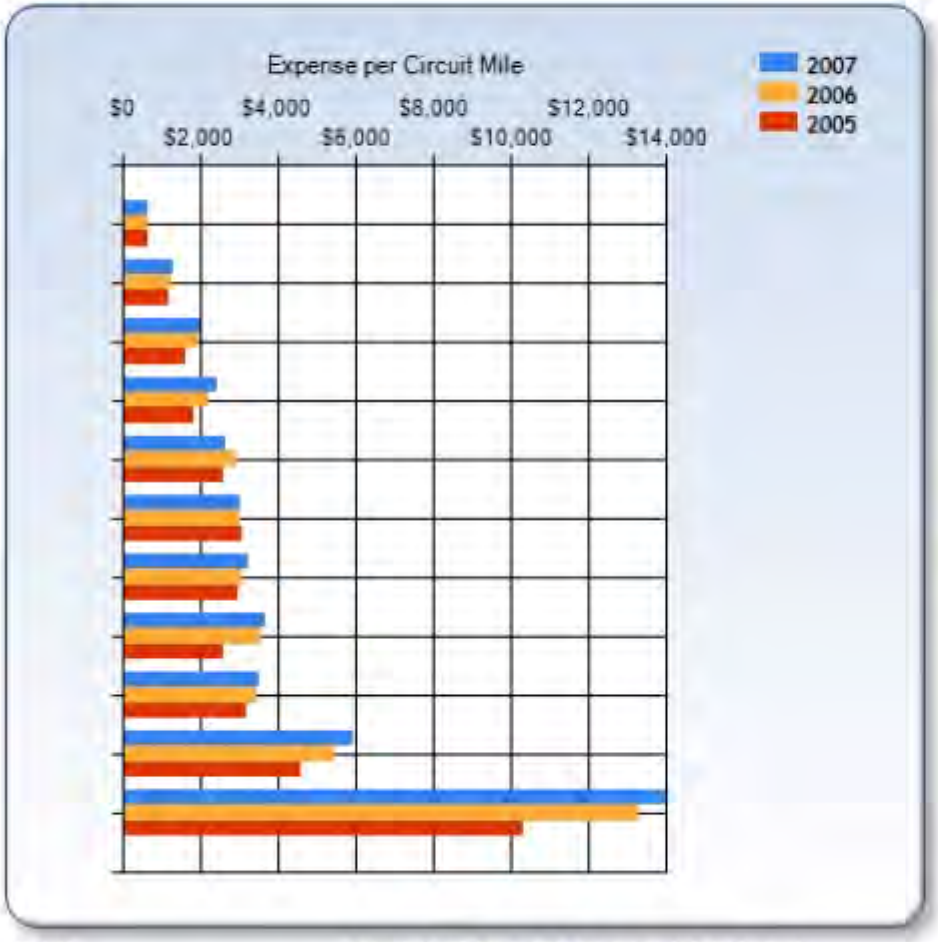
FIRST QUARTILE CONSULTING

3-YEAR DISTRIBUTION LINES O&M EXPENSE PER CIRCUIT MILE



Comments

Calculation used

Q5.8A / (Dist Circ Miles), Q5.8B / (Q9.2B + Q10.4C + Q10.5B), Q5.8C / (Q9.2C + Q10.4C + Q10.5C)

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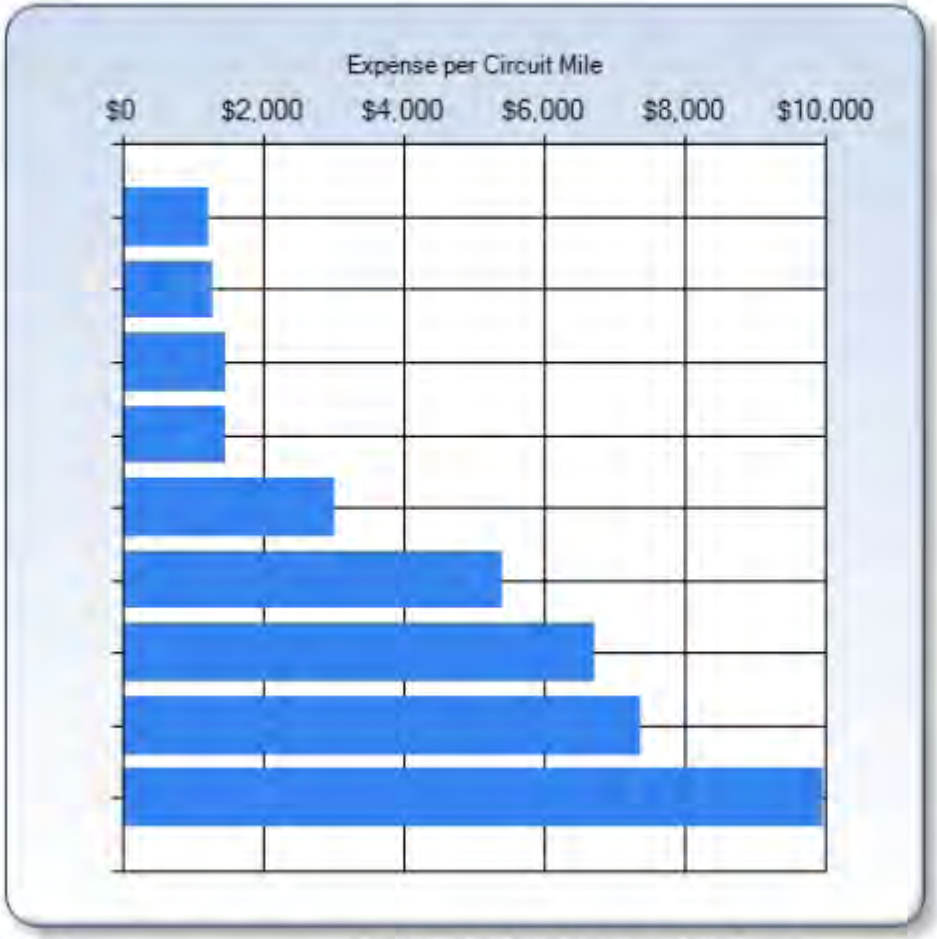
2005YE TRANSMISSION LINES O&M EXPENSE PER CIRCUIT MILE



Mean Quartile	
Mean	$4,226
Quartile 1	$1,475
Quartile 2:	$3,041
Quartile 3:	$6,731

Comments

Calculation used

Q7.8C / Q22.2B

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FIRST QUARTILE CONSULTING

2006YE TRANSMISSION LINES O&M EXPENSE PER CIRCUIT MILE



Mean Quartile	
Mean	5,524 %
Quartile 1	1,664 %
Quartile 2:	3,189 %
Quartile 3:	9,241 %

Comments

Calculation used

Q7.8B / Q22.1B

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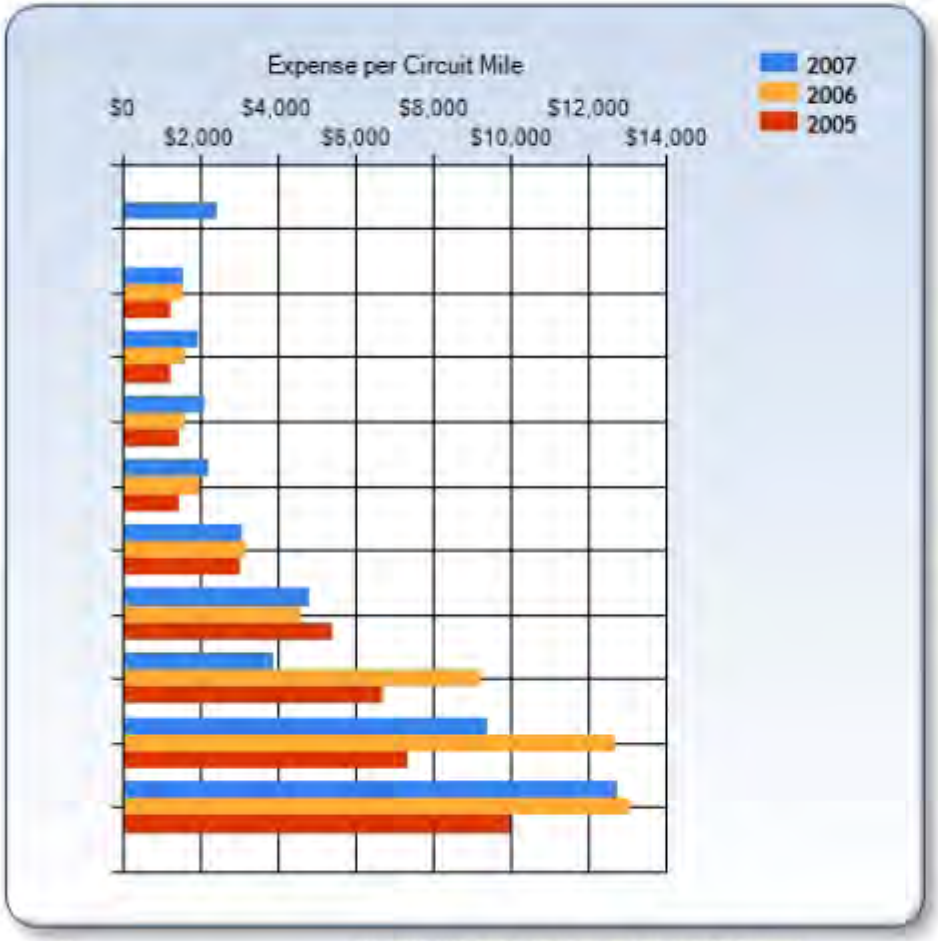
3-YEAR TRANSMISSION LINES O&M EXPENSE PER CIRCUIT MILE



Comments

Calculation used

(Trans Lines O&M) / (Trans Circ Mile), Q7.8B / Q22.1B, Q7.8C / Q22.2B

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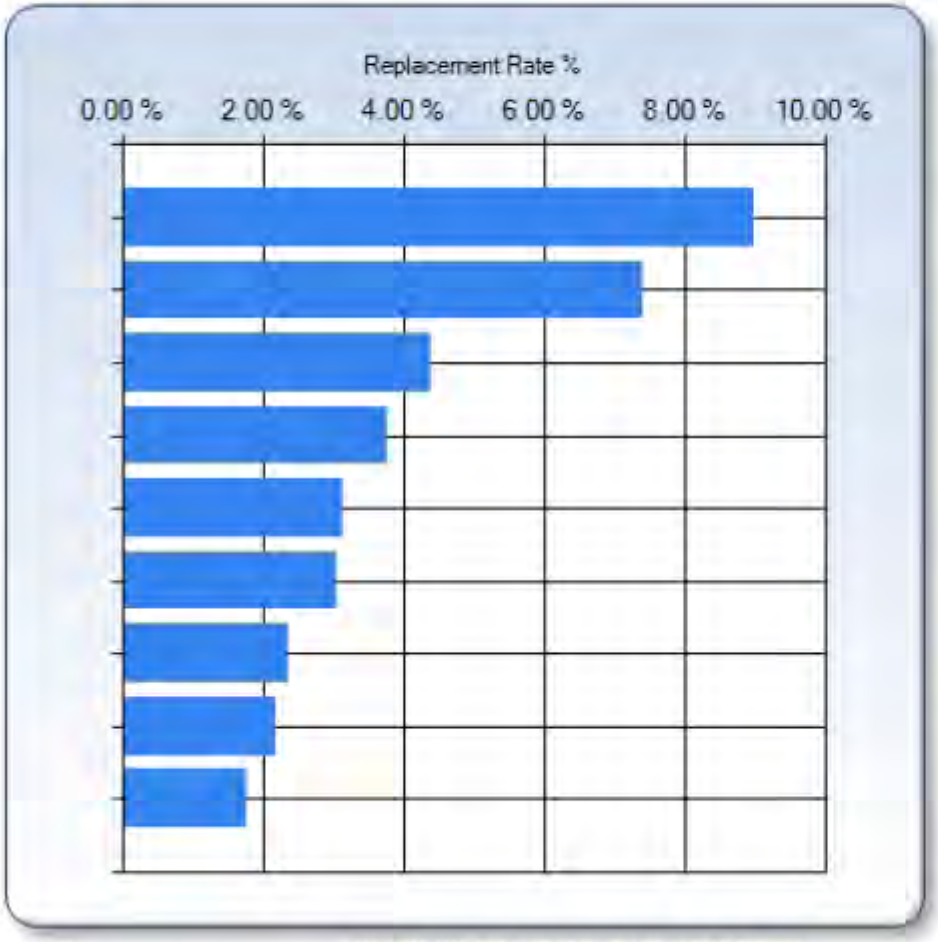
FIRST QUARTILE CONSULTING

3-YR TRANSMISSION LINE CAPITAL SPENDING LESS NEW TRANSMISSION LINES PER ASSET



Mean Quartile	
Mean	4.13 %
Quartile 1	4.41 %
Quartile 2	3.15 %
Quartile 3	2.37 %

Comments

Calculation used

(((((Trans Lines Capital) - Q11.1A) / Q16.4A) + ((Q3.7B - Q11.1B) / Q16.4B) + ((Q3.7C - Q11.1C) / Q16.4C)) / 3) * 100

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FIRST QUARTILE CONSULTING

3-YEAR DISTRIBUTION SUBSTATION CAPITAL SPENDING PER ASSET



Mean Quartile	
Mean	43 %
Quartile 1	19 %
Quartile 2:	16 %
Quartile 3:	10 %

Comments

Calculation used

(Q2.6A) / (Q16.2A) * 100, Q2.6B / Q16.2B * 100, Q2.6C / Q16.2C * 100

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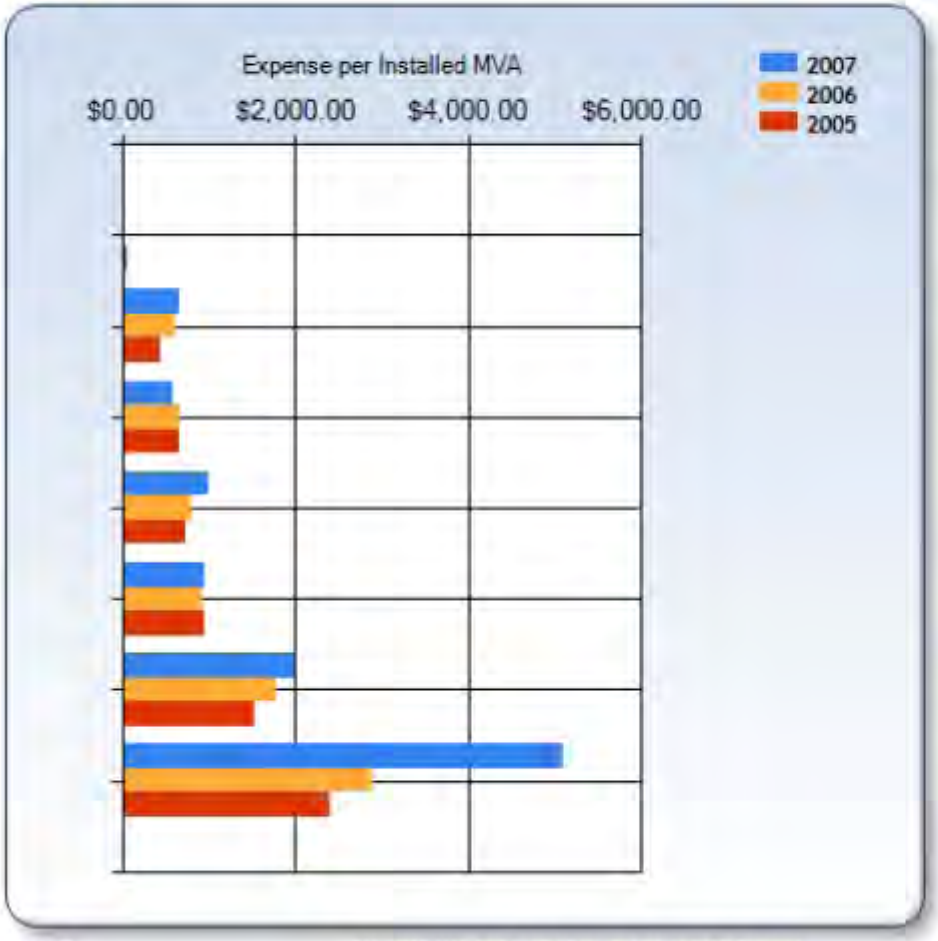
FIRST QUARTILE CONSULTING

3-YEAR DISTRIBUTION SUBSTATION O&M EXPENSE PER INSTALLED MVA



Mean Quartile	
Mean	$3,557.712
Quartile 1	$1,818.769
Quartile 2:	$2,561.569
Quartile 3:	$4,075.165

Comments

Calculation used

Q6.5A / Q18.1A, Q6.5B / Q18.1B, Q6.5C / Q18.1C

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FIRST QUARTILE CONSULTING

2005 DISTRIBUTION SUBSTATION CAPITAL SPENDING PER ASSET



Mean Quartile	
Mean	14 %
Quartile 1	7 %
Quartile 2:	6 %
Quartile 3:	4 %

Comments

Calculation used

Q2.6C / Q16.2C * 100

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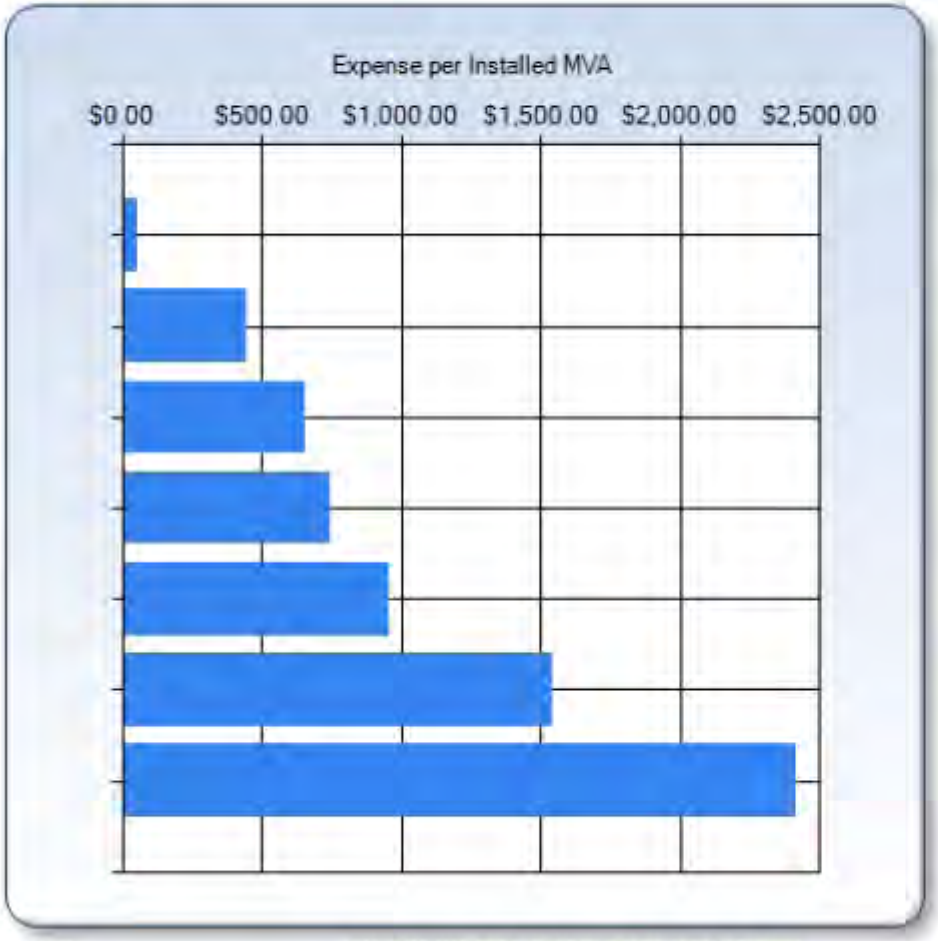
2005 DISTRIBUTION SUBSTATION O&M EXPENSE PER INSTALLED MVA



Mean Quartile	
Mean	$975.174
Quartile 1	$553.656
Quartile 2:	$745.402
Quartile 3:	$1,249.770

Comments

Calculation used

Q6.5C / Q18.1C

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FIRST QUARTILE CONSULTING

2006 DISTRIBUTION SUBSTATION CAPITAL SPENDING PER ASSET



Mean Quartile	
Mean	15 %
Quartile 1	6 %
Quartile 2:	5 %
Quartile 3:	3 %

Comments

Calculation used

Q2.6B / Q16.2B * 100

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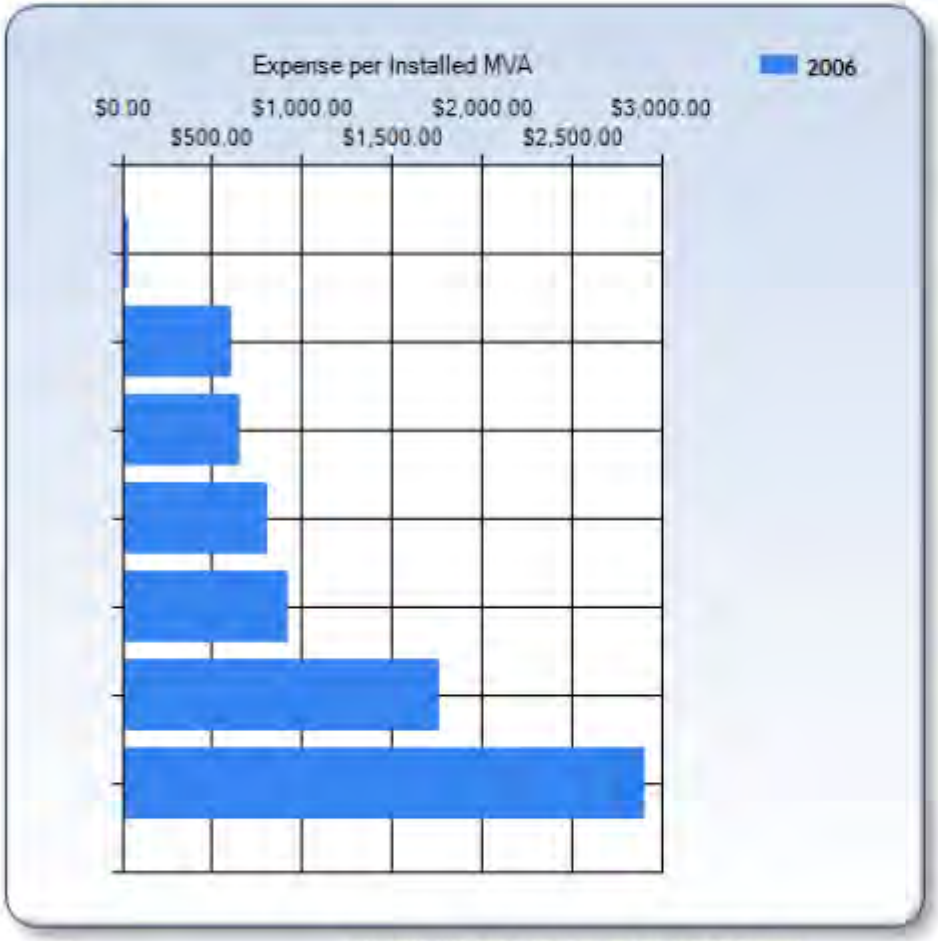
FIRST QUARTILE CONSULTING

2006 DISTRIBUTION SUBSTATION O&M EXPENSE PER INSTALLED MVA



Mean Quartile	
Mean	$1,103.659
Quartile 1	$633.863
Quartile 2:	$810.341
Quartile 3:	$1,349.366

Comments

Calculation used

Q6.5B / Q18.1B

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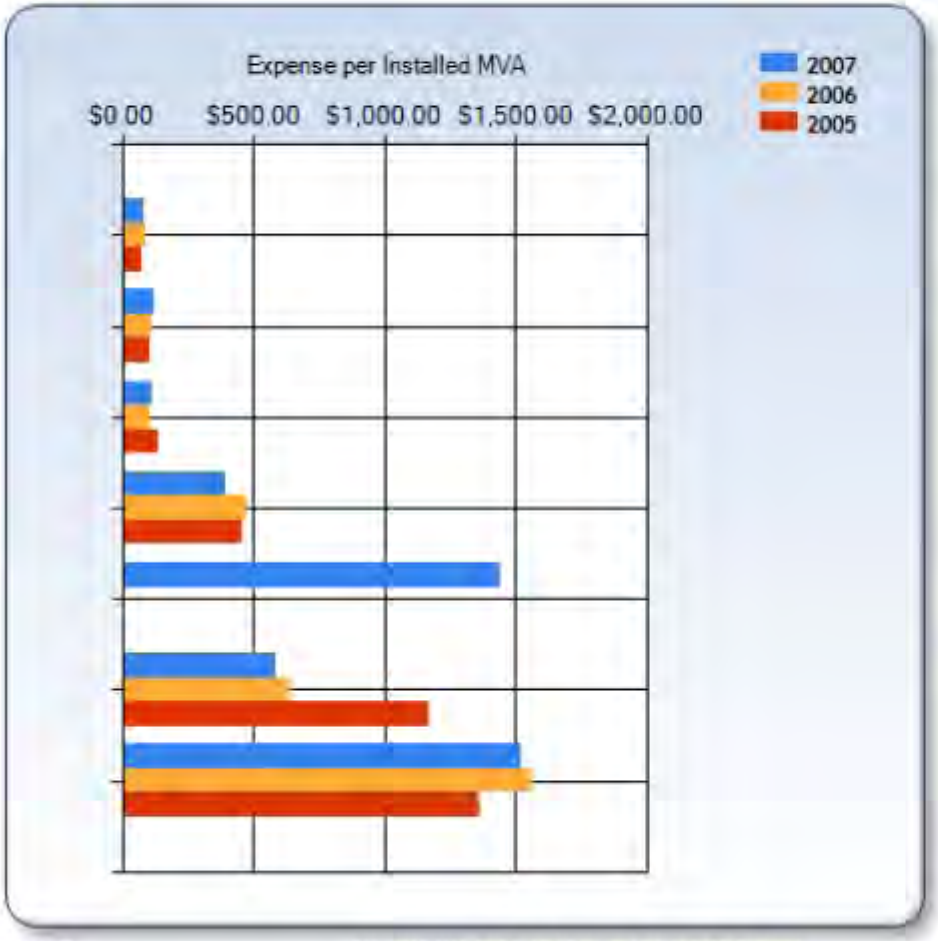
3-YEAR TRANSMISSION SUBSTATION O&M EXPENSE PER INSTALLED MVA



Mean Quartile	
Mean	$1,515.342
Quartile 1	$361.468
Quartile 2:	$1,334.957
Quartile 3:	$1,925.466

Comments

Calculation used

Q6a.5A / Q19.1A, Q6a.5B / Q19.1B, Q6a.5C / Q19.1C

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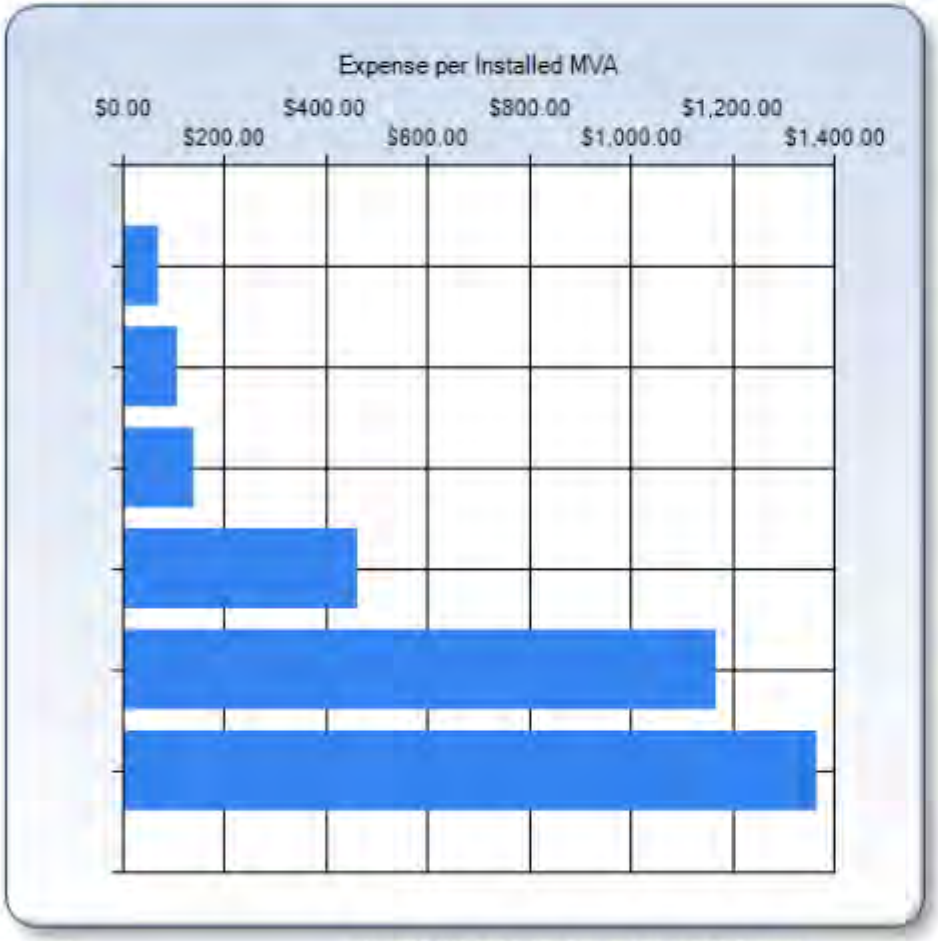
2005 TRANSMISSION SUBSTATION O&M EXPENSE PER INSTALLED MVA



Mean Quartile	
Mean	$553.246
Quartile 1	$117.309
Quartile 2:	$301.144
Quartile 3:	$991.821

Comments

Calculation used

Q6a.5C / Q19.1C

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2006 TRANSMISSION SUBSTATION O&M EXPENSE PER INSTALLED MVA



Mean Quartile	
Mean	$501.283
Quartile 1	$112.075
Quartile 2:	$296.805
Quartile 3:	$603.668

Comments

Calculation used

Q6a.5B / Q19.1B

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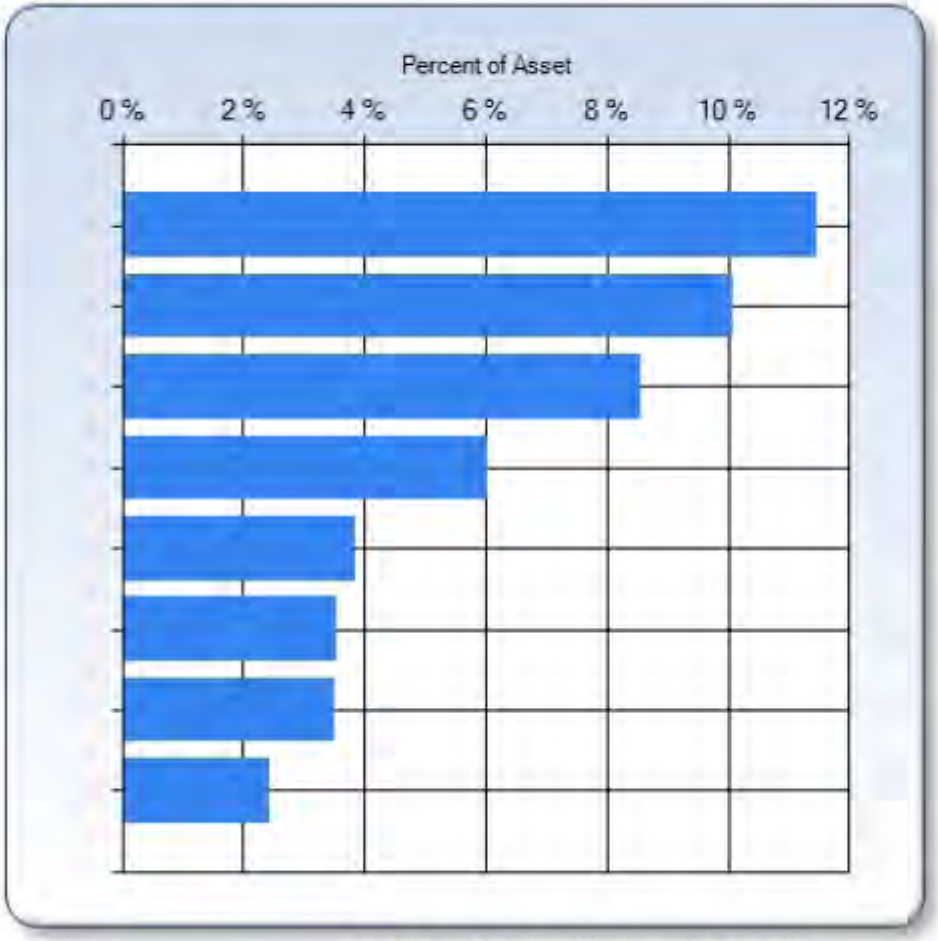
FIRST QUARTILE CONSULTING

2005 TRANSMISSION SUBSTATION CAPITAL SPENDING PER ASSET



Mean Quartile	
Mean	6 %
Quartile 1:	9 %
Quartile 2:	5 %
Quartile 3:	4 %

Comments

Calculation used

Q2a.6C / Q16.3C * 100

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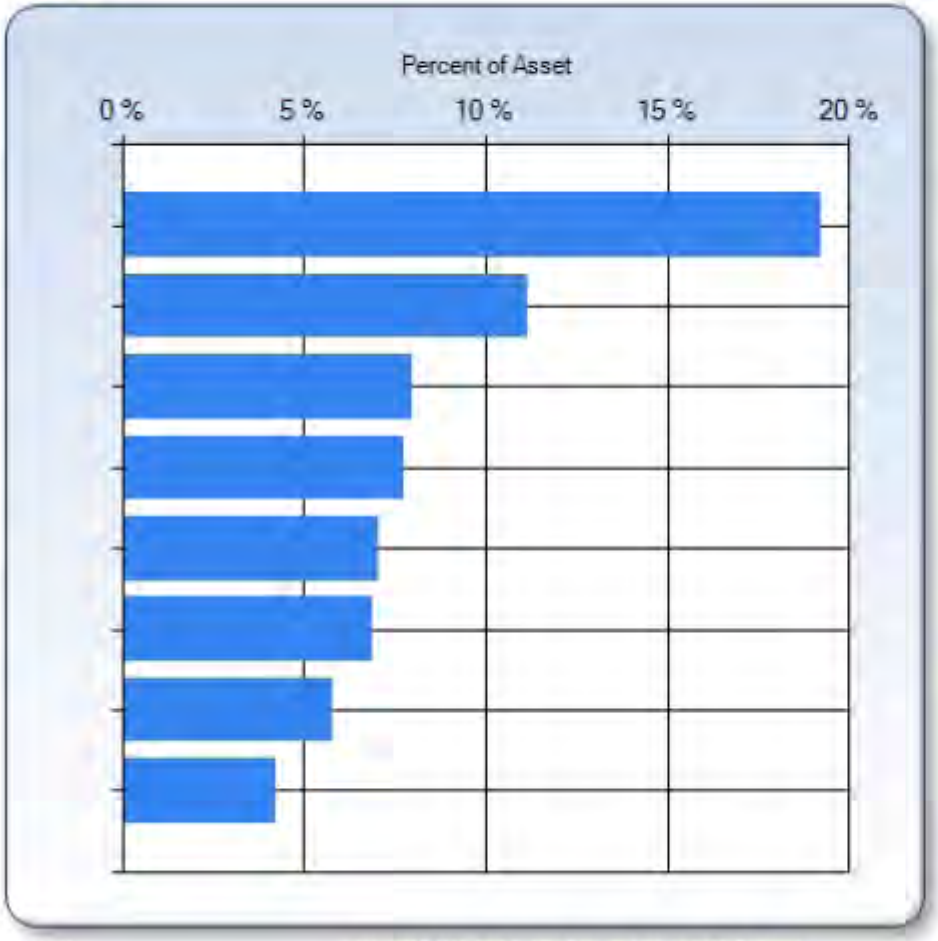
2006 TRANSMISSION SUBSTATION CAPITAL SPENDING PER ASSET



Mean Quartile	
Mean	9 %
Quartile 1	9 %
Quartile 2:	7 %
Quartile 3:	7 %

Comments

Calculation used

Q2a.6B / Q16.3B * 100

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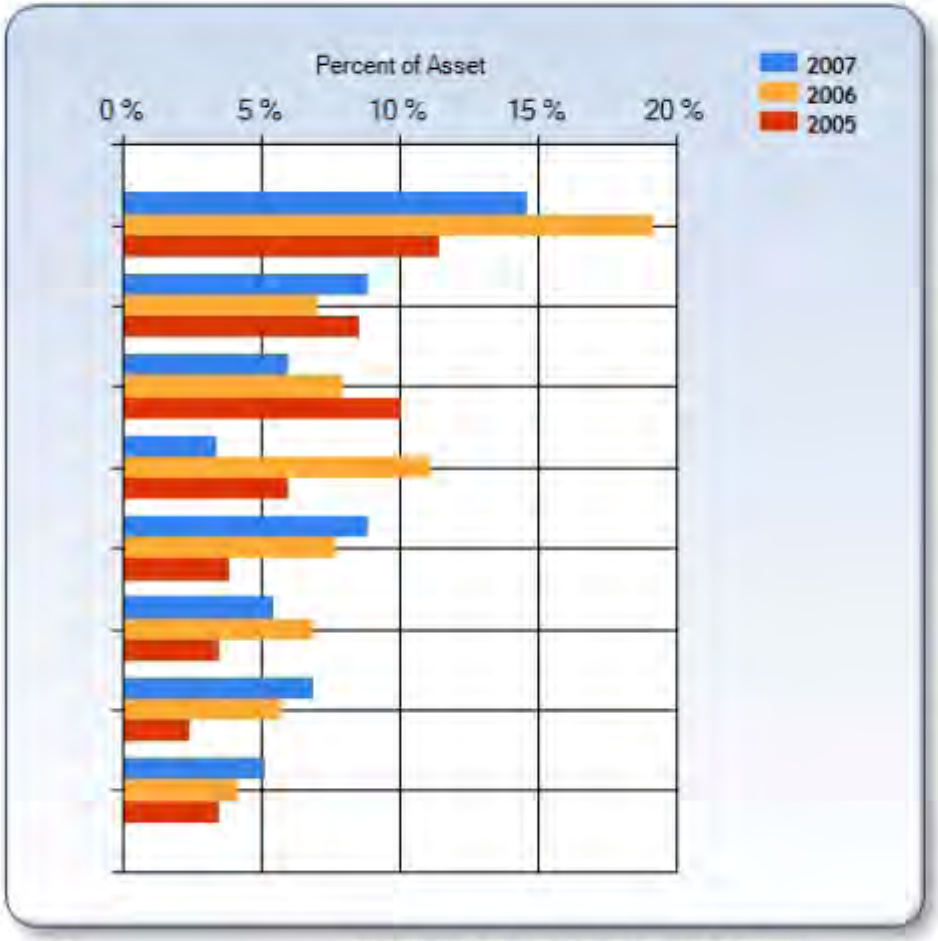
FIRST QUARTILE CONSULTING

3-YEAR TRANSMISSION SUBSTATION CAPITAL SPENDING PER ASSET



Mean Quartile	
Mean	22 %
Quartile 1	24 %
Quartile 2:	21 %
Quartile 3:	16 %

Comments

Calculation used

(Q2a.6A) / (Q16.3A) * 100, Q2a.6B / Q16.3B * 100, Q2a.6C / Q16.3C * 100

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3-YEAR DISTRIBUTION SUBSTATION O&M EXPENSE PER ASSET



Mean Quartile	
Mean	$0.164
Quartile 1	$0.070
Quartile 2:	$0.089
Quartile 3:	$0.113

Comments

Calculation used

Q6.5A / Q16.2A, Q6.5B / Q16.2B, Q6.5C / Q16.2C

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3-YEAR TRANSMISSION SUBSTATION O&M EXPENSE PER ASSET



Mean Quartile	
Mean	$0.049
Quartile 1	$0.023
Quartile 2:	$0.043
Quartile 3:	$0.070

Comments

Calculation used

Q6a.5A / Q16.3A, Q6a.5B / Q16.3B, Q6a.5C / Q16.3C

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1| SAIDI (Excluding Major Events using 2.5 beta method)
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5| Interruptions by cause per circuit mile
5| SAIFI interruptions by cause per circuit

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6| Percent of circuits repeated in the bottom 10% last year - using SAIDI criteria

6a| Percent of circuits repeated in the bottom 10% last year - using SAIFI criteria

7| Average SAIDI for the worst 10% of circuits last year

7| Average SAIFI for the worst 10% of circuits last year

8| Percent of customers in each category - by number of interruptions last year

8| Percent of customers with <3 interruptions last year

9| Maximum number of seconds for an outage to be classified as momentary

10| Major events experienced the last three years

11| Please describe any effective strategies used to improve the effectiveness of the outage management system?

12| Please describe any effective strategies used to improve the effectiveness of dispatching to reduce outage durations?

13| What major challenges are being encountered – near-term and long-term – that are causing new behaviors/strategies?

14| How do you manage tradeoffs between cost and reliability?

15| Please describe any successful initiatives used to improve worst circuit performance?

16| What was the most important initiative taken to improve SAIDI?

17| What was the most important initiative taken to improve SAIFI?

18| What was the most important initiative taken to improve CAIDI?

19| Please describe any successful staffing practices used during off-hours to reduce duration of outages?

20| Under what conditions do you provide estimated restoration times?

21| What method is used to estimate restoration times?

22| What strategies are used to minimize scheduled interruptions? [e.g. mobile generators]

23| Average cost of an interruption [not including fines or penalties]: Cost to Correct

23| Average cost of an interruption [not including fines or penalties]: Cost to Prevent

5| Customer minutes of interruption by cause per circuit mile (excluding events)

5| Interruptions by cause per circuit mile (excluding events)

5| SAIDI Equipment Failures percent of minutes

5| SAIDI Percent of minutes by cause

5| SAIFI equipment failure percent of outages

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5| SAIFI statistics percent of outages by cause

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1| SAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	275
Quartile 1	126
Quartile 2:	239
Quartile 3:	331

Comments

Calculation used

Q1.1A

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1| SAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	135
Quartile 1	86
Quartile 2:	108
Quartile 3:	142

Comments

Calculation used

Q1.1B

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1| SAIDI (EXCLUDING MAJOR EVENTS)



Mean Quartile	
Mean	167
Quartile 1	89
Quartile 2:	135
Quartile 3:	194

Comments

Calculation used

Q1.1C

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1| SAIDI (EXCLUDING TRANSMISSION & GENERATION OUTAGES)



Mean Quartile	
Mean	241
Quartile 1	98
Quartile 2:	203
Quartile 3:	300

Comments

Calculation used

Q1.1D

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1| SAIDI (EXCLUDING MAJOR EVENTS USING 2.5 BETA METHOD)



Mean Quartile	
Mean	134
Quartile 1	88
Quartile 2:	110
Quartile 3:	199

Comments

Calculation used

Q1.1E

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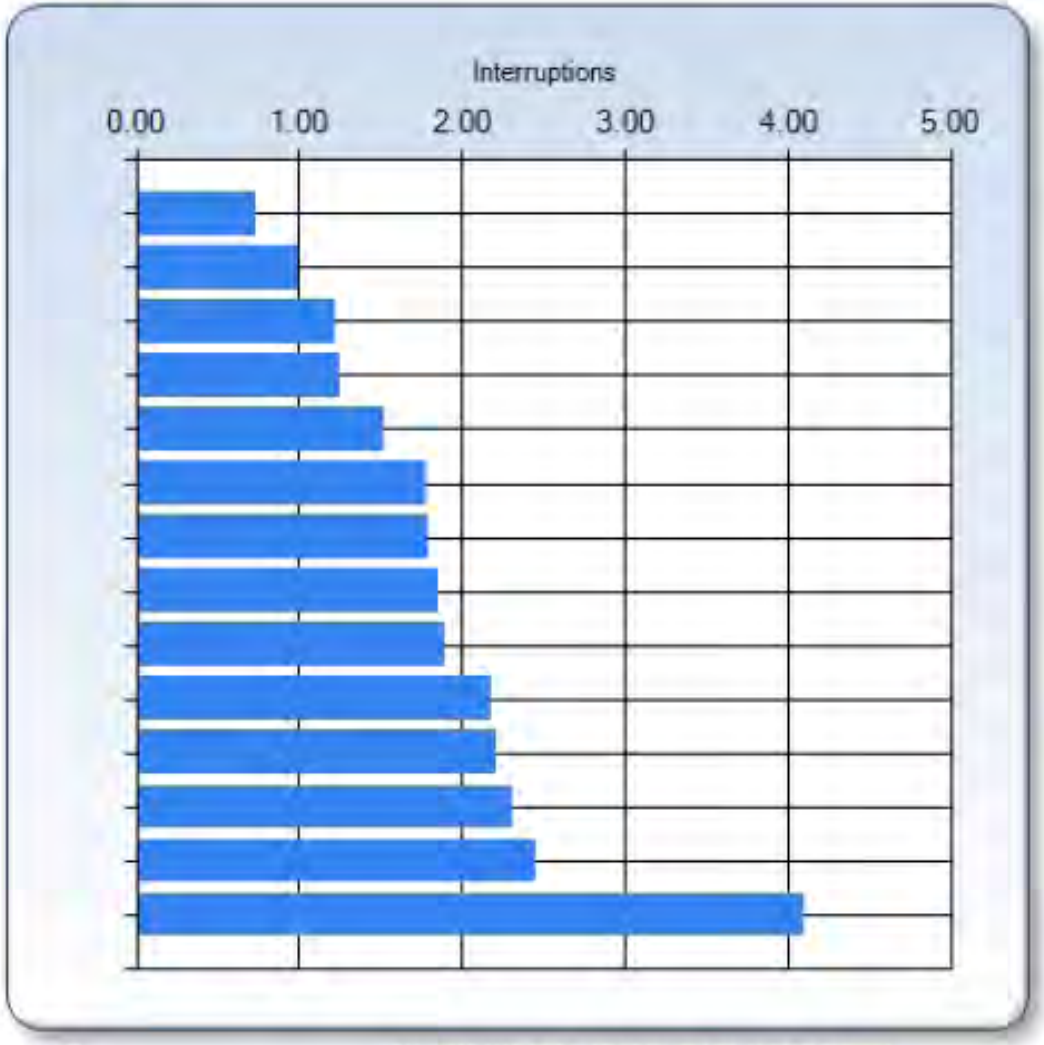
1| SAIFI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1.88
Quartile 1	1.32
Quartile 2:	1.83
Quartile 3:	2.21

Comments

Calculation used

Q1.2A

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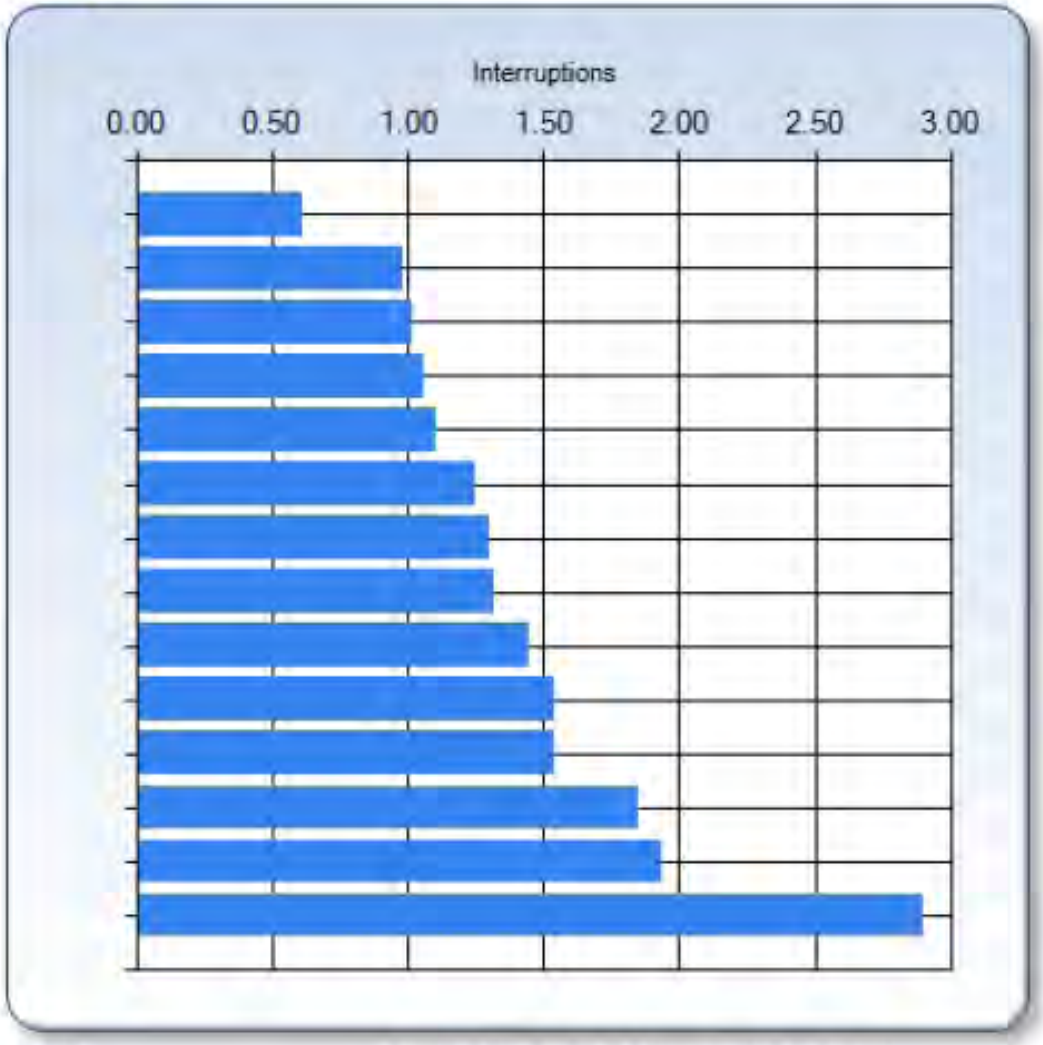
1| SAIFI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1.42
Quartile 1	1.07
Quartile 2:	1.31
Quartile 3:	1.54

Comments

Calculation used

Q1.2B

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1| SAIFI (EXCLUDING MAJOR EVENTS)



Mean Quartile	
Mean	1.68
Quartile 1	1.31
Quartile 2:	1.55
Quartile 3:	1.88

Comments

Calculation used

Q1.2C

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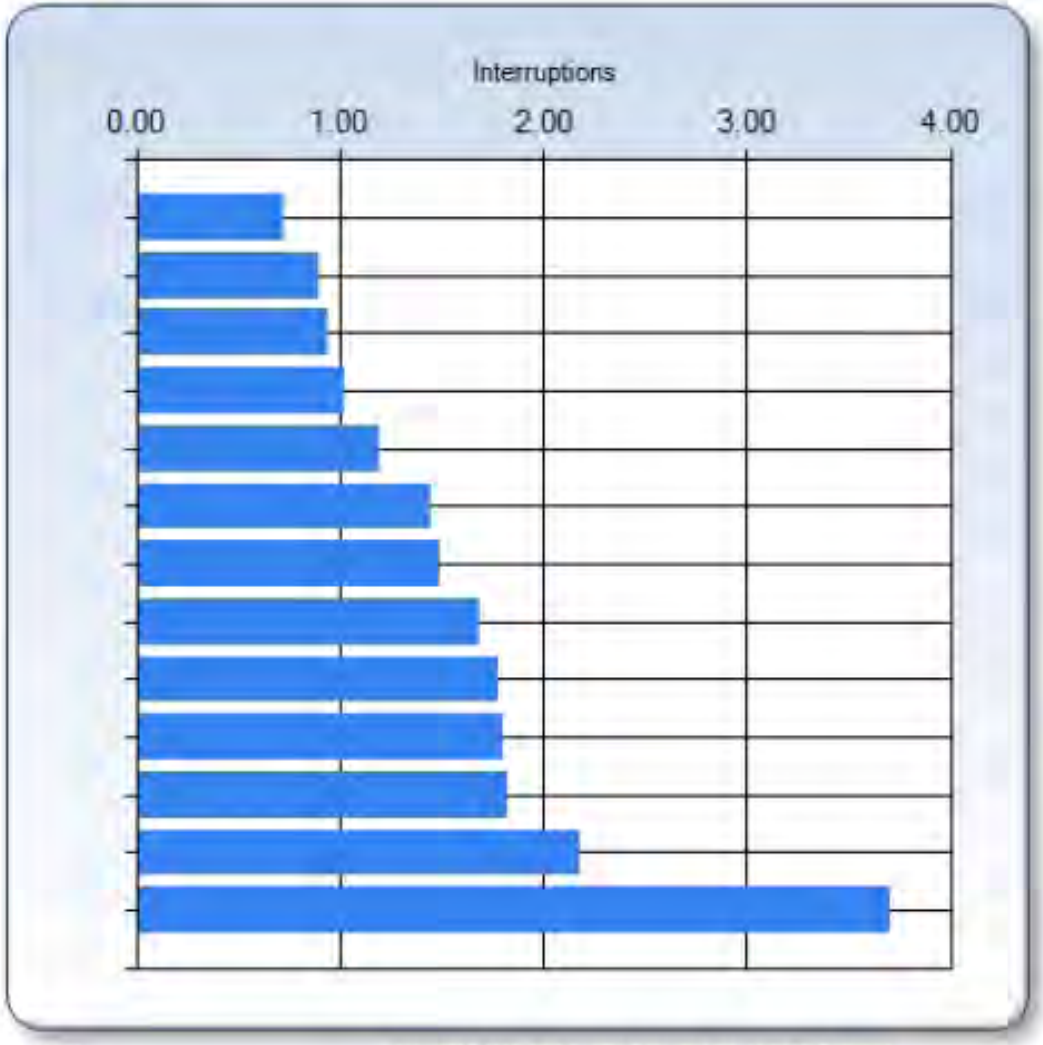
1| SAIFI (EXCLUDING TRANSMISSION OR GENERATION EVENTS)



Mean Quartile	
Mean	1.59
Quartile 1	1.03
Quartile 2:	1.50
Quartile 3:	1.80

Comments

Calculation used

Q1.2D

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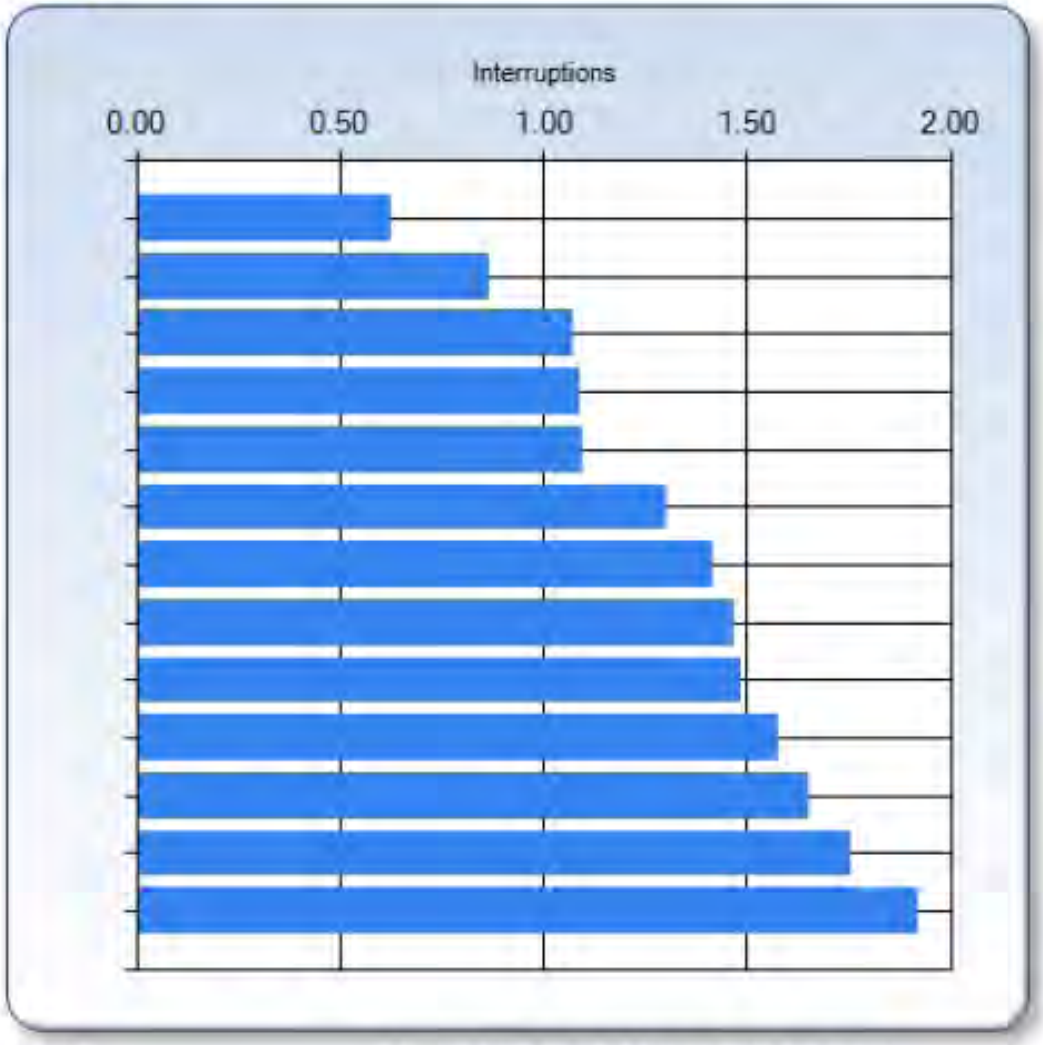
1| SAIFI (EXCLUDING MAJOR EVENTS USING 2.5 BETA METHOD)



Mean Quartile	
Mean	1.33
Quartile 1	1.09
Quartile 2:	1.42
Quartile 3:	1.58

Comments

Calculation used

Q1.2E

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1| CAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	140
Quartile 1	106
Quartile 2:	124
Quartile 3:	177

Comments

Calculation used

Q1.3A

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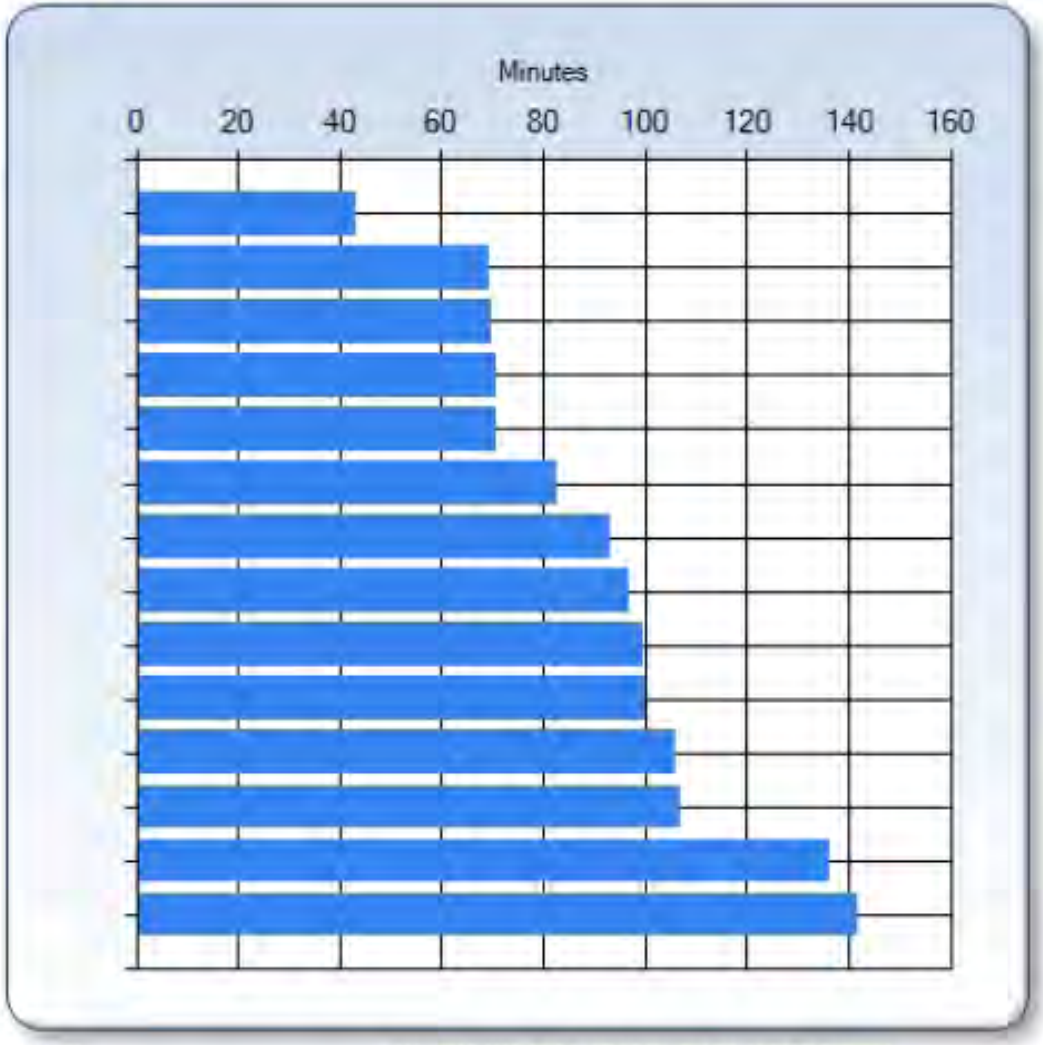
1| CAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	92
Quartile 1	71
Quartile 2:	95
Quartile 3:	105

Comments

Calculation used

Q1.3B

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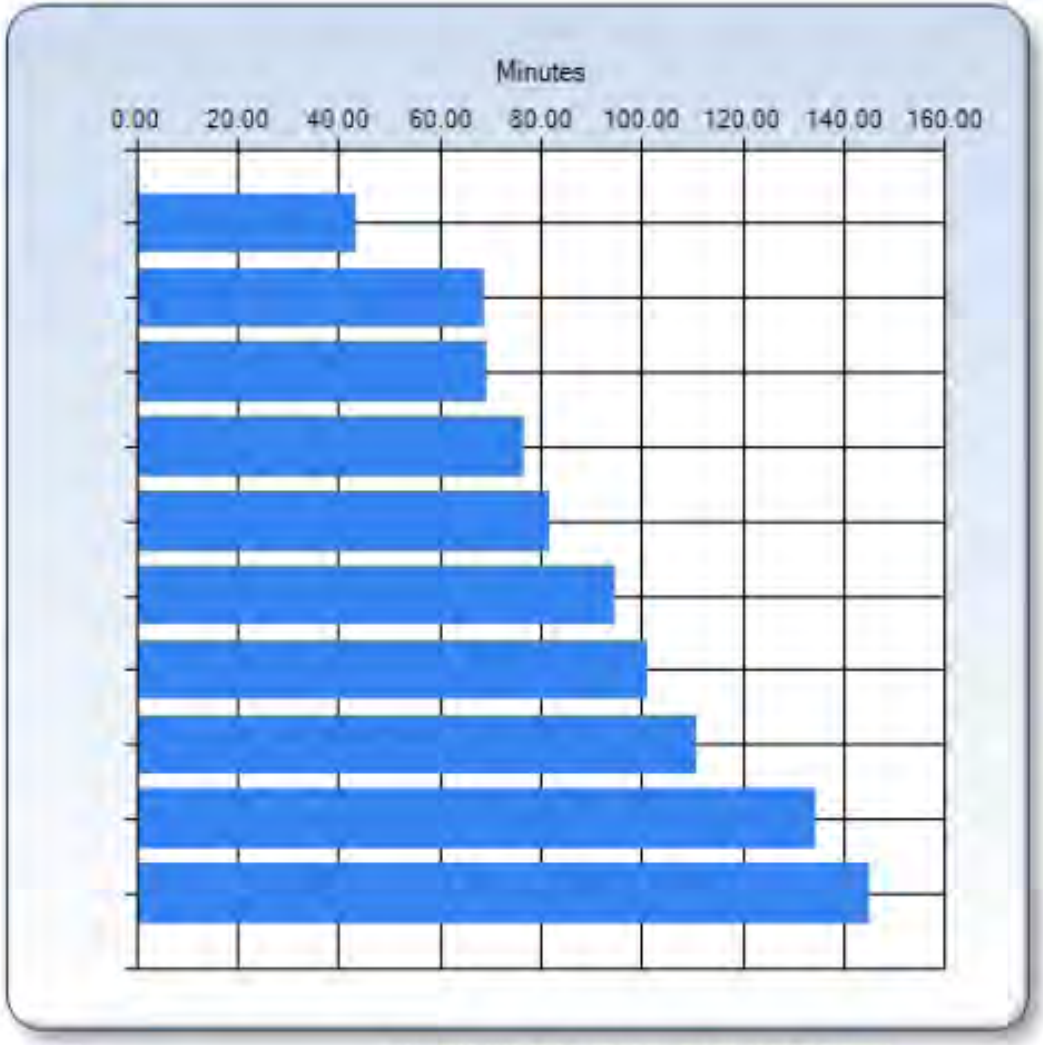
1| CAIDI (EXCLUDING MAJOR EVENTS)



Mean Quartile	
Mean	92.80
Quartile 1	71.30
Quartile 2:	88.49
Quartile 3:	108.58

Comments

Calculation used

Q1.3C

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1| CAIDI (EXCLUDING TRANSMISSION OR GENERATION EVENTS)



Mean Quartile	
Mean	145.06
Quartile 1	85.65
Quartile 2:	134.00
Quartile 3:	200.00

Comments

Calculation used

Q1.3D

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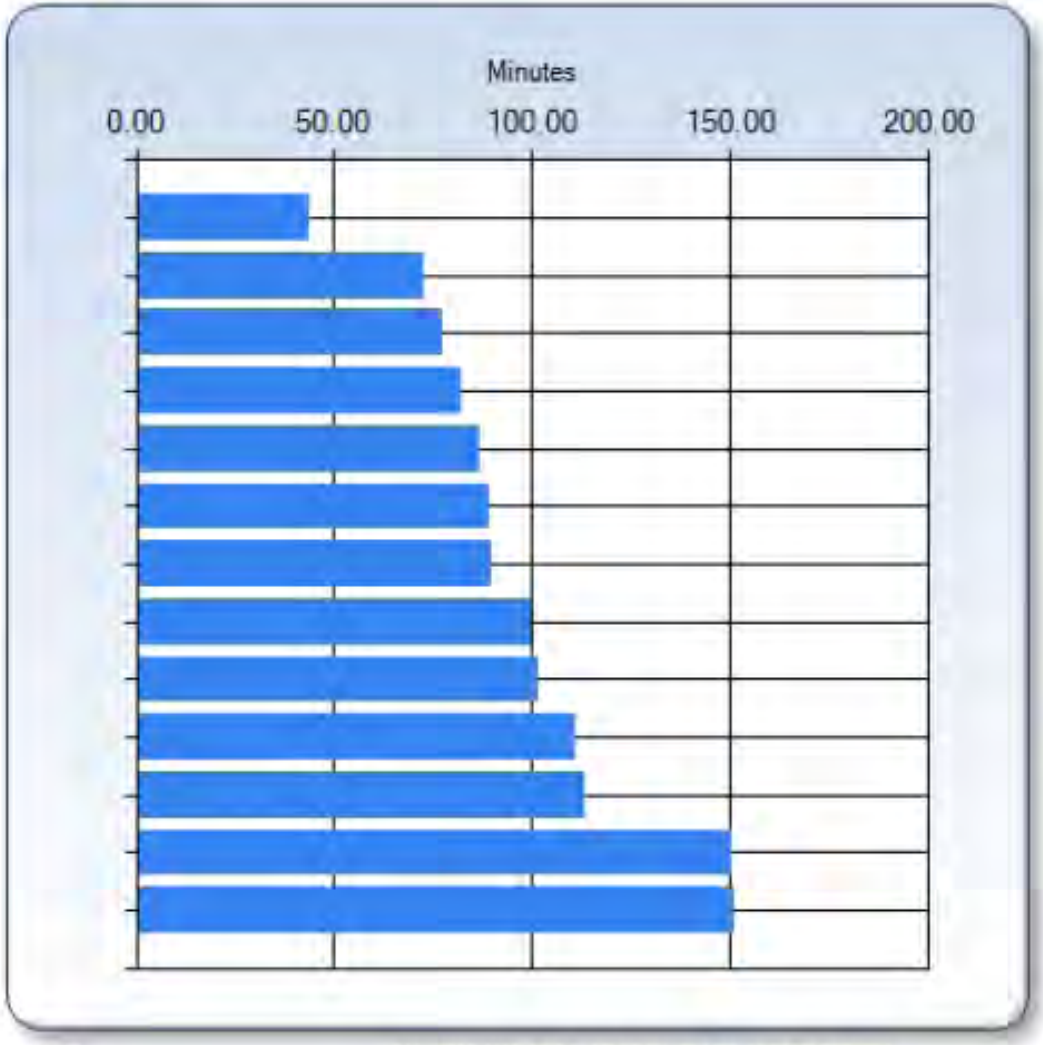
1| CAIDI (EXCLUDING MAJOR EVENTS USING 2.5 BETA METHOD)



Mean Quartile	
Mean	97.57
Quartile 1	81.99
Quartile 2:	90.00
Quartile 3:	111.00

Comments

Calculation used

Q1.3E

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4| MAJOR EVENTS DEFINED

	Responses	Comments
Total Participants	18	
Number of Respondants	14	

Calculation used

Q4.1

Response

A major event is where 10% of customers in an operating area are without power during a 24 hour period

Use IEEE/PES P-1366

sustained customer interruptions >= 10% of customers.

Interruptions that result from a catastrophic event that exceeds the design limits of the electric power system, such as an earthquake or an extreme storm. These events shall include situations where there is a loss of power to 10% or more of the customers in a region over a 24-hour period and with all customers not restored within 24 hours.

Storm events where restoration exceeds 24 hours duration.

Major Events are defined using the 'Beta Method' described in the IEEE Standard 1366 (2003)

using of the 2.5 beta method since 2006

A major event is defined as an uncontrollable event (e.g. windstorm, earthquake, forest fire, flood, lightning, etc) that causes an outage resulting in more than 70,000 customer hrs lost or in customer hours lost >=1% of annual customer hours lost for the distribution system. The definition excludes controllable causes such as equipment failure or human error at the distribution, substation or transmission level.

Major Events per IEEE 1366 2.5 Beta Method

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5% of customers effected in a sigle region or total service area; more than 48 hours to restore service; or cost to repair excedes a certain amount.

Using 2.5 beta method

Using 2.5 beta method in 2 out of 3 states (WA, CA); in OR using old method of 10% op area customers off and event exceeds design or operating limits.

The event that interrupted over 10% of our distribution customers.

A major event is declared whenever extensive physical damage to transmission and distribution facilities has occurred within MidAmerican's operating territory AND 1. Wind speed exceeds 90 mph for the affected area, or 2. One-half inch of ice is present and wind speed exceeds 40 mph for the affected area, or 3. Ten percent of the affected area total customer count is incurring a loss of service for a length of time to exceed five hours, or 4. 20,000 customers in a metropolitan area are incurring a loss of service for a length of time to exceed five hours. OR When a local area storm center is in operation, including storm center operations at the Control Center in Des Moines, for more than one day. OR When the IEEE P1366 statistical definition of Major Event Day is met for the entire MidAmerican Service Territory.

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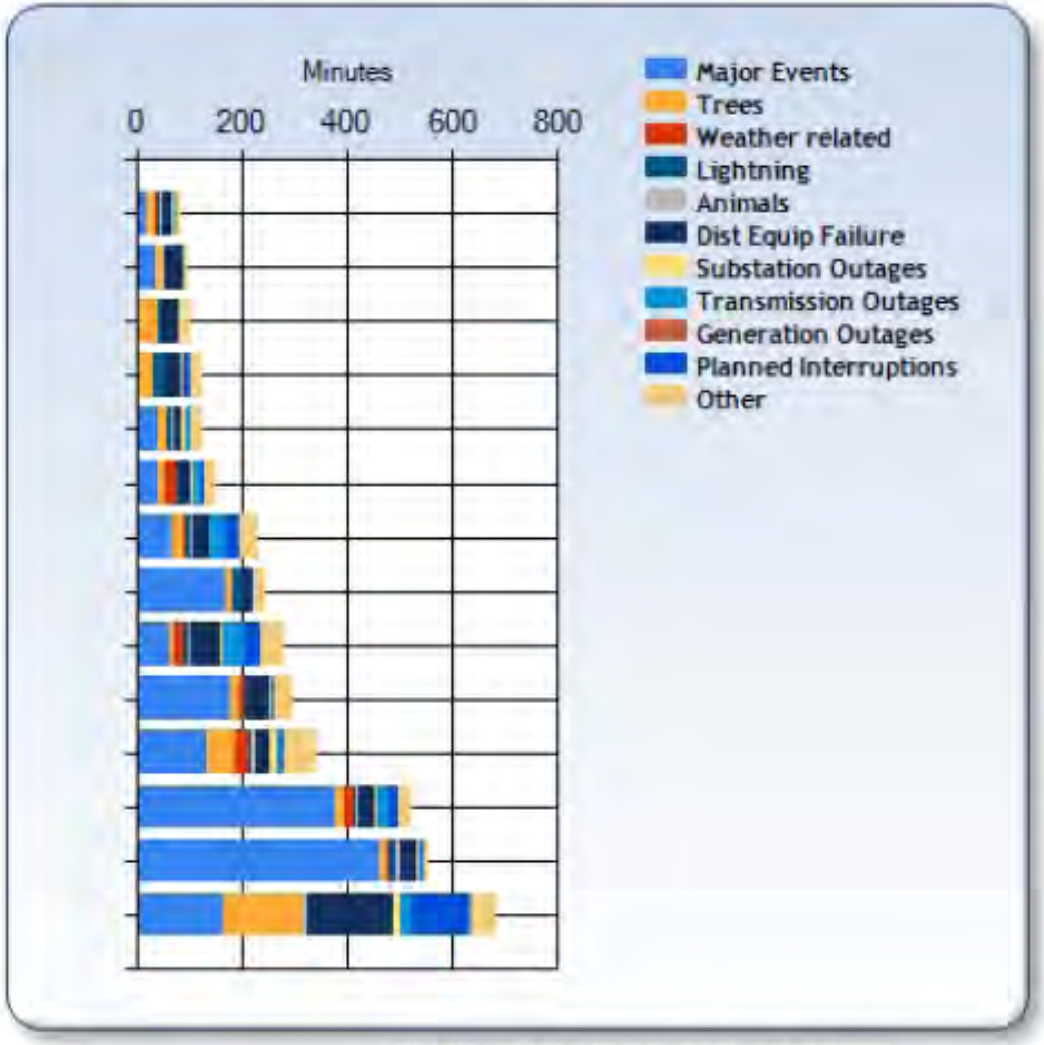
5| SAIDI STATISTICS BY CAUSE



Mean Quartile	
Mean	275
Quartile 1	125
Quartile 2:	239
Quartile 3:	331

Comments

Calculation used

Q5.1A, Q5.2A, Q5.3A, Q5.4A, Q5.5A, Q5.6A, Q5.7A, Q5.8A, Q5.9A, Q5.10A, Q5.11A

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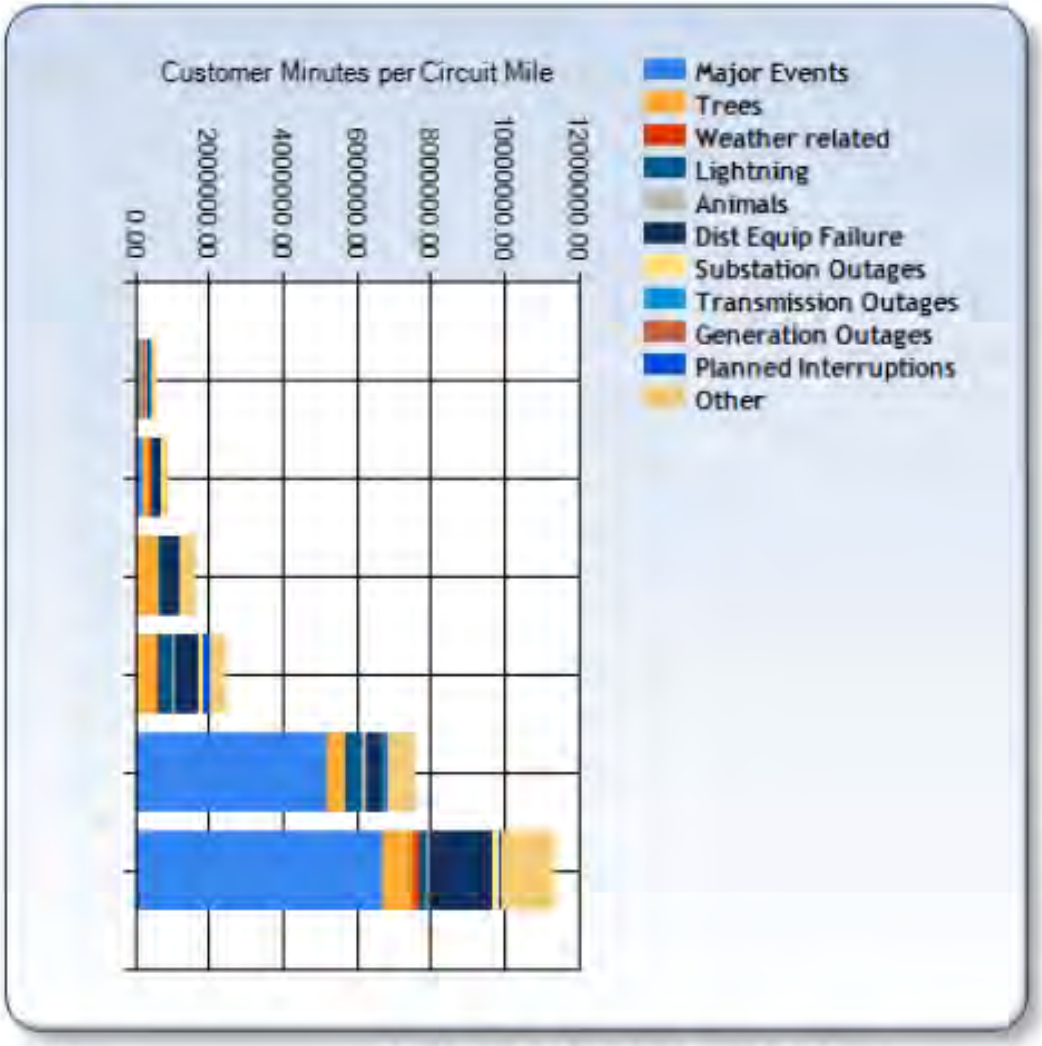
5| CUSTOMER MINUTES INTERRUPTED BY CAUSE PER CIRCUIT



Mean Quartile	
Mean	4107872.41
Quartile 1	1118443.09
Quartile 2:	2073471.96
Quartile 3:	6329174.04

Comments

Calculation used

Q5.1A * (T&D Dist End Use Customers) / (Dist circuits),
Q5.2A * (T&D Dist End Use Customers) / (Dist circuits),
Q5.3A * (T&D Dist End Use Customers) / (Dist circuits),
Q5.4A * (T&D Dist End Use Customers) / (Dist circuits),
Q5.5A * (T&D Dist End Use Customers) / (Dist circuits),
Q5.6A * (T&D Dist End Use Customers) / (Dist circuits),
Q5.7A * (T&D Dist End Use Customers) / (Dist circuits),
Q5.8A * (T&D Dist End Use Customers) / (Dist circuits),

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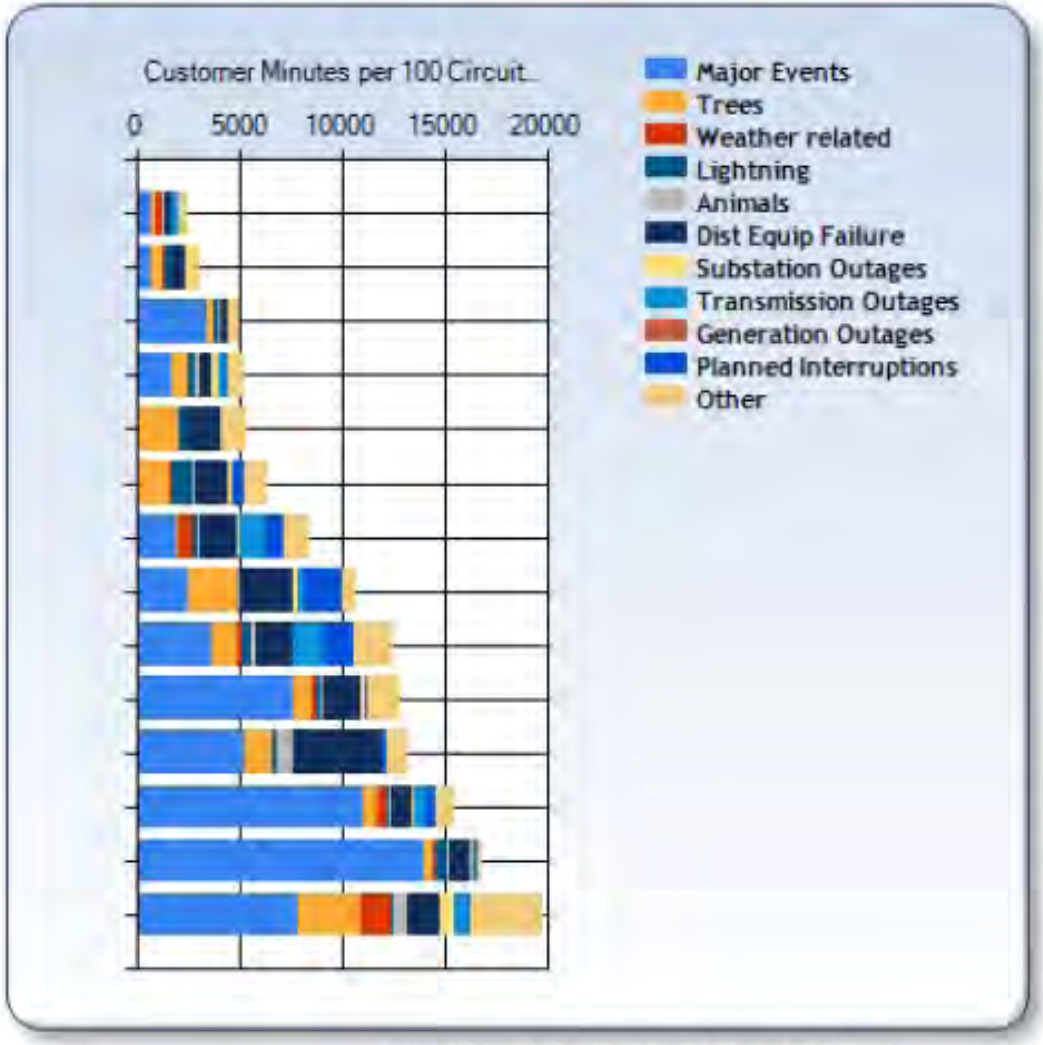
5| CUSTOMER MINUTES INTERRUPTED BY CAUSE PER 100 CIRCUIT MILE



Mean Quartile	
Mean	9846
Quartile 1	5319
Quartile 2:	9601
Quartile 3:	13120

Comments

Calculation used

Q5.1A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.2A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.3A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.4A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.5A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.6A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.7A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.8A *

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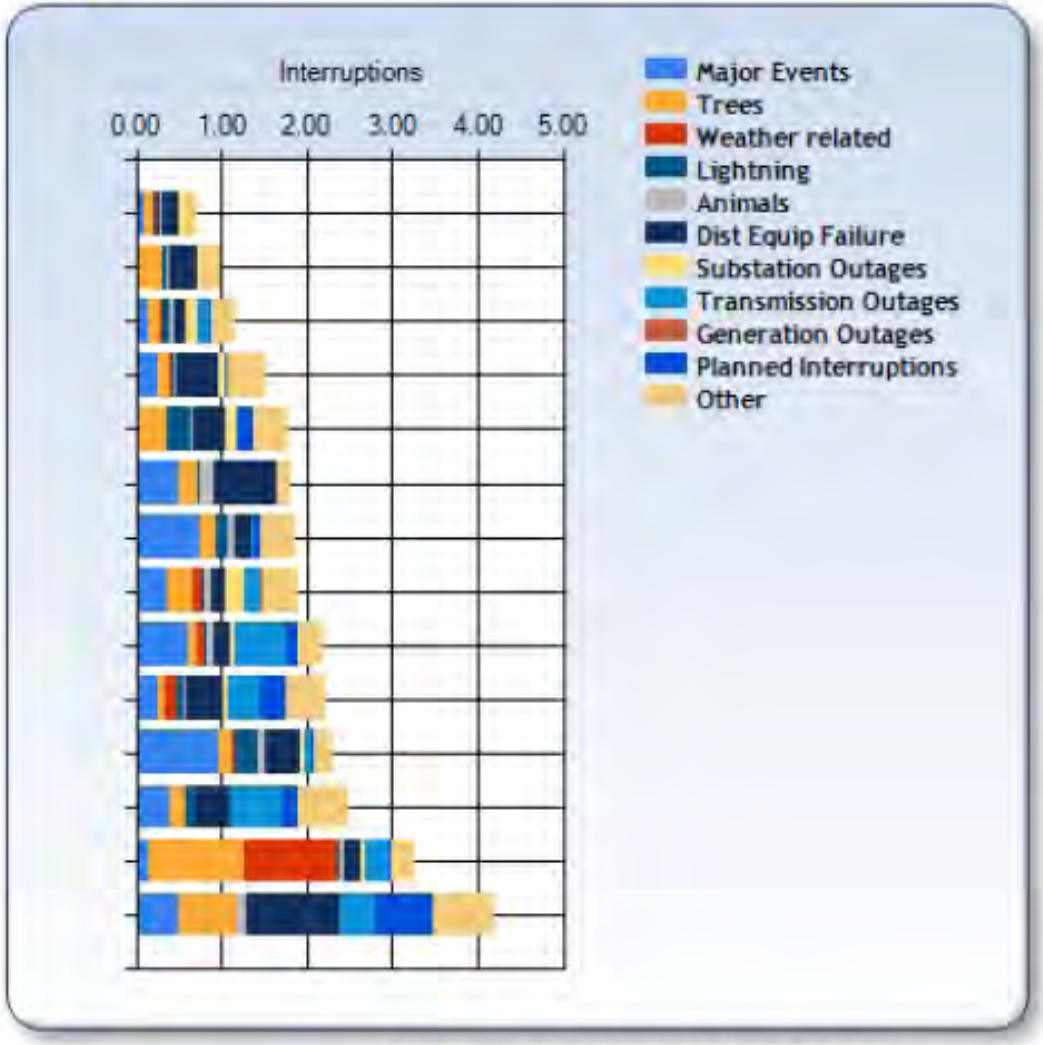
5| SAIFI STATISTICS BY CAUSE



Mean Quartile	
Mean	2.03
Quartile 1	1.59
Quartile 2:	1.88
Quartile 3:	2.29

Comments

Calculation used

Q5.1B, Q5.2B, Q5.3B, Q5.4B, Q5.5B, Q5.6B, Q5.7B, Q5.8B, Q5.9B, Q5.10B, Q5.11B

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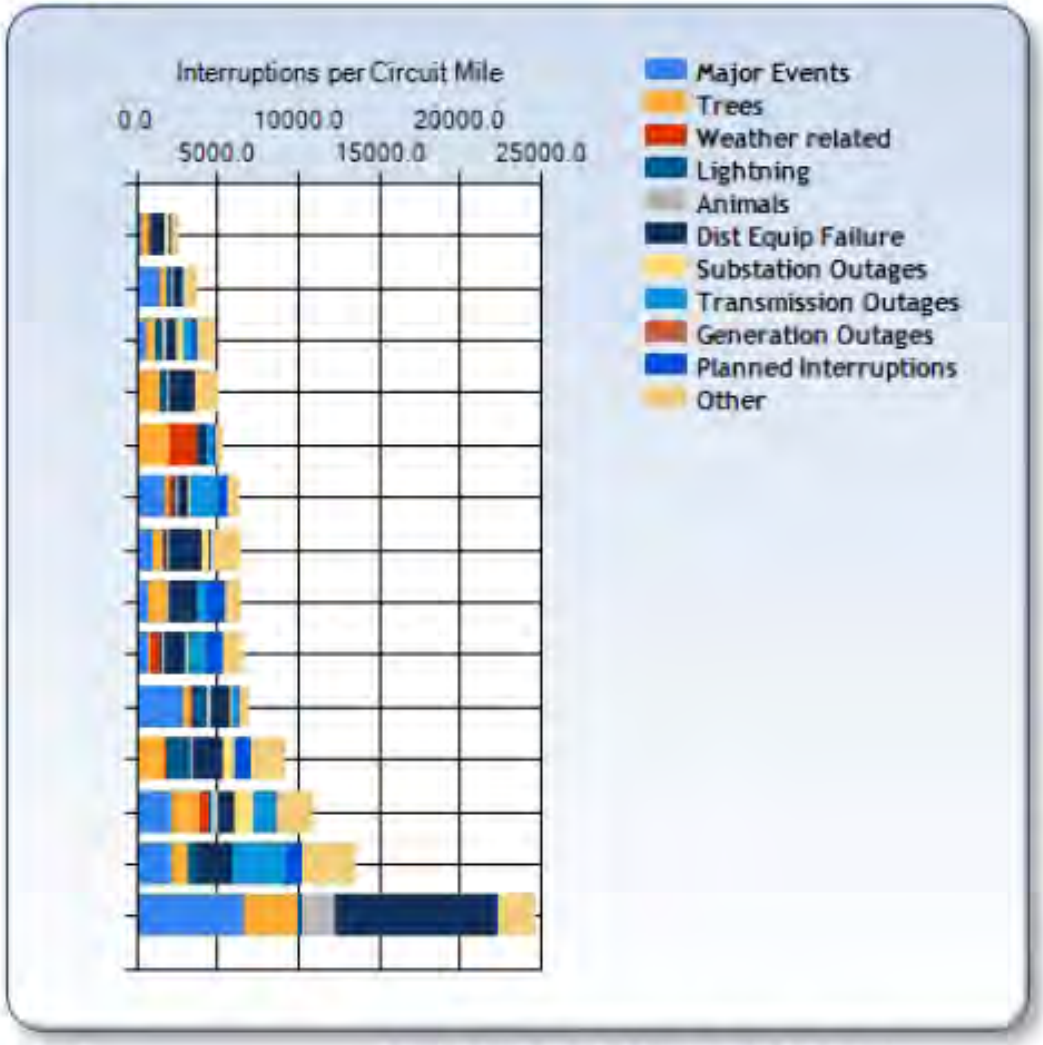
5| INTERRUPTIONS BY CAUSE PER CIRCUIT MILE



Mean Quartile	
Mean	8126
Quartile 1	5160
Quartile 2:	6560
Quartile 3:	8722

Comments

Calculation used

Q5.1B * (T&D Dist End Use Customers) / ((Dist Circ Miles) / 100), Q5.2B * (T&D Dist End Use Customers) / ((Dist Circ Miles) / 100), Q5.3B * (T&D Dist End Use Customers) / ((Dist Circ Miles) / 100), Q5.4B * (T&D Dist End Use Customers) / ((Dist Circ Miles) / 100), Q5.5B * (T&D Dist End Use Customers) / ((Dist Circ Miles) / 100), Q5.6B * (T&D Dist End Use Customers) / ((Dist Circ Miles) / 100), Q5.7B * (T&D Dist End Use

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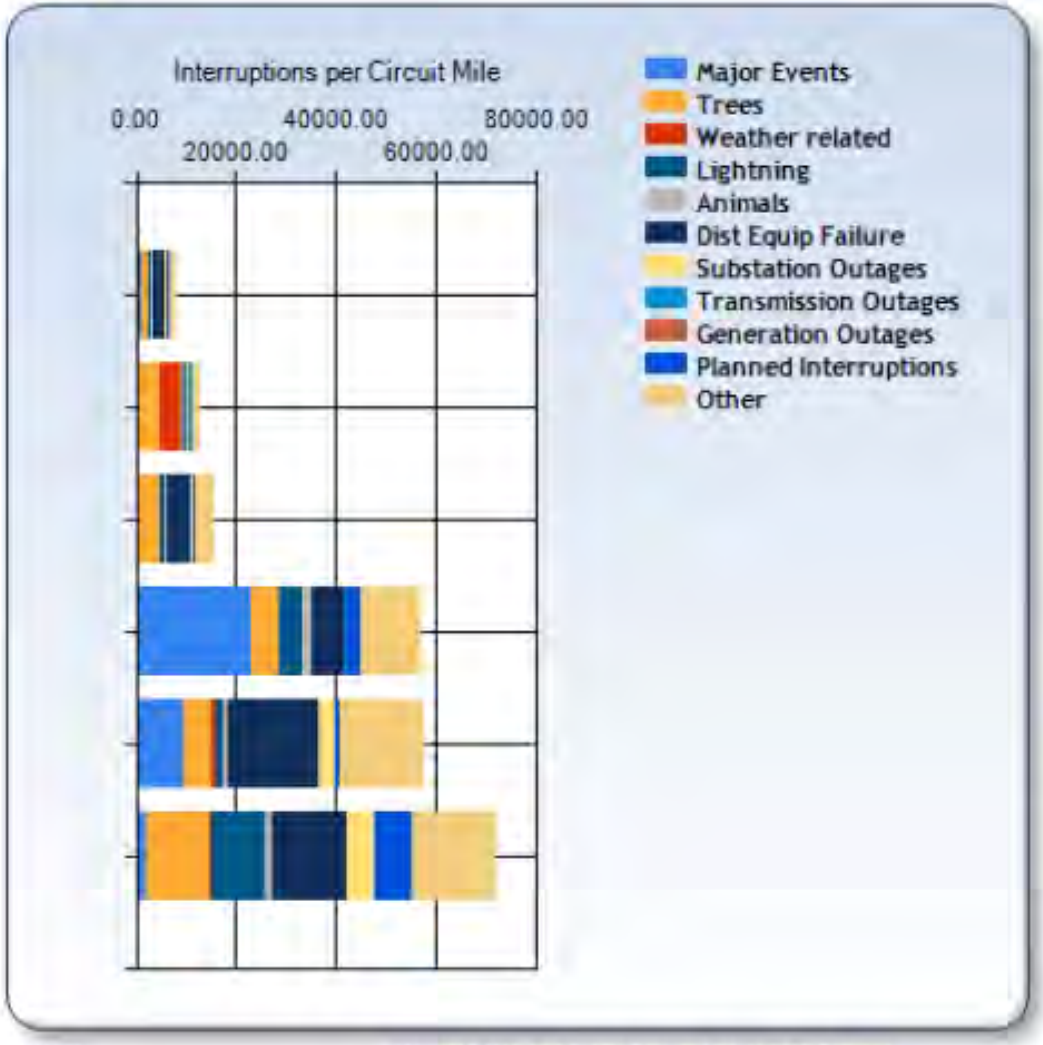
5| SAIFI INTERRUPTIONS BY CAUSE PER CIRCUIT



Mean Quartile	
Mean	37186.27
Quartile 1	13379.02
Quartile 2:	36401.31
Quartile 3:	57480.14

Comments

Calculation used

Q5.1B * (T&D Total Customers) / (Dist circuits), Q5.2B * (T&D Total Customers) / (Dist circuits), Q5.3B * (T&D Total Customers) / (Dist circuits), Q5.4B * (T&D Total Customers) / (Dist circuits), Q5.5B * (T&D Total Customers) / (Dist circuits), Q5.6B * (T&D Total Customers) / (Dist circuits), Q5.7B * (T&D Total Customers) / (Dist circuits), Q5.8B * (T&D Total Customers) / (Dist circuits), Q5.9B * (T&D Total

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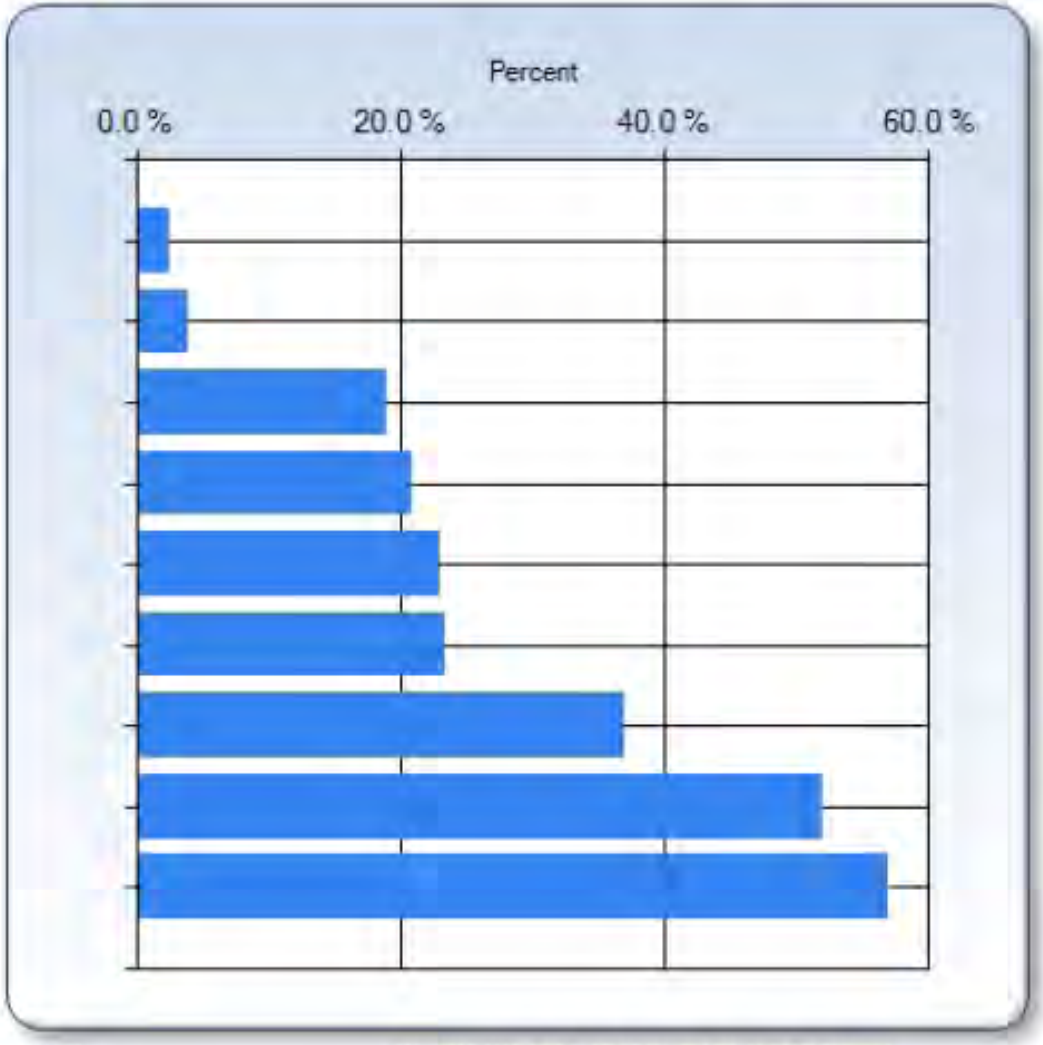
6| PERCENT OF CIRCUITS REPEATED IN THE BOTTOM 10% LAST YEAR - USING SAIDI CRITERIA



Mean Quartile	
Mean	26.6 %
Quartile 1	19.0 %
Quartile 2:	23.0 %
Quartile 3:	37.0 %

Comments

Calculation used

Q6.1

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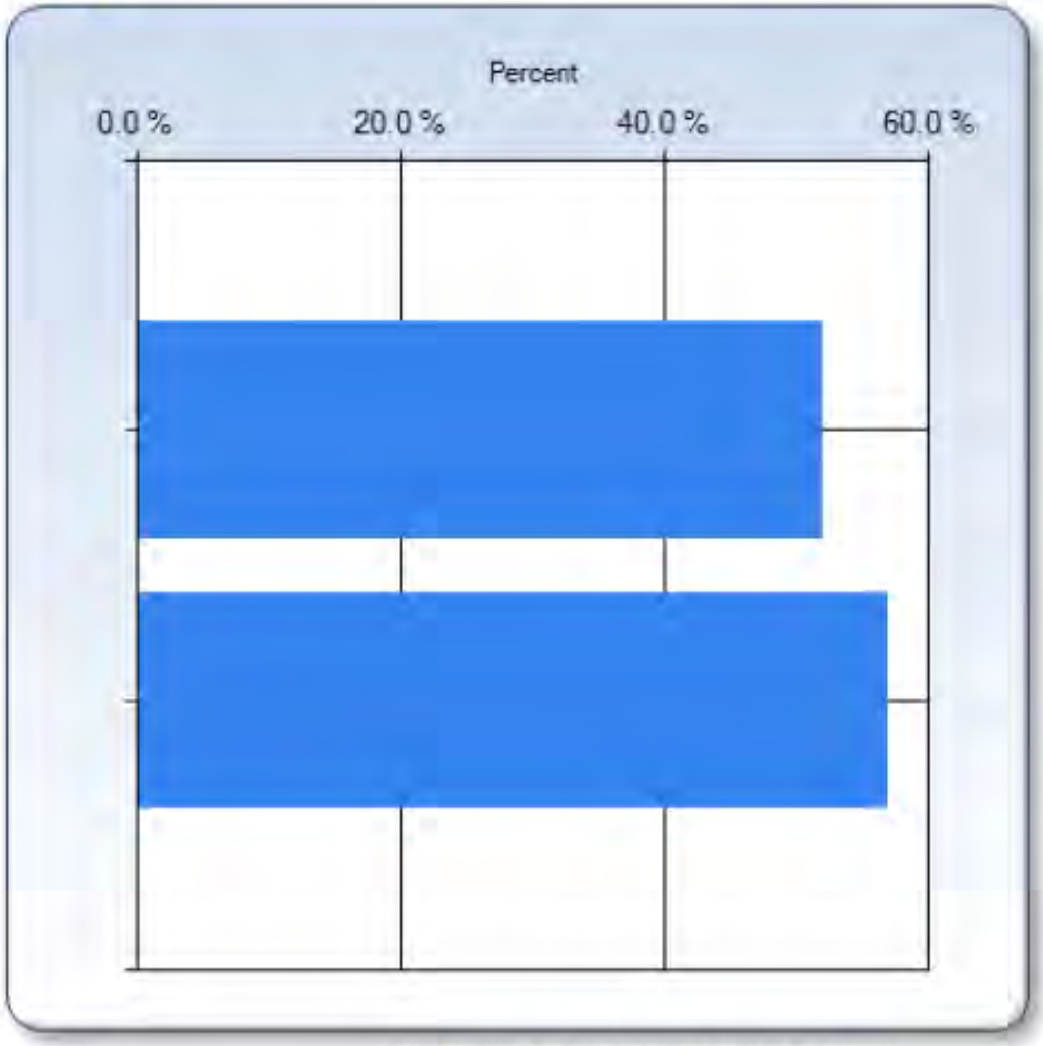
6A| PERCENT OF CIRCUITS REPEATED IN THE BOTTOM 10% LAST YEAR - USING SAIFI CRITERIA



Mean Quartile	
Mean	54.5 %
Quartile 1	53.3 %
Quartile 2:	54.5 %
Quartile 3:	55.8 %

Comments

Calculation used

Q6a.1

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7| AVERAGE SAIDI FOR THE WORST 10% OF CIRCUITS LAST YEAR



Mean Quartile	
Mean	837.1
Quartile 1	303.0
Quartile 2:	350.6
Quartile 3:	1467.2

Comments

Calculation used

Q7.1

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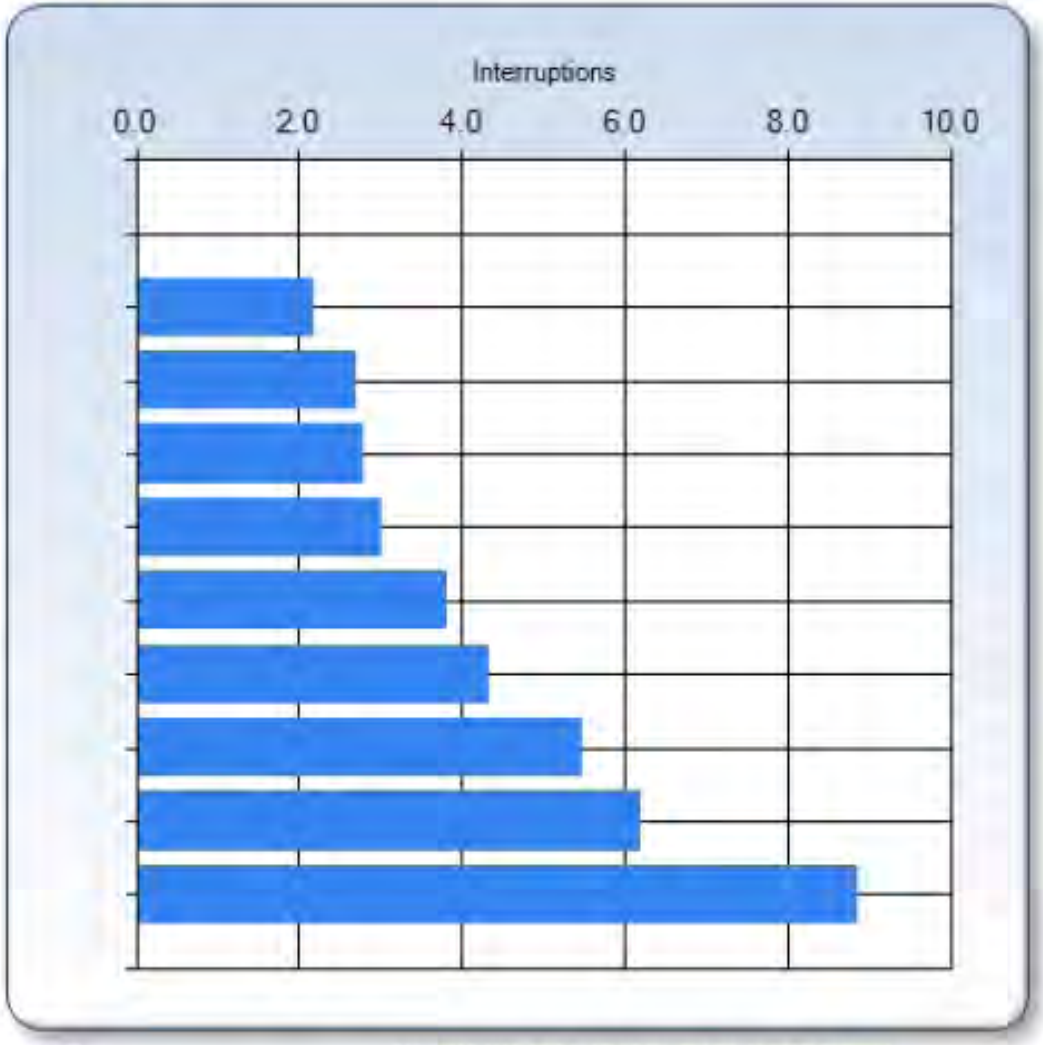
7| AVERAGE SAIFI FOR THE WORST 10% OF CIRCUITS LAST YEAR



Mean Quartile	
Mean	3.9
Quartile 1	2.7
Quartile 2:	3.4
Quartile 3:	5.2

Comments

Calculation used

Q7.2

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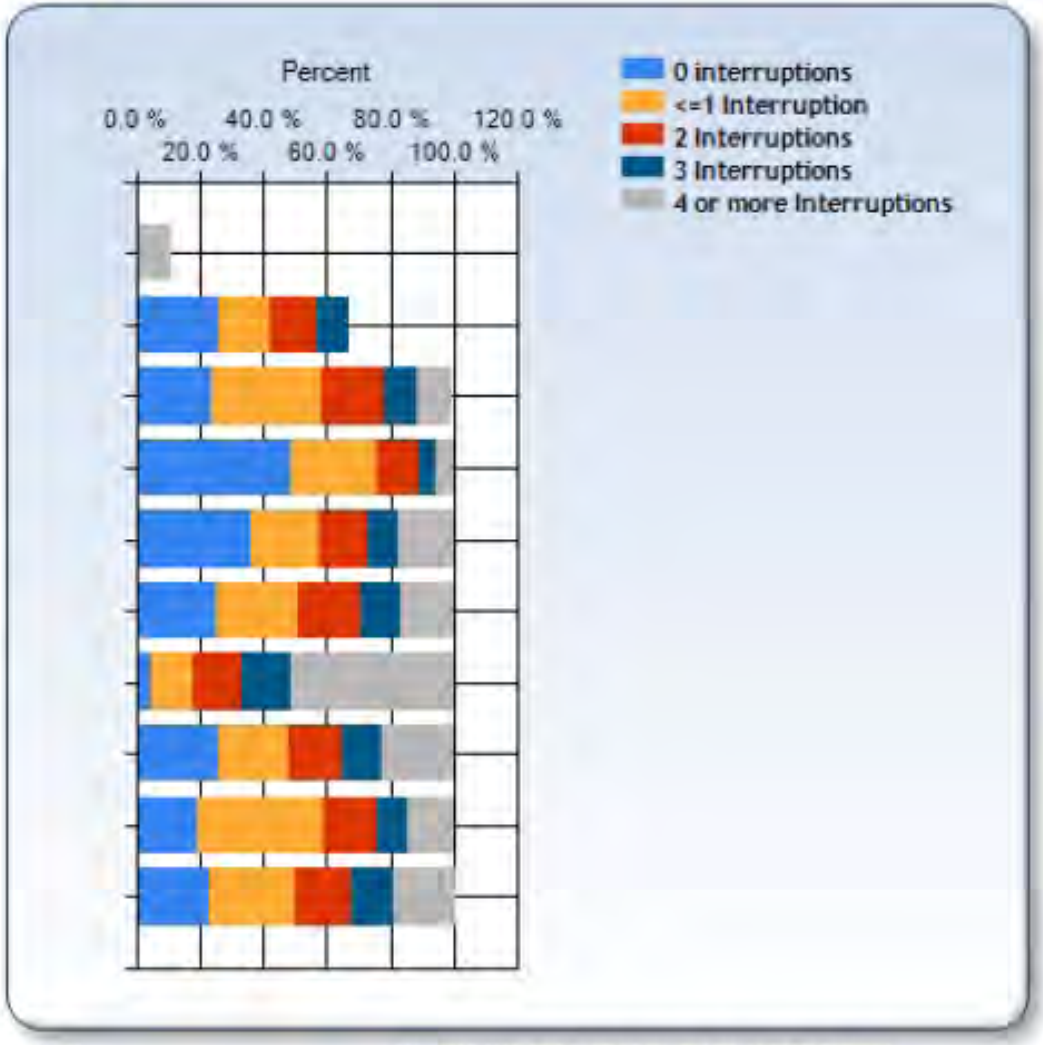
8| PERCENT OF CUSTOMERS IN EACH CATEGORY - BY NUMBER OF INTERRUPTIONS LAST YEAR



Mean Quartile	
Mean	87.9 %
Quartile 1	99.7 %
Quartile 2:	100.0 %
Quartile 3:	100.0 %

Comments

Calculation used

Q8.1A, Q8.1A, Q8.1A, Q8.1A, Q8.1A

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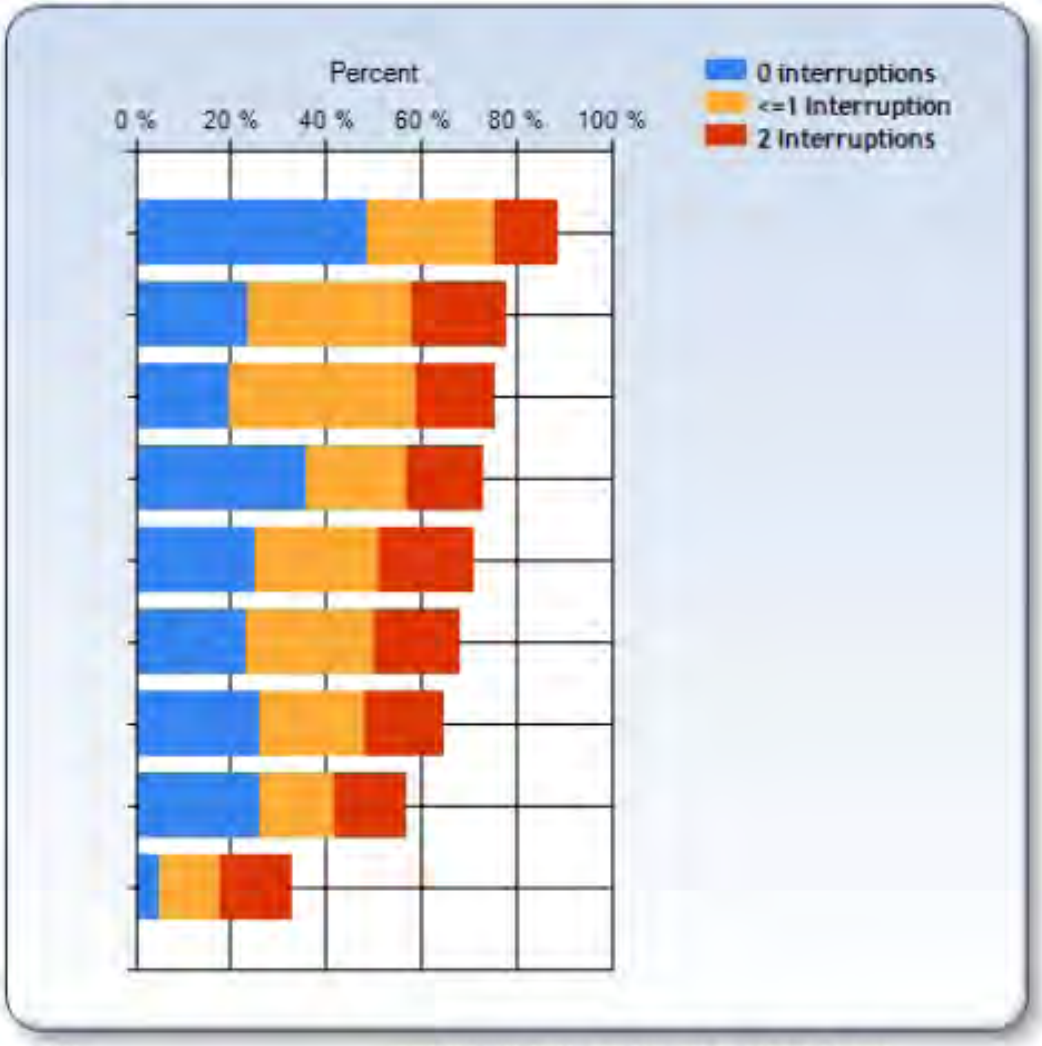
8| PERCENT OF CUSTOMERS WITH <3 INTERRUPTIONS LAST YEAR



Mean Quartile	
Mean	68 %
Quartile 1	76 %
Quartile 2:	71 %
Quartile 3:	65 %

Comments

Calculation used

Q8.1A, Q8.1A, Q8.1A

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9| MAXIMUM NUMBER OF SECONDS FOR AN OUTAGE TO BE CLASSIFIED AS MOMENTARY



Comments

Calculation used

Q9.1

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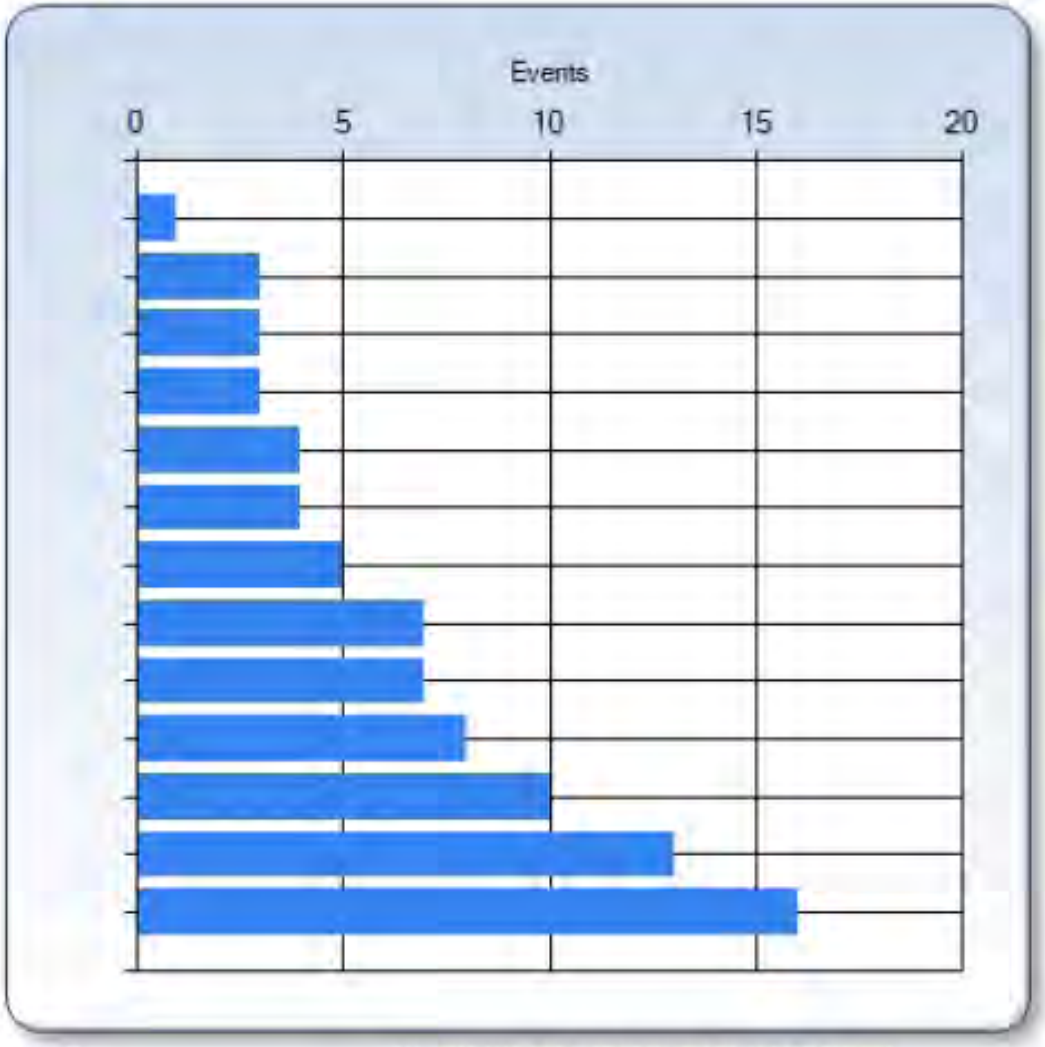
10| MAJOR EVENTS EXPERIENCED THE LAST THREE YEARS



Comments

Calculation used

Q10.1A

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11| PLEASE DESCRIBE ANY EFFECTIVE STRATEGIES USED TO IMPROVE THE EFFECTIVENESS OF THE OUTAGE MANAGEMENT SYSTEM?

	Responses	Comments
Total Participants	18	
Number of Respondants	12	

Calculation used

Q11.1

Response

Updating mapping systems to minimize unmapped customers. Currently at 97% accurate.

mid-cycle trim on 34kV circuits (2.5 years)

Use GPS to assign closest qualified crew to outage location. OMS sends messages via Mobile Data to crew's laptop & pager to let them know that they have a new outage order, the priority of the order, whether or not there have been reoccuring outages on the suspected equipment, if the circuit the order is on is on the worst 10% list or has the potential to be on the list in the upcoming year, etc. Color is used in OMS and MDS to indicate different priorities or age of orders. Crew can see the estimated number of customers affected by an outage & if needed, can see the addresses for callers & what they reported to be the problem. They also have access to the customers' phone numbers should they need to contact the customer directly. (This is particularly helpful when they pull up at a business & need to make contact with the proper person or if they can't find the condition the customer has called about. Reports are generated for management to ensure that crews are entering receipt, in route, on site, and estimated on times for all cases of trouble. (All except estimated on time can be done by simply pressing a button at the proper time.) This data is passed through Mobile Data to OMS and is available to Customer Contact Agents & IVRs. A quality assurance team looks at any extended outage cases or questionable data pointed out by a daily report. Have shaved minutes off CAIDI and SAIDI by correcting data entry errors. Before correction, screen prints are made & sent to the crew's supervisor for training purposes. If the QA team sees a trend in errors, training documentation is created and distributed to be sure crews understand the proper way to use the application. Graphical switching applications tied to OMS & GIS allow for quicker generation of switching orders & for the temporary and permanant changes to the distribution system to be viewed by users outside of Dispatching. Inquiry only applications on the company Intranet allow those outside of Dispatching & Operations to view data without affecting the

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performance of OMS. OMS sends data to the Intranet files in near real time. OMS sends data to an Intranet GIS application called Outage Tracker. During major events, this tool is quite helpful for management to get a visual of where the majority of trouble is and which cases have been dispatched.

Improve accuracies of the underlying GIS system and customer connectivity.

SCL has not used an OMS in the past. Currently in the process of aquiring OMS

remote devices, proactive outlook on events, outage and event alarm on pagers

Splitting dispatch areas. Sort by feeder. Customizations of the OMS. Users limited to Dispatch Centre staff. OMS user trainers/experts within the Dispatch staff.

"restore before repair", adequate line personnel, line coordinations, more sectionalizing points, GIS mapping

More focus on data quality and the use of the output data

More focus on data quality and the use of the output data

Best practice visit to other utilities

Active and outspoken participation in OMS User Group have improved the effectiveness.

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12| PLEASE DESCRIBE ANY EFFECTIVE STRATEGIES USED TO IMPROVE THE EFFECTIVENESS OF DISPATCHING TO REDUCE OUTAGE DURATIONS?

	Responses	Comments
Total Participants	18	
Number of Respondants	12	

Calculation used

Q12.1

Response

Implemented Mobile Data to all first responders/troubleshooters and set expectations that any outage would be dispatched within 5 minutes, arrived within 20 minutes, and resolved within 90 minutes.

Installing sectionalizers.

Set and measure goals for average dispatch time. Set and measure goals for the restoration of circuits, fuses, and to use distribution automation within certain time frames. Storm days are included in the calculations. Monthly reports are delivered to management to verify if goals have been met. Posters of the report are posted where Dispatching personnel can see how well they are doing. A LED 'Crawl' is on the wall & constantly displays messages reminding Dispatchers of their goals, the current progress to meet the annual goal, and the current and target reliability indices.

Implement a "10 minute plan" to dispatchers, first responders, and line techs to designed to lower restoration times.

Step Restoration - Multiple Crews

assigned crews on outage, stand by crews out of business hours

Identification of a key call which may be where the problem is.

Direct center calls to troublemen.

Analysis of time of day/month of year peaks for better shift alignment with high volumes.

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Analysis of time of day/month of year peaks for better shift alignment with high volumes

None at this time

First responders are available in many areas. When first responders are fully utilized line crews are utilized as first responders in an effort to keep response times as low as possible. The control center teams are divided geographically so one operator is responsible for only a discreet subset of the operational area thus better focusing the operator's attention on his area of responsibility.

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13| WHAT MAJOR CHALLENGES ARE BEING ENCOUNTERED – NEAR-TERM AND LONG-TERM – THAT ARE CAUSING NEW BEHAVIORS/STRATEGIES?

	Responses	Comments
Total Participants	18	
Number of Respondants	10	

Calculation used

Q13.1

Response

Age & condition of distribution system equipment, increasing customer expectations. Age of workforce is also a near term factor. Long range staffing plan being developed to explore hiring practices as well as the use of contractors for specific occupations.

Addressing reliability while dealing with budgetary constraints. Meeting PUC mandatory dates for certain types of orders. Hiring new Helpers means that experienced field personnel have to explain what needs to be done at a job, how they will do it, & why they are doing it that way. Knowledge transfer. Pushing internal crews and contractors to keep reliability indices at a satisfactory rate while sending crews for mutual assistance.

Three worst circuit lists 1) Worst circuit ranking using 4yr avg SAIFI/CI 2) Worst Circuit CEMI ranking 3) Worst Circuit rankings using re-occurring outages on a Device.

aging for majority of linemens and lack of availability from new linemens

Customer Experience initiatives. Business continuity planning. Crew availability.

Aging workforce, GIS mapping, digital equipment, smart metering/grid

Continued stress upstream on substation and transmission assets

Continued stress upstream on substation and transmission assets

Dispatch staff is high turn over

The effort to continue improving reliability indices at the system, circuit and customer level is an on-going challenge in both the short and long terms. Several initiatives contained in MidAmerican's CAIDI/SAIFI Improvement Plan have been implemented to address this

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14| HOW DO YOU MANAGE TRADEOFFS BETWEEN COST AND RELIABILITY?

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q14.1

Response

System reliability improvements are evaluated on a case by case basis and focused on causes and targeted areas.

prioritize ccts

Indices are taken into consideration when determining daily staffing. Example: If we are far ahead of our targets, a supervisor may not replace people who are off on vacation to save overtime on a blue sky day. We do as much work 'hot' as is safely possible to avoid service interruption. Use all weather information available, along with contact with other utilities who have already been hit with the storm to try to staff correctly for possible high volume situations. Being properly positioned for these events can shorten the length of time needed for restoration and as a result, save payroll dollars. We use lightning detection, Doppler Radar, The National Weather Service, a local weather service, The Weather Channel, local news reports, and information from company personnel to collect the necessary weather data needed to forecast the degree of damage we can expect and what part of the territory will be most affected. We use all the technology we have to eliminate unnecessary field trips. Examples: On blue sky days, Dispatching personnel will call customers when all signs point to a single location problem. Qualified personnel can many times help the customer to resolve their problem over the phone. In storms, non-emergency single location outage orders are addressed last in the restoration process. When the orders begin to 'age', an outbound IVR process is used to call the customer who can press a button or speak their reply to determine if they are still without power. We find that we eliminate hundreds of field trips in a major event. (Common reasons: The customer has grown tired of waiting & has reset their own breaker. The customer was calling about circuit operations which ceased as the weather cleared. The customer was not assigned to the correct transformer / distribution network & thus their order did not localize with the proper outage case. (These can be given immediately to GIS personnel assigned to work in the Dispatch Office for the proper network assignment.)

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Planning to measure the cost of reliability projects to better understand cost/benefit.

There is no specific criteria that determine what is allowed to spend to meet reliability target except for major programs like Distribution Automation

We use a value based project optimization tool that compares projects based on all corporate values (Financial, Reliability, People, Environment, etc.). The weightings for each account are set with full corporate input.

budget, guidelines, operational consensus

Look for low hanging fruit with programs that deliver high improvement at reasonable cost

Look for low hanging fruit with programs that deliver high improvement at reasonable cost

Through Risk Assesment Process

The MidAmerican valuation of system reliability improvements is based upon the results of a customer reliability survey completed in 2002. Customer responses to the survey were used to develop a customer damage function for each class of customers, which represents the estimated costs that the customers incur for outages of various durations. Customers therefore would value avoiding those outage costs at the same rate. The customer damage function, or customer value of reliability, is then used in conjunction with estimates or historical outage probabilities and durations to identify the annual customer reliability benefit associated with a particular system upgrade. The reliability improvements on a customer value basis are then entered into a capital project prioritization program in which all discretionary projects affecting a range of attributes are ranked to identify those that provide the greatest value to the company on a cost-benefit basis.

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15| PLEASE DESCRIBE ANY SUCCESSFUL INITIATIVES USED TO IMPROVE WORST CIRCUIT PERFORMANCE?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q15.1

Response

Worst Performing Circuit Program: patrols, equipment replacement, forestry, lightning & wildlife protection, protection reviews.

feeder assessment, change in circuit inspection

Redesign of entire process which includes coordination & goal dates set for each group involved in the initiatives. (Example: Completion dates set for inspections, issuing work orders, tree trimming of worst 10% circuits, and execution of work orders.

Feeder Rehab project was a pilot that

Identifying our worst circuits performance and causes analysis

"A Customer Based Reliability Program (CBR) was developed by grouping customers into 6 customer segments with similar reliability expectations in frequency and duration. This methodology is used to identify worst performing circuits. Performance requirements based on these customer expectaions were estimated and transformed to the individual feeders based on the major CBR customer segment for the individual feeders. Actual reliability performance was compared to the estimated requirements; the resulting gaps became the focus of the system improvements. The CBR program has shown focussed improvement to these worst performing circuits in terms of customer hours lost: in F2007 466 circuits were identified with varying gaps to the target customer performance level, and showed a 26% improvement in normalized customer hours lost compared to the previous 3 year average "

improved coordination, vegetation management, inspections, animal protection

Feeder Analysis Program

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On an annual basis distribution electric circuit reliability data for each circuit is evaluated and the 10 worst performing distribution circuits are targeted for reliability improvement. Improvements may include animal guards, lightning arresters, cut-out installations, overhead line and pole replacement, underground cable replacement and tree problem identification. A written plan is developed and all reliability improvements are completed by year-end. Also, any of the initiatives included in the CAIDI-SAIDI-SAIFI Plan described in the responses to Q16, Q17 and Q18 that affect worst performing circuits will improve reliability performance of those circuits.

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16| WHAT WAS THE MOST IMPORTANT INITIATIVE TAKEN TO IMPROVE SAIDI?

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q16.1

Response

This is addressed through the SAIFI and CAIDI improvement efforts.

Redesign of reactive tree trimming process Goals times set for restoration of circuits and fuses. Posters at each service center let the personnel see the corporate goal and the percentage of time that month the center has met that goal. Executive and local management are highly involved in the commitment to improve SAIDI. They speak to field personnel about the importance of SAIDI. Emails are sent out by executives & posted where they can be seen by field personnel, congratulating them on great work if we are exceeding SAIDI targets. Encouraging emails are sent & posted if we are in danger of not meeting SAIDI targets. SAIDI targets are part of the KPMs used to determine annual bonuses and additional 401K matching.

Worst circuits and 10 minute plan

Trim More Trees

Installation of remote controlled switches (Distribution automation program)

An ongoing 5-year system-wide program, called System Resiliency, to reduce the impact to our system due to storms.

vegetation management

Focusing on accountability for each of the input metrics

Focusing on accountability for each of the input metrics

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More sectionaliers on 44KV system, increase vegetation program(cycles)

The most important initiative was the development of MidAmerican's CAIDI-SAIDI-SAIFI improvement plan. This plan contains several initiatives to improve the reliability indices. Examples include: 1) Reduce Call and Dispatch Delays (CAIDI-SAIDI), 2) Enhance allocation of field resources (CAIDI-SAIDI), 3) Outage Process Improvement (CAIDI-SAIDI), 4) Review abnormal devices in EOMS and in the field and perform upgrades or work arounds as required. (CAIDI/SAIDI/SAIFI), 5) Analyze and correct galloping conductors (CAIDI/SAIDI/SAIFI), 6) Perform vegetation only aerial patrol for vegetation encroachment. Schedule and complete any follow-up that may be required. (CAIDI/SAIDI/SAIFI, 7) Inspect critical devices - Reclosers, Regulators, other - and schedule and make repairs as needed and as man-power allows. (CAIDI/SAIDI/SAIFI), 8) Perform reliability improvements on the 10 Worst Circuits/20 Worst Protective Devices (CAIDI/SAIDI/SAIFI), 9) Review customers and protective devices with multiple outages during a defined period (3 or more outages during a rolling three-months window or 7 or more outages during a rolling 12 month window). Perform reliability upgrades as warranted.

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17| WHAT WAS THE MOST IMPORTANT INITIATIVE TAKEN TO IMPROVE SAIFI?

	Responses	Comments
Total Participants	18	
Number of Respondants	12	

Calculation used

Q17.1

Response

The Worst Performing Circuit Program and substation improvements.

additional tree trimming.

Redesign of reactive tree trimming process

Worst circuits

Trim More Trees

There is no specific target to improve SAIFI however we started to measure this indicator

The CBR program mentioned in Q15.

better coordination

Systematic protection, including fuse coordination, recloser installation, relay upgrades and coordination

Systematic protection, including fuse coordination, recloser installation, relay upgrades and coordination

Increase vegetation program(cycles)

The most important initiative was the development of MidAmerican's CAIDI-SAIDI-SAIFI improvement plan. This plan contains several initiatives to improve the reliability indices. Examples include: 1) Reduce Call and Dispatch Delays (CAIDI-SAIDI), 2) Enhance allocation of field resources (CAIDI-SAIDI), 3) Outage Process Improvement (CAIDI-SAIDI), 4) Review abnormal devices in EOMS and in the field and

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perform upgrades or work arounds as required. (CAIDI/SAIDI/SAIFI), 5) Analyze and correct galloping conductors (CAIDI/SAIDI/SAIFI), 6) Perform vegetation only aerial patrol for vegetation encroachment. Schedule and complete any follow-up that may be required. (CAIDI/SAIDI/SAIFI, 7) Inspect critical devices - Reclosers, Regulators, other - and schedule and make repairs as needed and as man-power allows. (CAIDI/SAIDI/SAIFI), 8) Perform reliability improvements on the 10 Worst Circuits/20 Worst Protective Devices (CAIDI/SAIDI/SAIFI), 9) Review customers and protective devices with multiple outages during a defined period (3 or more outages during a rolling three-months window or 7 or more outages during a rolling 12 month window). Perform reliability upgrades as warranted.

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18| WHAT WAS THE MOST IMPORTANT INITIATIVE TAKEN TO IMPROVE CAIDI?

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q18.1

Response

Troubleshooters responding and repairing rather than a crew. 90% of all outages resolved by troubleshooter. Much of this is cut and clear, bridge load, and repair later.

Redesign of service restoration process

10 minute plan

Trim More Trees

Installation of remote controlled switches (Distribution Automation Program)

The CBR program mentioned in Q15.

restoring customers before repairing damage.

Regular attention to metrics that drive response, including analysis of call to response/response to restore

Regular attention to metrics that drive response, including analysis of call to response/response to restore

More sectionaliers on 44KV system

The most important initiative was the development of MidAmerican's CAIDI-SAIDI-SAIFI improvement plan. This plan contains several initiatives to improve the reliability indices. Examples include: 1) Reduce Call and Dispatch Delays (CAIDI-SAIDI), 2) Enhance allocation of field resources (CAIDI-SAIDI), 3) Outage Process Improvement (CAIDI-SAIDI), 4) Review abnormal devices in EOMS and in the field and

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perform upgrades or work arounds as required. (CAIDI/SAIDI/SAIFI), 5) Analyze and correct galloping conductors (CAIDI/SAIDI/SAIFI), 6) Perform vegetation only aerial patrol for vegetation encroachment. Schedule and complete any follow-up that may be required. (CAIDI/SAIDI/SAIFI, 7) Inspect critical devices - Reclosers, Regulators, other - and schedule and make repairs as needed and as man-power allows. (CAIDI/SAIDI/SAIFI), 8) Perform reliability improvements on the 10 Worst Circuits/20 Worst Protective Devices (CAIDI/SAIDI/SAIFI), 9) Review customers and protective devices with multiple outages during a defined period (3 or more outages during a rolling three-months window or 7 or more outages during a rolling 12 month window). Perform reliability upgrades as warranted.

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19| PLEASE DESCRIBE ANY SUCCESSFUL STAFFING PRACTICES USED DURING OFF-HOURS TO REDUCE DURATION OF OUTAGES?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q19.1

Response

Calling closest off shift troubleshooter, on call crews, and second shift crews.

Guarenteed 4 hours of double time for responding to call out. Duty weeks are assigned to crews at each service center. Members of these crews know that they must be able to be reached by phone & must be ready to respond quickly to call out. Weather forecasts are sent to Operations personnel along with messages to prepare for call out if the forecast calls for bad weather.

We run reports to measures normal workload by shifts. We have resources scheduled to handle normal workload 24x7- 7 days a week. Adjust schedule for holidays, weekends, peak times, special events, and predicted weather. Utilize an on-call list is needed.

Two Trouble Crews on Swing Shift, One Trouble Crew on Graveyard Shift

waged stand by crews with pagers response time for dispatch = 10 min.

Standby crews.

Servicemen take vehicles home

None available

Some operations areas have first responders on the street around the clock and many other areas have on-call first responders that can rapidly respond to outages. Some other operational areas have line-crews on call in addition to first responders. This has helped limit response time to outages. The control center has a 4-person shift on duty 24 hours per day. Additionally, there is a full team available to be called in should after-hours activity warrant the call.

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20| UNDER WHAT CONDITIONS DO YOU PROVIDE ESTIMATED RESTORATION TIMES?

	Responses	Comments
Total Participants	18	
Number of Respondants	12	

Calculation used

Q20.1

Response

All

We normally provide ERT's. In storms ERT are given after an assessment is made.

'Normal' days, computer generated estimate given on on trouble orders & updated through mobile data when crew arrives on scene & determines a more accurate restoration time. On storm days, automated estimated times suspended, but up front Customer Service message may be changed to give an estimated ERT for all of the territory. Individual ERT for individual trouble cases are entered via Mobile Data when crew arrives on scene & determines restoration time. Mobile data entries post in OMS within 8 seconds, allowing the most current ERT to be passed on to callers. Crew or planned outages require the crew to give an ERT which is entered into OMS along with the additional outage data. Reports are generated for Operations Supervisors to allow them to see that ERTs are being entered appropriately by their employees.

We provide estimated restoration times after the crew gets onsite, assess the job, and communicates back to the Distribution Control Center with the information of what was found, what caused the outage if known, and how long it will take to restore service. Information is entered into the OMS which provides information to the CSR's. We provide advanced phone notification to customers for planned outages that affect 100 or more customers or critical areas. The recording will tell them when the outage will occur and estimated restoration times.

Majority of outages get estimated restoration times.

any time ERT is included in OMS

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Every outage at point of dispatch.

When provided by the crew on-site

Under routine operations, when sufficient resources are in queue that historic estimates are valid.

Under routine operations, when sufficient resources are in queue that historic estimates are valid.

All conditions

Blue sky weather days only

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21| WHAT METHOD IS USED TO ESTIMATE RESTORATION TIMES?

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q21.1

Response

First ETOR is auto populated using the dispatch time. 75 minutes rounded up to the next 1/2 hour. For longer duration outages a study was done to estimate repairs times using a 2 year average for 85% of all long duration outages.

Historical data for automated estimate - Crew expertise for updated estimate when they arrive on the job and evaluate the work that must be done

We only used estimated restoration times provided by the crews who are doing or planning the work.

ETOR is currently a manual process at SCL. Primarily based on past experience and current conditions

already set parameters included in OMS and dispatch

Dispatcher judgement in consultation with or as dictated by crews.

Best guess

Historical estimations that are validate by responders on arrival.

Historical estimations that are validate by responders on arrival.

Automatic call and adjusted by dispatcher and power line maintainers

Outage System generated response times based upon historical data.

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22| WHAT STRATEGIES ARE USED TO MINIMIZE SCHEDULED INTERRUPTIONS? [E.G. MOBILE GENERATORS]

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q22.1

Response

Mobile generators for business, additional crews working on project, and prepping for job as much as possible ahead of time.

mobile generation.

Do as much work as possible 'hot'. Advanced discussions & agreements with commercial customer to plan the details of a planned outage. Crew has all 'pre-work' completed & materials & equipment at the work site before de-energizing. Switching is performed to minimize the number of customers affected. In some cases, bypasses may be run to avoid extended interruptions.

Team leaders monitor their work Queue's and coordinate repairs to minimize the number and length of outages.

mobile generators for long period interruptions, repairs on live lines with gloves and protections equipment

Live line work.

Hot work, temp. lines, loops

Planned interruption notification; mobile generation.

Planned interruption notification; mobile generation.

None

Work is performed energized where possible. Where this is not possible small individual generators are used where appropriate. Large generators have not typically been used for scheduled outages. Preparation work is done, when possible, ahead of the outage to minimize the duration of the outage.

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23| AVERAGE COST OF AN INTERRUPTION [NOT INCLUDING FINES OR PENALTIES]: COST TO CORRECT



Mean Quartile	
Mean	$1,490
Quartile 1	$1,149
Quartile 2:	$1,370
Quartile 3:	$1,772

Comments

Calculation used

Q23.2

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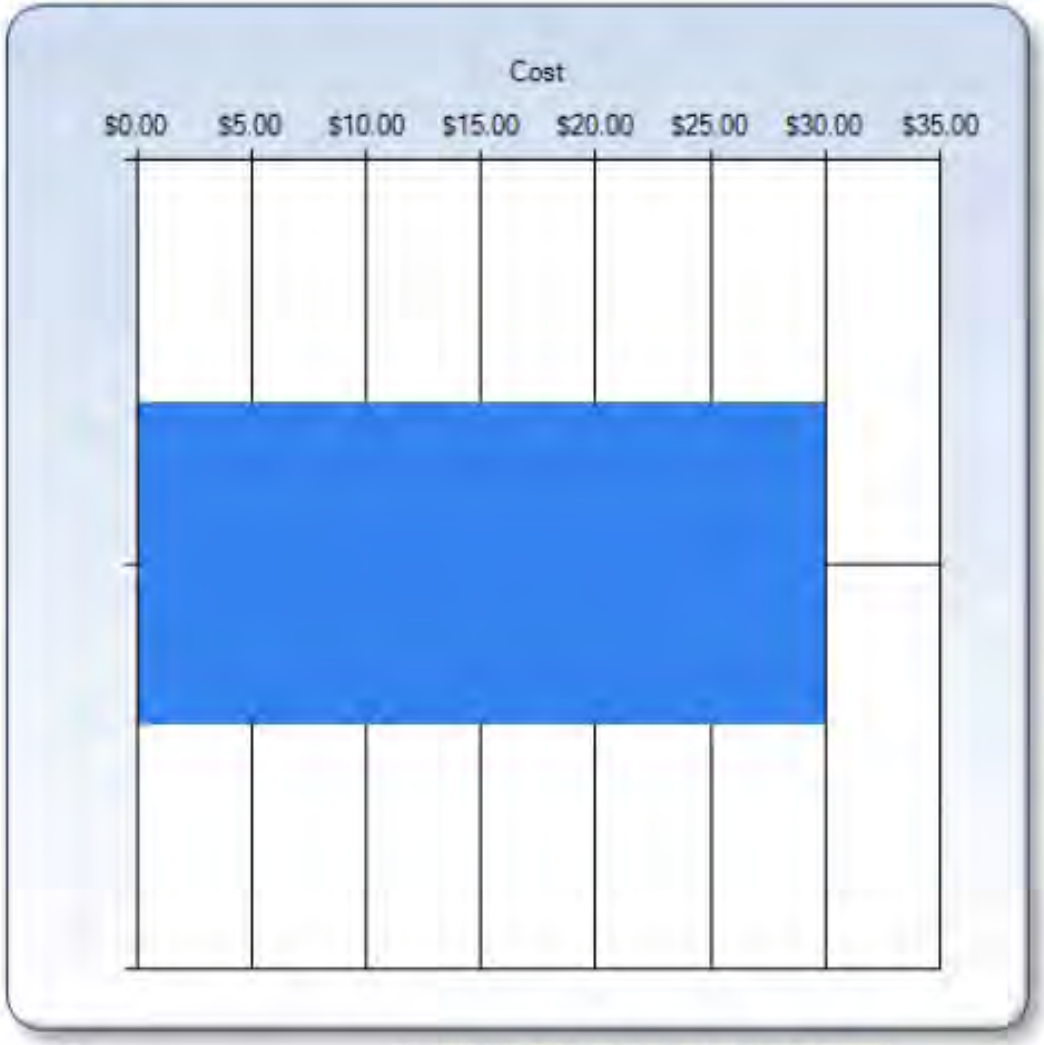
23| AVERAGE COST OF AN INTERRUPTION [NOT INCLUDING FINES OR PENALTIES]: COST TO PREVENT



Mean Quartile	
Mean	$30.00
Quartile 1	$30.00
Quartile 2:	$30.00
Quartile 3:	$30.00

Comments

Calculation used

Q23.1

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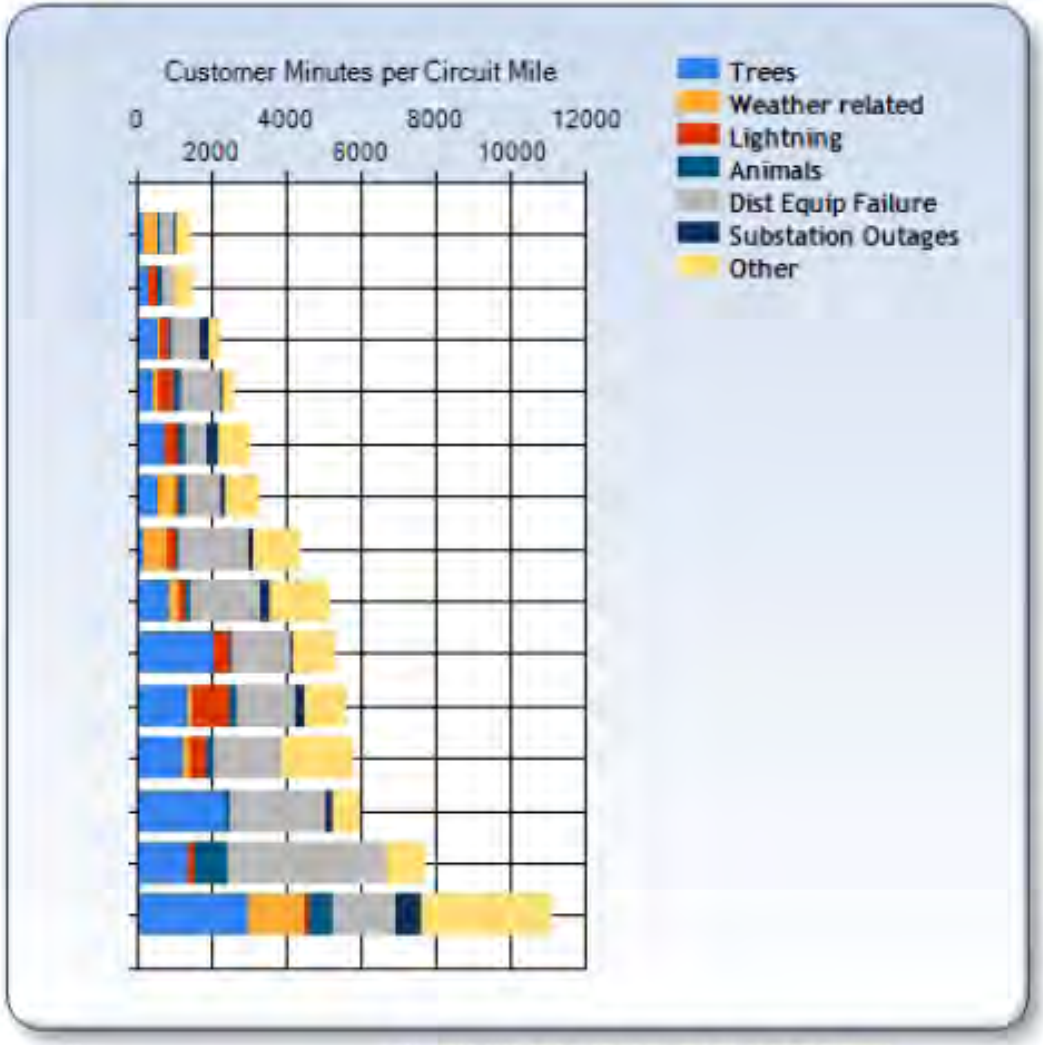
5| CUSTOMER MINUTES OF INTERRUPTION BY CAUSE PER CIRCUIT MILE (EXCLUDING EVENTS)



Mean Quartile	
Mean	4684
Quartile 1	2763
Quartile 2:	4775
Quartile 3:	5808

Comments

Calculation used

Q5.2A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.3A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.4A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.5A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.6A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.7A * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.11A * (T&D Dist End Use Customers) / (Dist Circ Miles)

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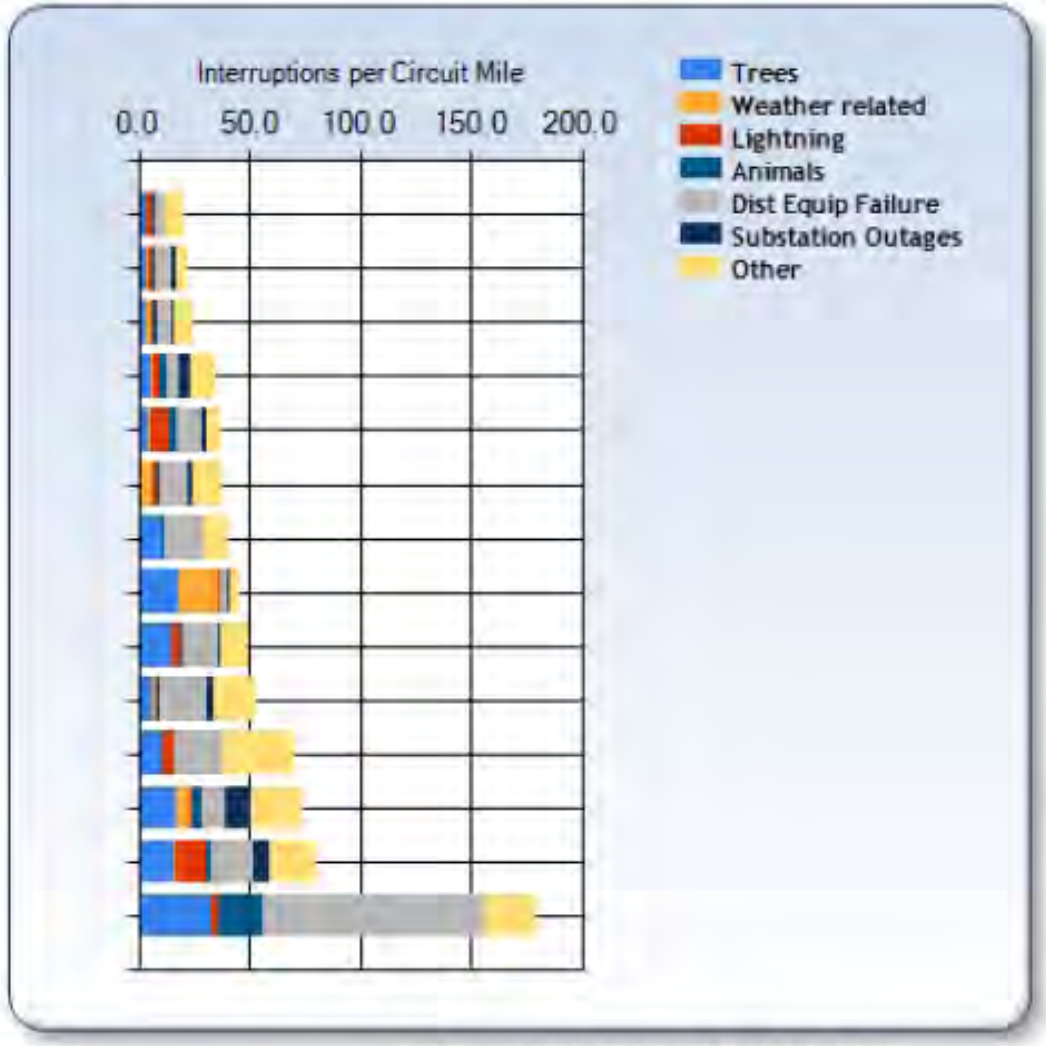
5| INTERRUPTIONS BY CAUSE PER CIRCUIT MILE (EXCLUDING EVENTS)



Mean Quartile	
Mean	55
Quartile 1	36
Quartile 2:	43
Quartile 3:	66

Comments

Calculation used

Q5.2B * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.3B * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.4B * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.5B * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.6B * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.7B * (T&D Dist End Use Customers) / (Dist Circ Miles), Q5.11B * (T&D Dist End Use Customers) / (Dist Circ Miles)

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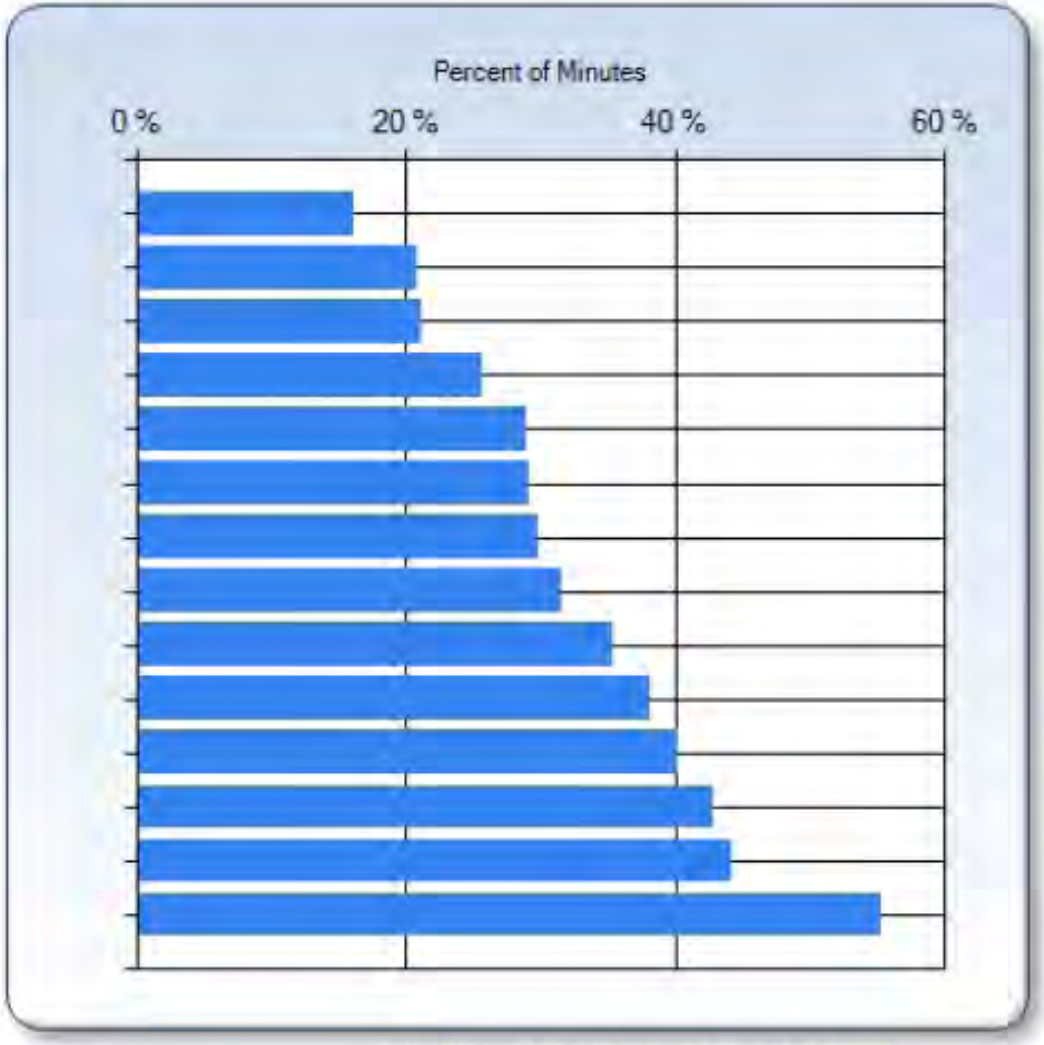
5| SAIDI EQUIPMENT FAILURES PERCENT OF MINUTES



Mean Quartile	
Mean	33 %
Quartile 1	26 %
Quartile 2:	31 %
Quartile 3:	40 %

Comments

Calculation used

Q5.6A / (Q5.5A + Q5.2A + Q5.3A + Q5.4A + Q5.6A + Q5.11A) * 100

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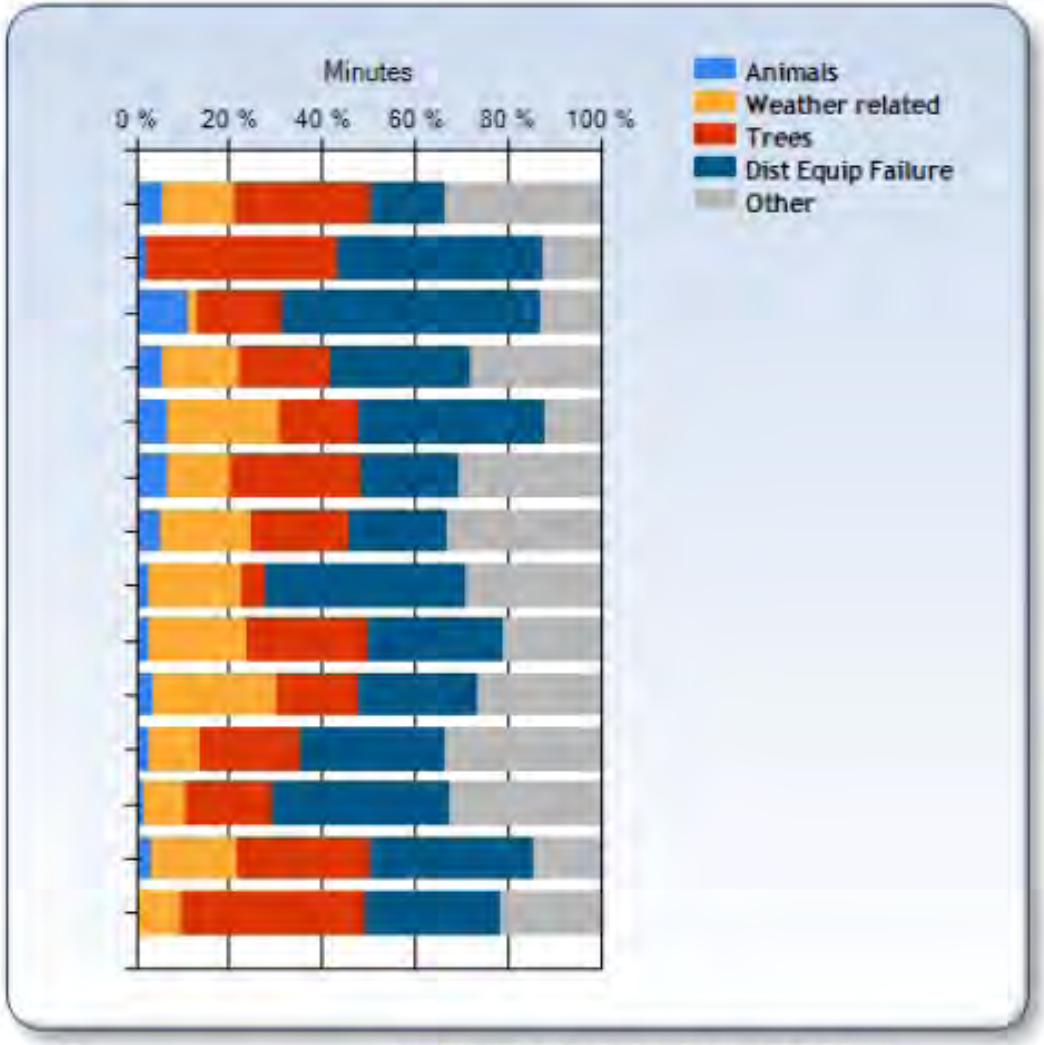
5| SAIDI PERCENT OF MINUTES BY CAUSE



Mean Quartile	
Mean	118 %
Quartile 1	113 %
Quartile 2:	104 %
Quartile 3:	77 %

Comments

Calculation used

Q5.5A, Q5.3A + Q5.4A, Q5.2A, Q5.6A, Q5.11A

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5| SAIFI EQUIPMENT FAILURE PERCENT OF OUTAGES



Mean Quartile	
Mean	30 %
Quartile 1	22 %
Quartile 2:	32 %
Quartile 3:	36 %

Comments

Calculation used

Q5.6B / (Q5.2B + Q5.3B + Q5.4B + Q5.5B + Q5.6B + Q5.11B) * 100

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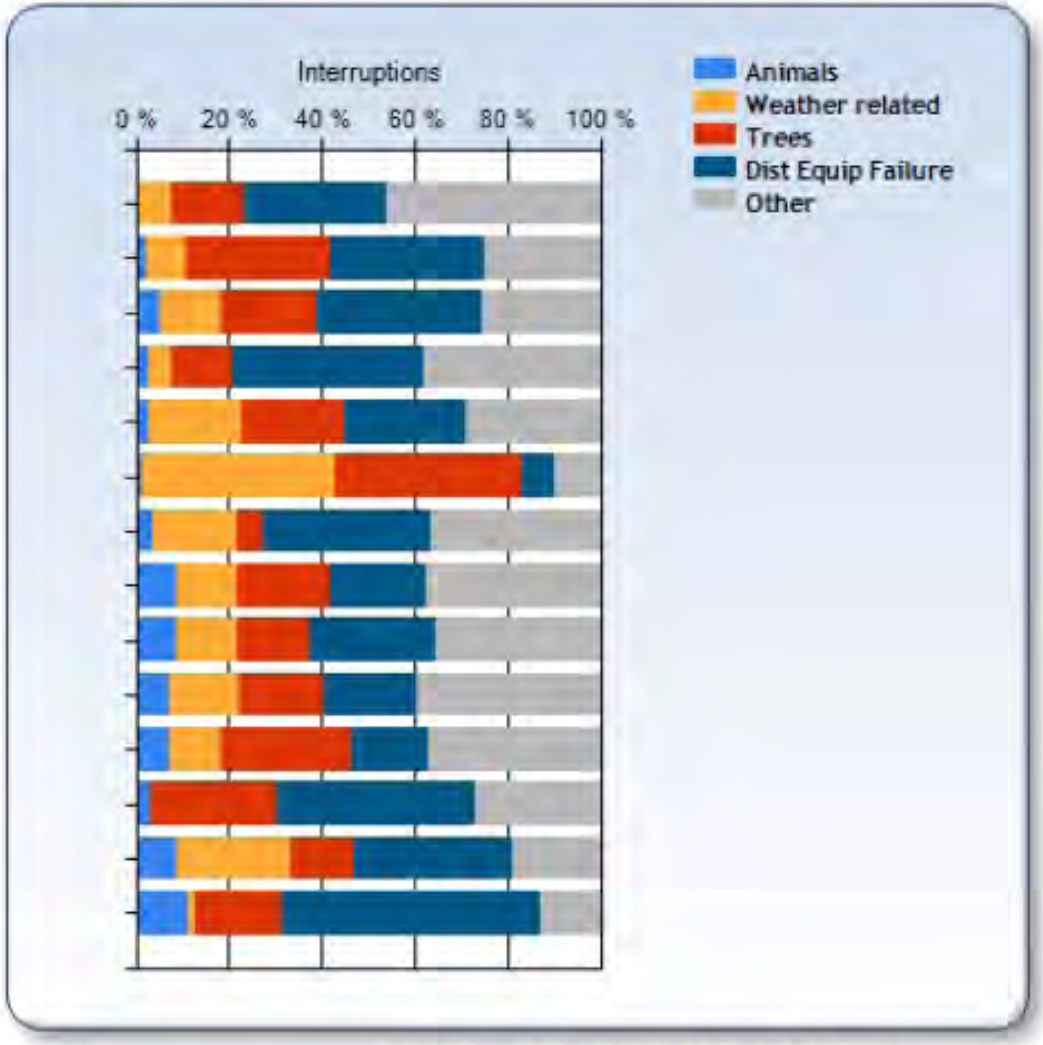
5| SAIFI STATISTICS PERCENT OF OUTAGES BY CAUSE



Comments

Calculation used

Q5.5B, Q5.3B + Q5.4B, Q5.2B, Q5.6B, Q5.11B

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Distribution

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2| What steps have you taken to introduce activity-based costing concepts?
3| What metrics do you use to measure budget performance?
4| Please describe any changes you have recently made in your overall strategy around planning [e.g. how far out into the future, detail level, etc]
5| Measuring the productivity levels of your distribution planning/engineering/design groups
6| What initiatives have you undertaken to improve the process from getting a job from planning to delivery?
7| What initiatives have you undertaken to change your engineering standards?
8| Benefits Asset Management approach has provided
9| Please describe your major distribution automation initiatives [Note: See section on Intelligent Grid]
10| Initiatives underway to improve the effectiveness of CADD
10| Initiatives underway to improve the effectiveness of GIS
10| Initiatives underway to improve the effectiveness of WMS
10| Initiatives underway to improve the effectiveness of Other
11| What initiatives do you have underway to improve job estimating?
12| What initiatives have been taken to encourage innovation?
13| What initiatives have you undertaken to encourage the use of cross-functional teams [e.g. How do you encourage cooperation with construction?]?
14| What initiatives have you undertaken to train new employees or upgrade existing skills?
15| Office facilities engineering/design personnel work out of
16| What practices are in place that have been successful for managing engineering documents?
17| What are the standards for new business [e.g. undergrounding]?
18| How do you schedule jobs to make sure the customer is ready?
19| What customer contributions are required [e.g. extension allowances]?
20| Customer contributions last year
21| What work is the developer required/allowed to perform?
22| What initiatives have you undertaken to improve the new business process?
23| If you are a combination E&G utility, how do you take advantage of synergies?
24| Do you have any joint trench programs with other utilities?
25| Facilities field personnel work out of

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26| Please describe the most important initiative underway to improve productivity of distribution construction?
27| Please describe the most important initiative underway to improve distribution maintenance practices?
28| Please describe the most important initiative underway to improve distribution restoration practices?
29| Practices/technologies/tools successfully used to improve maintenance on Transformers
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29| Practices/technologies/tools successfully used to improve maintenance on Cable
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31| What have you done to get the most out of your work management system?
32| How are you measuring field construction success?
33| How are you measuring the quality of the work performed by contractors for field construction?
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36| What major challenges - near and long term - are being faced by the field organization?
37| What initiatives do you have underway to promote cooperation with the union[s]?
38| What initiatives are underway to promote a safety culture [note: see safety section]?
39| Please describe any practices that have been successful for improving contractor management especially with regard to productivity?
40| Distribution dispatch centers
41| Please describe any changes in your dispatch centers in the last few years?
42| What initiatives have been undertaken to improve restoration efforts?
43| What have you done to get the most out of your outage management system?
44| Please describe how your outage management system interfaces with a mobile data system [if any]?
45| What major challenges - near and long term - is the dispatch center[s] facing?
46| What initiatives or practices are in place that have been successful in improving the dispatch function?
47| Trouble calls per End-Use Customer
48| Please describe how your outage management system groups trouble calls?
49| Technologies/tools/practices that have improved vegetation management: Chemical gowth inhibitors
49| Technologies/tools/practices that have improved vegetation management: Mechanical side trimmers
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50| Vegetation Management Expense per Trees Trimmed
50| Vegetation Management Expense per Trees Trimmed or Removed
50| Vegetation Management Expense per Trees Managed
50| Vegetation Management Expense per OH Structure Miles Managed

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50) Vegetation Management Expense per Trees Miles Managed

51) Continuum between proactive spending and reactive spending dependent upon available funds

52) How are you measuring vegetation management success?

53) What major challenges - near and long term - are being faced by vegetation management?

54) What initiatives or practices are in place that have been successful in improving vegetation management operations?

55) Practices used to determine the appropriate trade-off between purchase and repair of Meters

56) Practices used to determine the appropriate trade-off between purchase and repair of Transformers

55) Practices used to determine the appropriate trade-off between purchase and repair of Vehicles

56) What choices have you made regarding equipment repair capabilities [in-house vs. outsourced]?

57) Initiatives or practices in place that have been successful in improving fleet operations

58) Initiatives or practices in place that have been successful in improving meter shop operations?

59) Initiatives or practices in place that have been successful in improving transformer shop operations?

60) Initiatives or practices in place that have been successful in improving warehouse/materials operations?

61) Initiatives or practices in place that have been successful in improving IT operations?

63) J.D. Power Electric Utility Residential Customer Satisfaction Study: Overall score

63) J.D. Power Electric Utility Residential Customer Satisfaction Study: Power Quality & Reliability

63) J.D. Power Electric Utility Residential Customer Satisfaction Study: Company Image

63) J.D. Power Electric Utility Residential Customer Satisfaction Study: Price & Value

63) J.D. Power Electric Utility Residential Customer Satisfaction Study: Communications

64) Did you witness a change in overall customer satisfaction with regard to Customer Service last year?

65) What is your strategy to balance the trade-off between service levels and cost?

66) Please describe your process for managing the power system.

67) How are the activities of the dispatch centers integrated to the activities of the system control centers?

68) Automated lines at the distribution substation level

69) Average number of customers for each system control center

70) In what way data are updated in your power management system?

71) Please describe the process of a planned interruption?

72) Please describe the intervention process when there is an interruption?

73) What are the most important issues you have met in the past years? Did you carry out important changes during the last years in your system control center? If yes, what are they?

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1| WHAT INITIATIVES HAVE YOU UNDERTAKEN TO IMPROVE YOUR BUDGETING PROCESS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q1.1

Response

"Flex spend" budgets. Specific discretionary programs are identified which can be ramped up or ramped down during the year depending on the company's overall financial status.

All automated with easy to request on line & printable reports for cost center managers to use for evaluation of planned vs. actuals, with same flexibility of rollups for department managers and executives. Corporate KPMs keeping budget flat which encourages a very careful allotment of funds. Budget expenditures are part of the KPMs and annual bonuses and additional 401K matching if targets are met. This encourages all personnel to think of creative ways to accomplish a task at a lower cost.

We are implementing programmatic budgeting, beginning in the 2009-10 budget process

The company evolves in a regulated setting and the budgets allowed to the distribution service divison are determined at high level with very small breathing room and the main orientations given in a strict way. One of the most important part of the budgeting process involves the breakdown of the budget allowance through the different units forming the division. To obtain a better allocation of the resources and a greater equity between the units, a zero-base budget was initiated. Also, to tie the budget planning with the operations and obtain a better allocation of the financial resources, a model of evaluation of the work load and capacity was put in place. This model allows (with ratio based on historical data) to see what the budget of the unit should be according to the planned working load and therefore adjust it in link with the resources that are actually available. This model is used with the zero-base budget to make a better allocation the resources given to the division. Also, a detailed model for the planning of the paid personnel was use to obtain finer evaluation and control of the staff and the payroll. We also tried to work more closely with the units responsible to plan and supervise the units dedicated to realisation of the work so we can make a budget that reflects their preoccupations of all the units of the distribution service.

Plan reflects outcome of WorkForce Availability Study

We have assigned subject matter experts the task of writing strategy papers for the most appropriate options for funding certain work types. These strategy papers are then compiled and evaluated as a whole to understand overall funding options. Prioritization tools have been developed, although currently are not actively used.

Initiatives are undertaken to focus much more on "Execution" planning in conjunction with defining Asset Needs i.e. how to meet the needs of our assets over time. We do so with the recognition that the real and significant challenges of resourcing, materials, outages and

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approvals have served to inject, over the past few years, a lag in the execution of work relative to asset needs.

MidAmerican instituted a utility-wide Asset Management Improvement Process including re-engineering the budget submission process, introducing a tactical level to the asset planning process, introducing optimization routines at operational, tactical and strategic levels of the organization, establishing an MEC-wide framework and consistent basis for investment appraisal, rationalizing blanket authorizations in strategic/tactical programs, reviewing investment governance routines while specifically introducing post-investment appraisal at both project and driver levels, providing an executive overview of investment, incorporating platform level expenditures, risks and returns, insisting on a residual risk analysis as part of a sign-off of the corporate plan, and determining asset management organizational structure.

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2| WHAT STEPS HAVE YOU TAKEN TO INTRODUCE ACTIVITY-BASED COSTING CONCEPTS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q2.1

Response

Budget structure implemented in SAP system is activity/process oriented. We use the same high level work categories in our Work Management System so that we can correlate costs with work volumes.

Very little has been done on the Distribution side. This is mainly due to a lack of resources to devote to the process of learning what must be done. - Are able to calculate ABC for transmission & substation. They have members on their staff who were once in the Financial area and have been able to devote the time to learning the process. ABC for Distribution appears to be more complicated than for T&S.

We are currently introducing ABC concepts. The first step we took was to determine the activities we were going to include. They were chosen in link with the operational management system we actually possess (SAP PMPS). The direct cost of several activities (capital and maintenance) could be obtain through these systems and the activities they used to split those cost created a language known by most. So those activities (and the direct cost) served as basis and we added other activities and indirect costs to capture all the costs and operations of the division. After that, through SAP we defined the parameters to allocate the indirects costs to all the activities so we could obtain the full costs of each activity. To be sure we would use the right parameters (ratio) to allocate the indirect costs to the activities we meet with several managers to comprehended how each activities were related to the cost, specifically joints costs. Training was also given to all the managers of the division and the employees of the financial sector. Those training sessions were created to update everybody on the concepts and uses of ABC costing. Currently, we were able to obtain results at high level but system issues compel us to re-evaluate the project. Some of the analysis asked by the users require a high level of details and a flexibility that the system we used (SAP CO) could not attained.

Already in Place

cost / connect metrics are tracked and activity costing is tracked for inspections and some maintenance tasks

We plan and budget our work by activities within different line of businesses. These activities are then prioritized and estimated in line with the available resources.

MidAmerican established a utility-wide activity-based accounting process but found difficulties in converting the costs back to FERC-based accounting. After several years using the activity-based accounting, MEC ended the activity-based accounting and returned solely to the FERC-based accounting.

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3| WHAT METRICS DO YOU USE TO MEASURE BUDGET PERFORMANCE?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q3.1

Response
Variance to budget, variance to current target, variance to prior year
% of actual vs. planned expenditures
Over/Under budget, project by project
Unit Cost (in some areas)/ Actuals to Plan/ Cost Escalation Factors
variation of actual spent vs. budgeted on yearly basis - very little measurement at deliverable level
None
Capital expenditures are forecasted by each individual project on a monthly basis and compared to budget, which is reviewed by senior management. O&M costs are tracked by individual responsibility centers with monthly budget variance reporting.

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4| PLEASE DESCRIBE ANY CHANGES YOU HAVE RECENTLY MADE IN YOUR OVERALL STRATEGY AROUND PLANNING [E.G. HOW FAR OUT INTO THE FUTURE, DETAIL LEVEL, ETC]

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q4.1

Response

No recent changes

Load projections based off 'new' load data, especially for residential areas. CNP analyzes 'new' loads in relation to aggregate load diversity & / or non-coincidental loading at the circuit level w hen projecting new feeders and transformer additions. Withe energy conservation & more energy efficient construction, the aggreate load diversity has increased from a circuit load perspective.

Planning now looks out 2/6/10/20 year horizon

We have developed new tools to improve the effectiveness of the planning process: load transfer planning during outages and peak load validation/standardization

Account for entire life cycle through life cycle assessment studies for certain strategic business decisions.

Planning studies look 5 years to the future - longer equipment lead times have been recognized in planning project in service dates.

Traditional planning still done in a similar manner. More of a reliability focus through particular projects and an effort to accommodate advanced grid technologies and concepts.

None recently, individual distribution circuits are analyzed using Synergee softw are as needed.

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5| MEASURING THE PRODUCTIVITY LEVELS OF YOUR DISTRIBUTION PLANNING/ENGINEERING/DESIGN GROUPS

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q5.1

Response

No formal measurement of planning and engineering staff Designers are measured based on actual versus estimated design hours for specific job types and design cost per construction standard labor hours for specific job types

Annual Distribution Perfromance study with key metrics of: Recommended Capital Budget vs. Projected Demand Growth Redcommmended Capital budget versus Planned Capacity added Feeder & substation utilization factors

For planning : Percent of specific projects approved (for overload, automation or rebuild) For engineering and design : Percent of total cost of projects (projects abve 20 000$) and for small projects, hours required per customer demand treated.

Capital budget spending during the fiscal year and number of projects completed

Not measured directly in quantifiable terms.

Number of jobs designed by employee is reported from our Work Management System (WMS). Each area department manager measures productivity differently incorporating difficulty of jobs.

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6| WHAT INITIATIVES HAVE YOU UNDERTAKEN TO IMPROVE THE PROCESS FROM GETTING A JOB FROM PLANNING TO DELIVERY?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q6.1

Response

Central major project organization (handles both design & construction) works closely with planning to manage large system improvement projects from initiation to completion. Frequent progess review meetings are supported with detailed project management reporting and cost per mile metrics. Hve begun to apply a similar approach for system-wide inspection and maintenance programs.

Implemenation of a Web based system (DDPviewer) so all engineering, real time operations, & construction personnel have access to Planning data and initiatives for proposed capital improvements.

Capacity Plan developed since 2000, helps Planning implement goals.

Via our ERP system (SAP), we receive the clients' requests and inscribe it via the CRM module. The request is then forwarded to its responsible designer (via SAP). The scheduling is automated and may be modified if needed in order to comply with the requests' specific needs. At the completion of a task, when an activity is finished, this automated scheduling system let's subsequent teams or units that their implication is requested. All this managment is underlay with respect to the engagement we have with the client.

SPOT - Strategic Portfolio Optimization Tool - web based application replacing spreadsheets. Comprehensive project repoting. Work smoothing initiative. Field Operations forecasting and work planning. Increasing communication and work plan discussions. Annual planning meetings, system improvement capital project review and field visits. Resource allocation review and design process improvements.

centralized estimating and design of distribution projects. Have initiated some initiatives regarding centralized work planning.

Have increased the lead time between estimating and release for construction. Streamlined approval process by moving towards bulk program approvals rather than individual project approvals so that work can be released quickly.

WMS tracks work from inception to completion in step increments and reports progress to ensure that work is completed in a timely manner. Regular operations and engineering work load meetings are held to discuss all jobs being planned or worked, both system wide and at each of the local service centers.

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7| WHAT INITIATIVES HAVE YOU UNDERTAKEN TO CHANGE YOUR ENGINEERING STANDARDS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q7.1

Response

No recent major initiatives in this area. Standards are continuously reviewed and enchanced through the auspices of a cross-functional Standards Advisory Team.

Requested additional staff to support Asset Management initiative.

Our engineering standards are based upon the CSA (Canadian Standard Association) Norms. Internal HQ norms may be elaborated by our engineers but always have to respect the minimal standard dicted by the CSA.

Review of standards for compliance with Smart Grid vision.

Creation of a Standards Advisory Committee and Spec. Advisory Committee. Also have focused on optimizing cable design by implementing fluidized thermal backfills and fiberglass conduit.

Have recently completed a review of overhead and underground construction standards and are currently reviewing submarine cable construction standards.

The electric standards group performs audits of new business construction projects throughout the service territory. Standards are changed and improved through input from the field and feedback is given on adherence to standards.

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8| BENEFITS ASSET MANAGEMENT APPROACH HAS PROVIDED

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q8.1

Response

Major benefit has been a clear understanding of the condition of our infrastrucure and an orderly process for defining and prioritizing maintenance and system improvemment work across the entire system.

NA

Just intiating an asset management approach, thus benefits are not yet quantified

The Asset Management approach is currently being implemented and we expect better integration between maintenance practices and investment strategies (maintain or replace) A better standardization, prioritization of investments, accountability and risk management is also expected.

Life cycle approach (including C&M) for asset replacement decisions for aging infrastructure. Identification of the end of economic life of aging assets. Earlier replacement where economical, as well as work plan identification to better utilize constrained resources.

Development of detailed information on assets and gaining a better understanding of asset performance and impacts on reliability and costs

Separation of decision and action, central planning, expenditures are evaluated based on a set of consistent business drivers.

Discretionary capital projects are reviewed and analyzed by strategic investment, engineering, & critical property units risk management committees to ensure that any available funds are directed to highest value projects.

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9| PLEASE DESCRIBE YOUR MAJOR DISTRIBUTION AUTOMATION INITIATIVES [NOTE: SEE SECTION ON INTELLIGENT GRID]

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q9.1

Response

Implementing integrated distribution automation schemes to address reliability and capacity issues at the substation and feeder levels.

Small pilot at this time - Plan to approach PUC about larger project, but details not firm

Instaling S&C Scadamate switches in trial area for automatic sectionalizing and service restoration

1- Ongoing project of remote controlling one third of our distribution system (1000 feeders, 3750 feeder switches & breakers) up to 2013 2- Pilot project on Volt and Var control 3- Pilot project on Fault location based on waveshape analysis 4- Proposal on drive by AMR system under approbation

Province wide recloser initiative. Plans for province wide communications and inteligent metering - both enablers of future distribution automation: Smart Grid.

Distribution automation pilot and distributed storage pilot (battery).

Installation of DS Monitoring at major DSs, installation and remote control of LV sectionalizers

Automated capacitor control systems are currently being used. Automated switches have been installed on a trial basis.

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10| INITIATIVES UNDERWAY TO IMPROVE THE EFFECTIVENESS OF CADD

	Responses	Comments
Total Participants	18	
Number of Respondants	3	

Calculation used

Q10.2, 51542texttext

Response

Evaluating Design Tool software that would replace our current CADD software used by Designers and be fully integrated with our GIS and WMS.

Evaluating user training, customization and future upgrades of AutoCAD. New Title Blocks.

Implemented graphical based system design in 2003

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10| INITIATIVES UNDERWAY TO IMPROVE THE EFFECTIVENESS OF GIS

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q10.1

Response

Long term program to consolidate current separate gas and electric GIS systems and to eliminate/mechanize current manual interfaces to our OMS system.

Create models using CYME by extracting the latest data from GIS

2-year Technology Refresh project to migrate GIS software and applications for compatibility with other applications.

Veg/Tree info in reporting in GIS, outage info into GIS, IPP info in GIS. Providing consolidated relational represenation of GIS information and other information systems (such as outage data)

Yes

Our GIS system was implemented in 1999 and upgraded in 2005, with full connectivity from substation to meter.

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10| INITIATIVES UNDERWAY TO IMPROVE THE EFFECTIVENESS OF WMS

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q10.3

Response
Upgrading to latest version of WMS software; looking at options for replacing or significantly enhancing the scheduling and mobile data modules for long duration work
Initial phase of being designed (Part of Asset Management)
Working on developing some in-house work management tools to aid delivery
Yes
Upgraded in 2002 and incorporated with graphical based design in 2003

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10| INITIATIVES UNDERWAY TO IMPROVE THE EFFECTIVENESS OF OTHER

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q10.4

Response

Use single intergated system (ABB software) with a common geographic and electrical connectivity database for our OMS and short term planning programs (load flow analysis) We are continuing to enhance both through software upgrades.

Increase Remote Control & monitoring functionality of cap banks. Use OMS Graphical Switching to get real time circuit loading data based on the current circuit configuration. Use Web based system to improve communication and access fro delivery of proposed capital improvements.

Building engineering templates, new defined levels of service for easier to estimation

Planning tools:load transfer, peak load standardization

New Software

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11| WHAT INITIATIVES DO YOU HAVE UNDERWAY TO IMPROVE JOB ESTIMATING?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q11.1

Response

Using summer students in Industrial Engineering program to help update construction labor standards.

Benchmarking records help to ensure resources have been correctly estimated.

Updated Excel spreadsheets; spreadsheets for various levels of complexity

We have a Engineering Quality Program. We realize strict follow up on specific projects and carry out post-mortem activities in order to perform recommendations.

Annual review of high level unit cost estimation guidelines against historical estimates and actual spending. Contractor resource strategy. Early discussion on improving passport design estimation tool.

moved to centralized estimating staff for large subdivision and other large developments

Implemented graphical based design company wide. As a result, proposed facilities appear on maps for designers/crews. Also regular updates are made to the WMS system to reflect current costs for equipment, labor, loadings, etc.

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12| WHAT INITIATIVES HAVE BEEN TAKEN TO ENCOURAGE INNOVATION?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q12.1

Response

No formal initiatives.

On line regulated operations suggestion site allows employees to submit ideas (with or without identifying themselves). A committee must review and respond to the suggestion / idea within 30 days or less. Submittals & responses can be seen on line. More & more often, employees who actually do the work are asked to serve on committees to recommend a course of action to remedy a problem. These committees combine employees from each area or department that would be involved in the process or procedure. There recommendations are often very creative, low cost, and easy to implement.

Allow individuals to work in area of interest

A efficiency team was put in place in order to propose organizational and procedural improvements

Use of new technologies and equipments.

Innovative efficiencies are tracked and linked to possible bonus pay.

Formation of a small group with a focus on Advance Grid development.

Innovation is primarily fostered through a partnership with EPRI.

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13| WHAT INITIATIVES HAVE YOU UNDERTAKEN TO ENCOURAGE THE USE OF CROSS-FUNCTIONAL TEAMS [E.G. HOW DO YOU ENCOURAGE COOPERATION WITH CONSTRUCTION?]?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q13.1

Response

No formal initiatives but cross-functional teams are frequently used for special problem-solving or planning projects as well as standing committees scush as our Standards Advisory Team.

Business units are required to develop annual business plans to show how they will support corporate goals. Dependencies to complete their tasks are identified & others must have action plans to be sure they have the resources & meet the necessary requirements and deadlines. Weekly priority meetings within geographic territories include reps from all departments & divisions that are necessary to bring the job in on time, on budget, and in a safe, efficient manner.

Bi-monthly coordination meetings and monthly standards onte meetings with crews

We established a pilot project where the collaboration between the designing and the construction teams was proposed in the planification phase of the projects. This "team effort" was established in order to simplify communications and solve project specific questions regarding the design and construction aspects of specific projects.

Ongoing stakeholder engagement (MMBU, Community Relations etc.) for projects. Process improvements and increased communications.

Standards Advisory Committee

Assembly of cross functinal commitees or study teams to assess situations, suggest improvements, etc.

Cross-functional customer satisfaction teams have developed initiatives to improve timeliness of new service installations and improve customer contact. Also, Operations and engineering work load meetings are held regularly.

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14| WHAT INITIATIVES HAVE YOU UNDERTAKEN TO TRAIN NEW EMPLOYEES OR UPGRADE EXISTING SKILLS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q14.1

Response

Apprentice program for new designers;, college tuition refund program for all; engineeers are paid to attend various industry conferences and seminars.

Much emphasize is placed on annual Performance and Development Plans for individual employees. Cross training & know ledge transfer is often a Performance Goal of a tenured employee, w hile specific action plans for learning from a tenured employee will be on the employee development plan. Employees are also moved from one area of expertise to another more often to expose them to different sides of the business. CNP University is an elaborate on line training site that employees can use to sharpen their professional & personal skills in many areas.

Cross-training for new engineers; NESC Update training; conferences as appropraite

Furthermore to our established initial training program, w e have a netw ork of coaches and consellors distributed throughout our territories in order to answ er our employees' administrative, technical and contractual questions.

Development of Personal development plans.

enhanced in-house training programs and apprenticeship recruiting

Staff rotations; External and Internal courses;

Standardized gas and electric new technician training modules w ere implemented in 2006. Outside technical training is attended.

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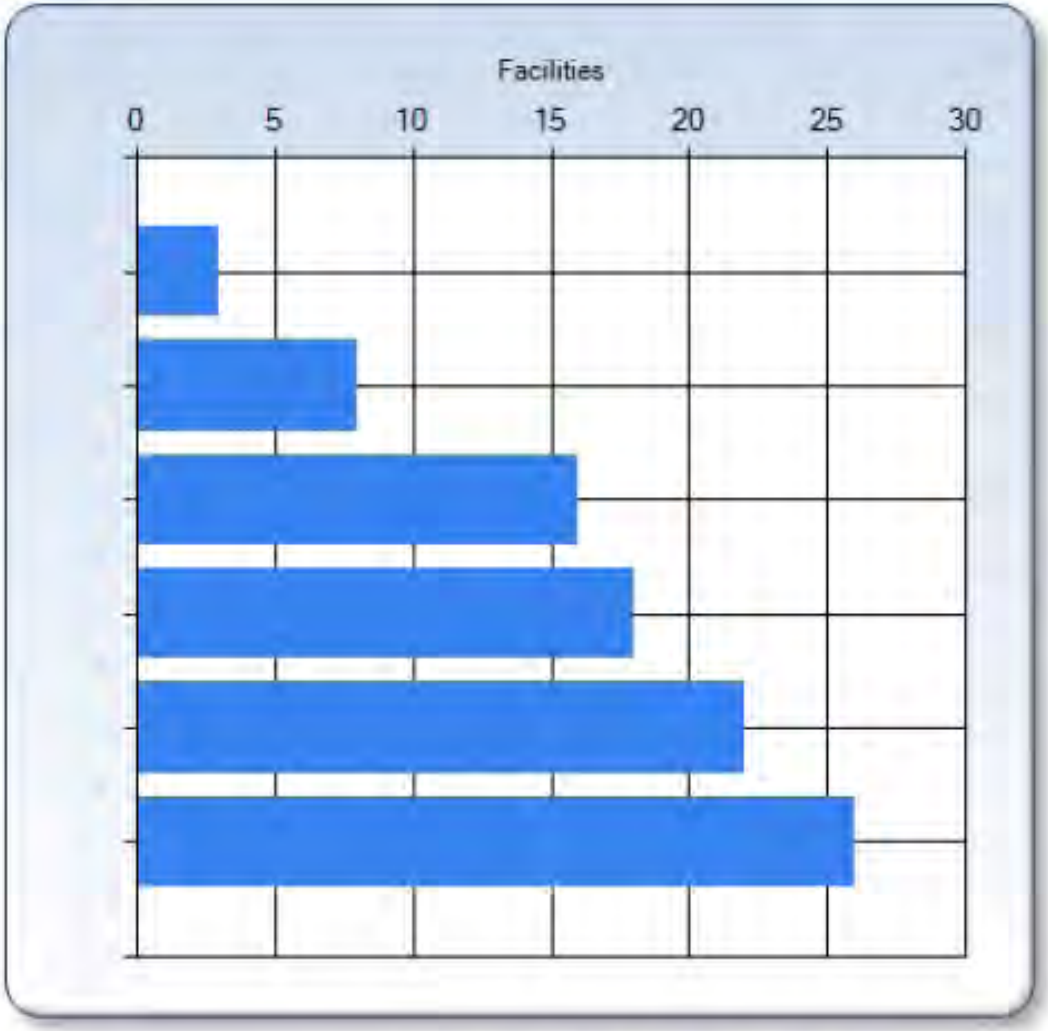
15| OFFICE FACILITIES ENGINEERING/DESIGN PERSONNEL WORK OUT OF



Comments

Calculation used

Q15.1

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16| WHAT PRACTICES ARE IN PLACE THAT HAVE BEEN SUCCESSFUL FOR MANAGING ENGINEERING DOCUMENTS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q16.1

Response

FAAR (Facility Access Automated Records) system provides on-line access to system maps. Available on desk-top computers and mobile computers. "Xpedio" software is used to manage standards and work procedures documents including tracking development and review process in some areas.

Electric Distribution Engineering maintains an Intranet website which contains a lot of information, plus links to other sites for instructions or documents for particular subjects / systems / standards.

Documents stored in shared drives and spreadsheets with document location.

We strictly work paper mode. Projects files are kept on site for a 2 year period. After 2 year delay, files are archived.

FileNet document management system

Electronic Document management system in place - primarily focused on drawing control.

A distribution net portal has been developed and is currently being used to manage documents.

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17| WHAT ARE THE STANDARDS FOR NEW BUSINESS [E.G. UNDERGROUNDING]?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q17.1

Response

New developments are typically built underground (Direct buried/URD) as this is the developers' preference and, in some cases there are municipal ordinances requiring us to build underground. Rates are set up based on the capital costs of an overhead distribution system so the develope or customer pays the additional cost up front as CIAC.

In "Requirements for Electric Serv Connection" document; more complex may be by policy

A customer can choose o/h or u/g with 2 exceptions when: the system is congested, we require u/g; or a municipality requires u/g.

There is an Electric Service Requirements Manual that is followed. We typically build overhead, unless agreements have been reached to provide underground. New subdivisions are built with underground cable.

Overhead construction.

Major feeder lines are primarily overhead and the lines within subdivisions are installed underground.

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18| HOW DO YOU SCHEDULE JOBS TO MAKE SURE THE CUSTOMER IS READY?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q18.1

Response

An initial target installation date is set based on the customer's planned construction schedule. We schedule and manage our design, right of way acquisition and permitting work so that is completed sufficiently ahead of the target date to enable efficient construction work scheduling (generally 3 weeks lead time). Proactive contacts are made with customer (or the customer's agent) to track activity and adjust target dates where appropriate. Customer or his agent sends us a "site ready card" when they are actually ready for service installation (site has been rough graded to within 4" of final grade). Service installation work is not scheduled until that card is received and we have also received notification of electrical inspection from the municipality.

Project Management Group works with customer. Receive orders from Retail Provider requesting service wanted date & then schedule when inspections completed & permit received.

No systematic way of scheduling jobs, except per customer request. Inspectors check compliance to requirments.

The information (availability date) is communicated to us via the permit submitted by the client's electrician. We plan our activity accordingly.

We release a job based on customer readiness (ie, the civil work is complete or permit(s) turned in.)

We have dedicated resources to do "site inspections" prior to a crew showing up to work a job

Jobs are scheduled using P3E. In addition, the customers responsibilities are communicted to him prior to the work we perform and we call the customer prior to coming to the site

Locations are checked regularly either by phone or drive-by prior to scheduling crews

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19| WHAT CUSTOMER CONTRIBUTIONS ARE REQUIRED [E.G. EXTENSION ALLOWANCES]?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q19.1

Response

Customer or developer pays for estimated design and construction costs in excess of an "embedded cost allowance" which equals the company's average capital investment per existing customer for electric line extensions and services.

Payment for all labor, material, and all resources necessary to build any extension that exceeds our set standards provided at no charge

Customer pays for service connection, requested line extensions and undergrounding

For every network extension exceding a certain distance there is a client contribution.

We require the customer to pay the full cost of the service connection (which serves them only), and BC Hydro will pay up to a maximum allowance on the extension costs based the average cost of asset investment per customer (which varies depending on the customer class).

Residential customers is a fixed rate ($1500 generally) industrial and commercial extension is based on estimated revenue

Contributions are based on the regulator's Dx System Code. Basically this is the cost of construction and maintenance less the present worth of future revenues.

Contributions are based upon tariffs and there are many variations to the contribution rules.

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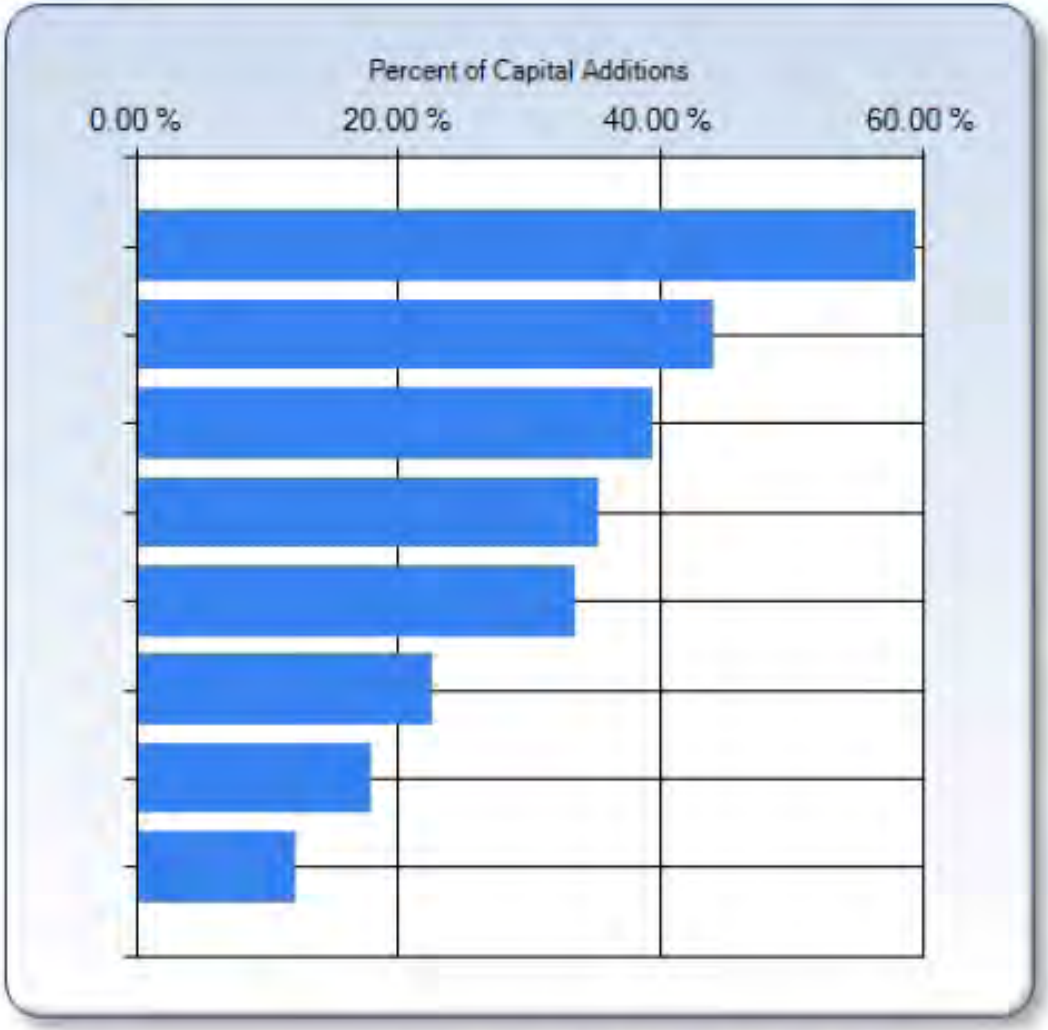
20| CUSTOMER CONTRIBUTIONS LAST YEAR



Mean Quartile	
Mean	33.12 %
Quartile 1	40.63 %
Quartile 2:	34.43 %
Quartile 3:	21.55 %

Comments

Calculation used

Q20.1 / Q9.1A * 100

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21| WHAT WORK IS THE DEVELOPER REQUIRED/ALLOWED TO PERFORM?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q21.1

Response

Meter socket installation (100%). Developer may install conduit for road crossings (minimal amount of work is handled this way.

Only to the installation of the meter can on OH - Installation up to meter can & installation of URD drops. ONP is responsible for connecting and energizing all drops & installing all meters

Common: Civil work for electrical service. Rare: Electrical work for service.

The developer may only realize the civil aspect of the construction under our supervision. The work realized must comply with our construction norms.

Civil work only

Typically the developer is in charge of digging trenches and installing conduit. All though we do have process for applicant built lines.

Contestable work (work not involving utility plant)

Developers are allowed to lay conduit to reduce costs and in rare instances they are allowed to bury service drops and then transfer ownership to the Company.

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22| WHAT INITIATIVES HAVE YOU UNDERTAKEN TO IMPROVE THE NEW BUSINESS PROCESS?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q22.1

Response

Template Designs and processes to expedite the completion of new service installations that do not require a custom design; Centralized division processes all service installation replacement and removal requests that do not require a custom design -- service centers handle only those that require a custom design. Also a centralized division handles all subdivision design and construction (electric and gas) work for multiple regions in the most populated area of our service franchise.

Created a Project Management Division. The customer works with a single contact from the start to finish of the job. That single contact handles all scheduling of resources & is responsible for issue resolution from start to finish.

Redesign of the new /revised service connection process to improve customer's experience.

Investigations into work segmentation and specialization; more formal training for the volume of new recruits; a simplified Tariff; consolidation of electric service connection work into 6 regional call centres.

We are constantly evaluating our communication with the customers to gauge effective process. This is why we have dedicated resources for customer contact.

The primary initiative is in the area of communicating with customers on construction schedules. Cross-functional work load meetings are used to determine if additional resources (contractors) are required to meet new business schedule requirements.

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23| IF YOU ARE A COMBINATION E&G UTILITY, HOW DO YOU TAKE ADVANTAGE OF SYNERGIES?

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q23.1

Response

Single contractor performs both electric and gas construction. We are also w orking w ith developers to gain acceptance of joint trench designs for gas and electric facilites to reduce costs.

Joint meter reading for move in / move out, coordination of joint trenching

N/A

n/a

Joint construction is used w henever practical for gas and electric extensions and services. There are instances w here foreign utilities are also included in joint trench. Our WMS and other systems use the same process for gas and electric.

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24| DO YOU HAVE ANY JOINT TRENCH PROGRAMS WITH OTHER UTILITIES?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q24.1

Response

Yes, with all telephone and cable TV utilities in our service territory plus a limited amount of joint gas-electric trenching with our own gas utility and other gas utilities that operate in our electric utility service footprint.

Yes

No formal programs yet

no

There are some programs in new large subdivisions with an emphasis placed on meeting and maintaining minimum clearances.

Yes

Yes, whenever possible.

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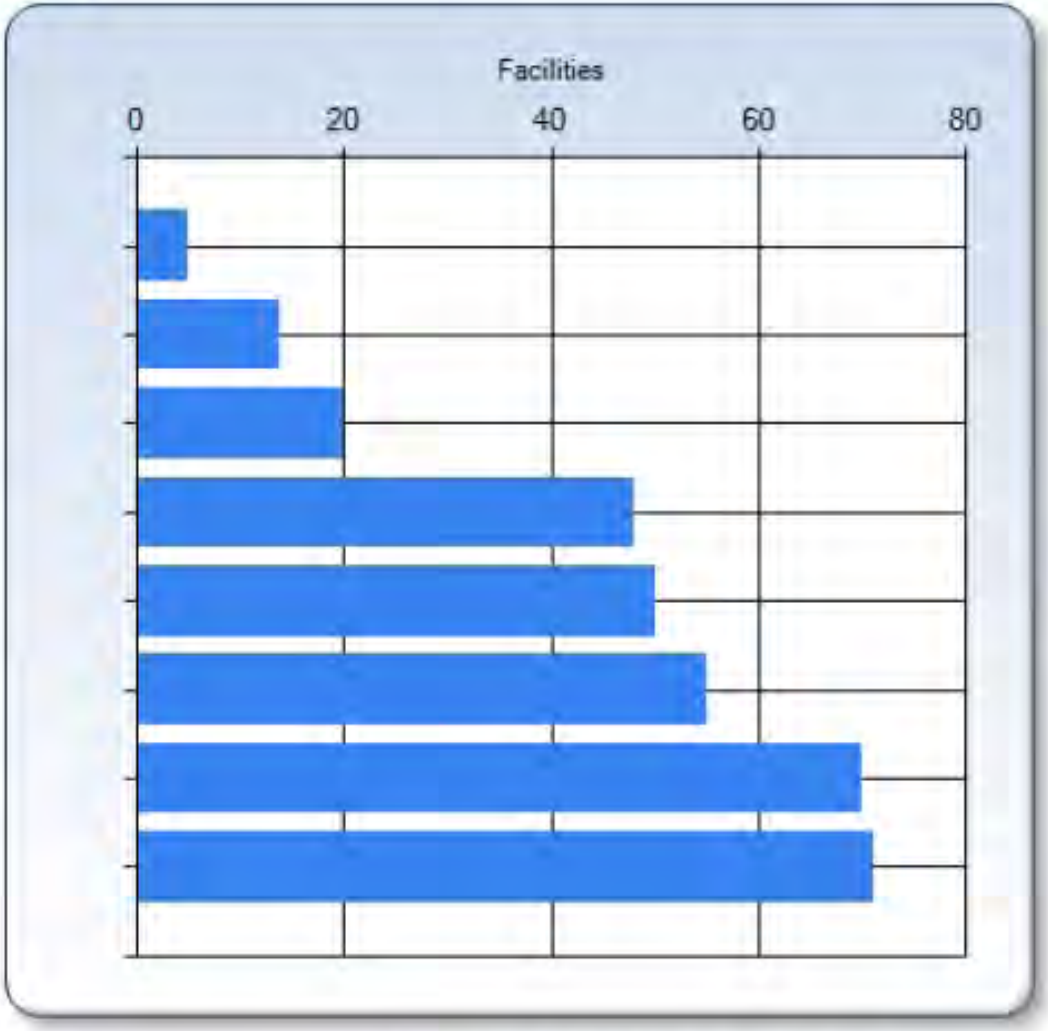
25| FACILITIES FIELD PERSONNEL WORK OUT OF



Comments

Calculation used

Q25.1

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26| PLEASE DESCRIBE THE MOST IMPORTANT INITIATIVE UNDERWAY TO IMPROVE PRODUCTIVITY OF DISTRIBUTION CONSTRUCTION?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q26.1

Response

Better productiticy measurement (we want to measure daily and at a crew level. Now we measure monthly at a service center/garage level)

Currently revieewing the possibility of an alliance with our construction contractors rather than our existing simple contractor arrangement.

Monotoring of all hours worked in a given period (year 2008 is a reference year) as well as the efficency of activities measures in Hours worked over hours earned, for the underground and aeriel distribution grids. Also the monitoring of the quality of work performed measured in number of non conformities as well as the cost of non quality. Finally, a province-wide effort to reduce administrative work for foremen so that they help their crews increase productive yard time.

Integrating work forecasting, scheduling and work allocation

We have created a Work Planning Department that queues up work for the district so that all the planning issues are fully resolved before construction begins. This allows the crews to have the right job at the right time with the right equipment and meter. Also, trailers with payout and retrieve for installing underground cable in a conduit.

BUNDLING OF DISTRIBUTION WORK THROUGH IMPROVED SCHEDULING

Increasing the number of directional boring crews.

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27| PLEASE DESCRIBE THE MOST IMPORTANT INITIATIVE UNDERWAY TO IMPROVE DISTRIBUTION MAINTENANCE PRACTICES?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q27.1

Response

Closer tracking and centralized management of field work associated with our key facility inspection and maintetance programs to ensure that all planned PM and CM tasks are completed as budgeted and scheduled.

Various new methods of controlling repeating worst performing circuits & predicting which circuits may hit the worst performing list if preventative steps are not taken

Started maintenance crew to target areas identified by business planning unit.

Pole's inspection program and deficiencies ranking program for repair are underway in 2008-2009 and centralizing maintenance optimization activities and strategies

Polymer Cut-outs

We have created a Work Planning Department that queues up work for the district so that all the planning issues are fully resolved before maintenance begins.

GIS ASSET MAPPING & ASSET INFORMATION DATABASE BUILDING ALONG WITH A NEW ENTERPRISE RESOURCE PLANNING SYSTEM

Not aware of any.

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28| PLEASE DESCRIBE THE MOST IMPORTANT INITIATIVE UNDERWAY TO IMPROVE DISTRIBUTION RESTORATION PRACTICES?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q28.1

Response

Planning to develop and install a new mobile data system for our line crews that will allow automated dispatch of outage/trouble work and streamline the crews' completion reporting. Currently we do have mobile data terminals in our troublehooter's trucks

Guarentee 4 hours of double time for any call out increases personnel to respond. Use of GPS to direct the closest qualified crew to respond to an order. Time of restoration goals set for lockouts and fuses / URD terminal poles. Each service center is monitored & monthly reports are published & openly displayed at each center. OMS sends message via MDS when trouble case is on a 10% worst performing circuit or a repeating worst performing circuit, indicating a need to make the case a high priority.

Purchasing an OMS system for improved future restoration.

Identify crews that will be called first and dispatched for restoration duties. These crews are paid a given amount of money to be on call.

Implementation of Resources on Demand Tool

Updating and verify our connectivity model to ensure accuracy with customer to transformer links.

ESTABLISHMENT OF IMPROVED STORM RESPONSE - USING FORWARD COMMAND POST

Staging crews in an area that may be hit by a storm.

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29| PRACTICES/TECHNOLOGIES/TOOLS SUCCESSFULLY USED TO IMPROVE MAINTENANCE ON TRANSFORMERS

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q29.2

Response
Only Stainless steel transformers in below grade installations
Underground : transfo oil analysis
cycle inspections
TRANSFORMER LOAD MANAGEMENT DATABASE
None

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29| PRACTICES/TECHNOLOGIES/TOOLS SUCCESSFULLY USED TO IMPROVE MAINTENANCE ON POLES

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q29.1

Response
Inpection prorgam targeted at older poles in areas where we have no plans to rebuild lines over the next 10+ years
Chemical treatment and butt wrapping of poles
Standardization of pole inspection method
Pole Test and Treat, cycle inspections
VARIOUS POLE TESTING METHODS TO INDICATE END OF LIFE
Inspections

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29| PRACTICES/TECHNOLOGIES/TOOLS SUCCESSFULLY USED TO IMPROVE MAINTENANCE ON CABLE

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q29.3

Response
Partial discharge testing to find bad splices and construction damage.
Distribution cable injection trial
Overhead : none; undergroud : better fault locating and cable injection
New fault locating devices. investigating cable injection technology
VISUAL, ELECTRICAL, TDR TESTING
New radar and thumper equipment

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29| PRACTICES/TECHNOLOGIES/TOOLS SUCCESSFULLY USED TO IMPROVE MAINTENANCE ON OTHER

	Responses	Comments
Total Participants	18	
Number of Respondants	2	

Calculation used

Q29.4

Response
tracking of fault data and consolidation of defects found during inspections into work packages
Rear lot line machines

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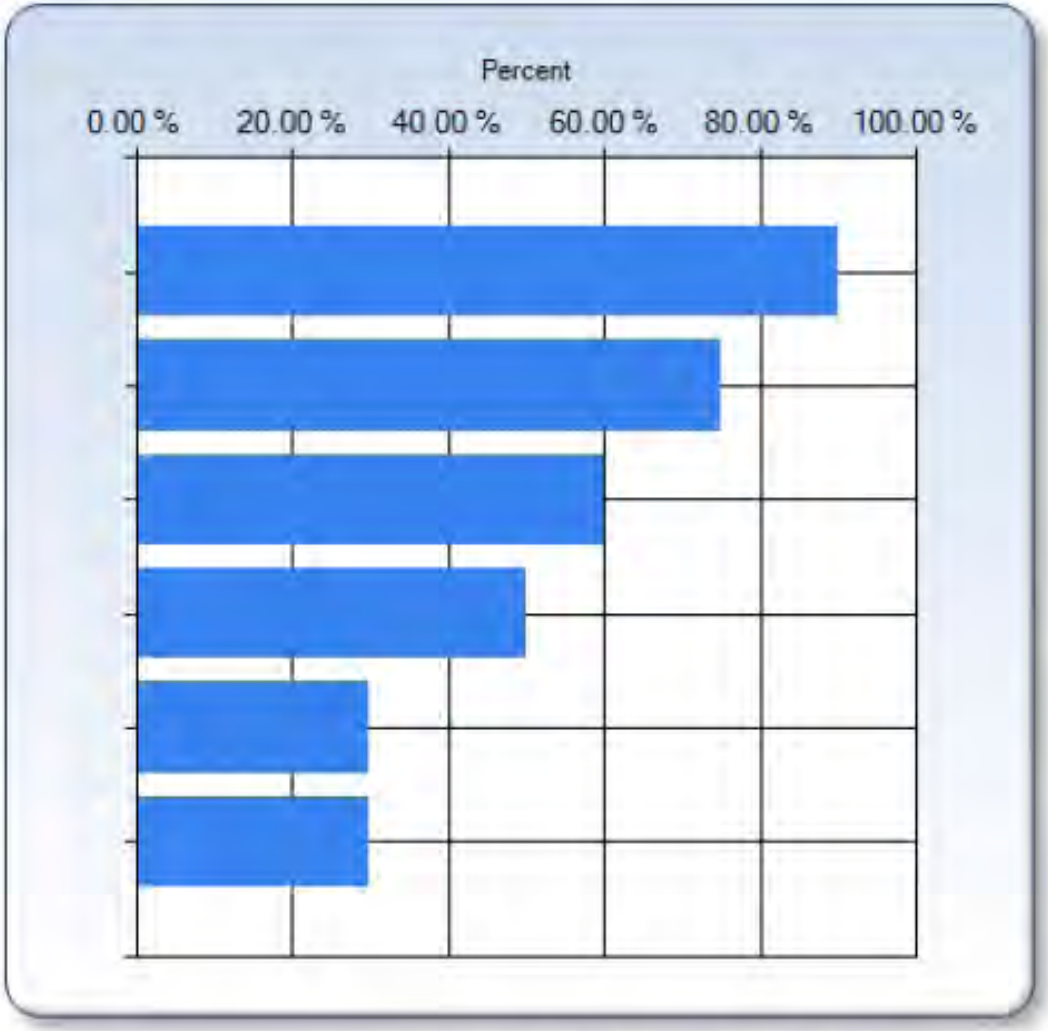
30| LINE WORK DONE WHILE THE LINE IS ENERGIZED [E.G. "HOT WORK"]



Mean Quartile

Mean	55.83 %
Quartile 1	71.25 %
Quartile 2:	55.00 %
Quartile 3:	35.00 %

Comments

Calculation used

Q30.1

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31| WHAT HAVE YOU DONE TO GET THE MOST OUT OF YOUR WORK MANAGEMENT SYSTEM?

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q31.1

Response

We have a central staff which "owns" the WMS and performs process and system deaign work on an ongoing basis to keep the system up to date with our needs

Blended the data from SAP with that from Mobile Data, The Business Warehouse, & other automated system to create reports and obtain information to assist in making more informed decisions.

Monitoring work load and allocating ressources on a priority basis, provincewide. Implementing a second-level planning unit (in every one of the 5 operating regions) to deal with local, regional issues

WEVE MADE THEM AVAILABLE TO MORE PEOPLE

N/A

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32| HOW ARE YOU MEASURING FIELD CONSTRUCTION SUCCESS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q32.1

Response

Performance Index which combines "Availability" (Total hours at work divided by total hours paid), "Effectiveness" (Total hours actually working on field jobs versus total hours at work) and "Productivity" (Actual hours charged to field jobs versus Compatoble Unit standard hours for those jobs). For larger line projects, we also have a "Cost Per Equivalent Mile" measure.

$ per foot for OH construction & $ per lot for URD construction Need date or date required by PUC met. Reliability indices after construction completed

Subjective evaluation by direct supervisor

As seen by Operations: execution of plans and within budget and performance objectives, achieving good performance pertaining to customer indicators, customer complaints, customer relations and all other performance indicators. As seen by the public: surveys, audits and public complaints, media etc.

Meeting in service dates and actual dollars vs. estimate

job completion and budget variance

COMPLETION & COST MONITORING & FIELD AUDITS

Compare estimate with actuals

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33| HOW ARE YOU MEASURING THE QUALITY OF THE WORK PERFORMED BY CONTRACTORS FOR FIELD CONSTRUCTION?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q33.1

Response

No formal measurement. Supervisors perform periodic field checks and fill out a form only when they observe unusually positive or negative construction workmanship or practices. We also have a central group that performs periodic audit of site conditions and also check pay paperwork. We are now adding staff to the latter area to tighten up our management of both quality and cost

Physical inspection. Perform 'post walks' for URD construction.

Measures quality by inspection of contractor work for adherence to design

Completing quality assurance audits on completed work & field Site Audits.

post-job completion audit

AUDITS

Crew Supervisors inspections

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34| HOW ARE YOU MEASURING FIELD MAINTENANCE SUCCESS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q34.1

Response
% completion of planned PM and CM work as budgeted and scheduled
Indices Goal dates met
Subjective evaluation by direct supervisor
quantity of the maintenance realized and $ spent
Meeting in service dates, quality of work completed and actual dollars vs. unit price
inspection volume, conditions resolved, and budget variance
AUDITS & RELIABILITY IMPROVEMENT MEASURES
Customer complaints

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35| HOW ARE YOU MEASURING FIELD OPERATIONS SUCCESS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q35.1

Response
Number of switching errors as % of total switching operation steps; % of switching jobs completed on time
Indices Need dates & required regulatory dates met
Subjective evaluation by direct supervisor
See question 32
Response time, cost per trouble call, estimated time of restoration customer satisfaction
response time, reliability, budget
RESPONSE TIME, SAFETY, CUSTOMER SATISFACTION, SYSTEM RELIABILITY & AVAILABILITY
Customer complaints

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36| WHAT MAJOR CHALLENGES - NEAR AND LONG TERM - ARE BEING FACED BY THE FIELD ORGANIZATION?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q36.1

Response

Continuing budget constraints. We have been directed maintain "flat budgets" (no adjustment for inflation) for all core business work since 2003 and this is expected to continue.

Aging workforce and knowledge transfer.

Merging of operations across two service centers and the sharing of those resources

Succession planning and hiring. Knowledge retention and transfer. Work force motivation. Succeeding in implementing major technological changes. i.e developing change management skills. Implementing a culture based on efficiency so as to maintain rate increases at or below inflation rates.

Loss of experienced workforce through attrition. Shortage of qualified Power Line Technicians creating contractor costs to sore. Survey

aging workforce and deteriorating assets

HIRING SKILLED STAFF, REGULATORY REQUIREMENTS & INTEGRATING NEW SYSTEMS AND TECHNOLOGY

Demands made by customers. Hours spent on training and meetings.

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37| WHAT INITIATIVES DO YOU HAVE UNDERWAY TO PROMOTE COOPERATION WITH THE UNION[S]?

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q37.1

Response

Union and company leadership meet monthly.During these meetings, company leadership informs the union of operating results and planned initiatives and union leadeship informs the company of any major concerns of their membership.

Open communications and support of initiatives brought by the union to management.

Constant communication with the various unions. Each one of our top manager has a responsibility to deal with a given union and proactively manage issues before they become major. The signing of 5 years collective bargaining contracts ahead of time is one sign of good cooperation between mamanegemnt and unions.

SUCCESSFUL CONTRACT NEGOTIATION

Union employees sit on a number of committees. More involvement

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38| WHAT INITIATIVES ARE UNDERWAY TO PROMOTE A SAFETY CULTURE [NOTE: SEE SAFETY SECTION]?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q38.1

Response

Safety Action teams (management and union) active in all areas; weekly safety conference calls which review all incidents and result in reports which are shared with all employees; developing improved safety leadership training for first line supervisors and union-represented crew leaders

Emphasizing safety at every Distribution meeting - Challenging employees to recognize safety is everyone's responsibility.

Grass Roots Safety Initiatives

Please see the section dealing with Safety

Safety by Design. Hazard Identification training and Qualified and Authorized Worker initiativetive

The recently formed Oncor Safety Council establishes a direct safety dialogue between representatives throughout Oncor Electric Delivery. The diverse group includes craft, technical, and exempt employees from many different responsibilities between field operations and the Chief Operating Officer.

constant communication regarding safety, safety meetings, safety processes, understanding that on all jobs safety comes first.

COMPLIANCE REVIEWS, MENTORING,FOCUSSED APPRENTICE TRAINING, INCIDENT REVIEW

Job Site reviews, one safety program

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39| PLEASE DESCRIBE ANY PRACTICES THAT HAVE BEEN SUCCESSFUL FOR IMPROVING CONTRACTOR MANAGEMENT ESPECIALLY WITH REGARD TO PRODUCTIVITY?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q39.1

Response

Most work is contracted on a fixed bid or unit price basis. When that is not practical, contractor is required to furnish detailed accounting of work performed and hours charged. This data is reviewed jointly by company and contractor management on a monthly basis. If there are productivity problems that the contractor cannot fix, we take back the work and/or assign it to a different contractor

A detailed review and justification of all contractor charges after construction including the strict interpretation of contractor units.

Distribution is just beginning a program to contract line work. We are in the lessons-learned phase

Pre-planned contractor use in such forms as firm bidding or unit bid has been our biggest improvement.

NONE

Inspectors in the field.

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40| DISTRIBUTION DISPATCH CENTERS



Comments

Calculation used

Q40.1

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41| PLEASE DESCRIBE ANY CHANGES IN YOUR DISPATCH CENTERS IN THE LAST FEW YEARS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q41.1

Response

Implemented mobile data/CAD in all dispatch centers and troubleshooter vehicles, remodeled all centers with ergo chairs and desks, use of ARCOS to call out crews.

No longer use static wall board for switching. Utilize on-line graphical switching & ordinary PC projectors

None

standard process with 911 control centers

Increased Emergency Contact role. Increased centralized dispatch during normal work hours.

In late 2005 and early 2006 the dispatch centers in XX and XX were remodeled. New working agreements were negotiated with the local unions that split dispatching responsibilities into three functional groups where previously there were two. The groups originally were outage coordinators and sub-transmission dispatchers. The new organization provides for outage coordinators, distribution dispatchers and sub-transmission dispatchers. The new organization also put in place a foreman/lead dispatcher for each of three areas the offices are divided into. The management structure was revised and support personnel for planning and protection were added to the organization. The fall of 2006 a new EMS/SCADA system was put into use by the centers. In the fall of 2007 a new outage management system was put into use by the centers.

Dispatch was centralized to the DCMc (Distribution Outage Management Centre) in 2000 in Markham and then moved to the OGCC in Barrie in November of 2003, in 2003 we also introduced an Outage Management System and Computer Assisted Dispatch function.

"The most significant change has been on staffing schedules and job assignments. There were four different classifications performing various functions in the control center. Each of the classifications rotated on a different scheduie and the shift supervisors did not have assigned reports. The legacy positions were: 1) Shift supervisor - responsible for the overall operation of the shift. 2) Distribution Operator - responsble for the real-time operation of the system and for restoration. 3) Dispatcher - responsible for single outages and transformer outages. 4) Communcations Technician - responsible for communications into and out of the control center. Teams were formed, an the dispatcher function was eliminated as it was limiting and not providing value for the FTE used. Each shift supervisor has two operators and a communications technician as direct reports so there is accountability. The teams rotate together so there are opportunities to form cohesive units within the control center."

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42| WHAT INITIATIVES HAVE BEEN UNDERTAKEN TO IMPROVE RESTORATION EFFORTS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q42.1

Response

First responders now make permanent repairs for 90% of all outages rather than calling in a crew.

Goal set & measured to decrease order received to dispatched time. Given controllers multiple automated tools that allow the dispatch of trouble orders and the creation and dispatching switching orders without leaving their seats. The greatest majority of data and tools needed are available at each workstation.

2007 Storm Response Initiative

stand by crew with pager out of the business hours

Creation of an Emergency Restoration Process group. Monthly operation meetings with Area Mgrs to drive process consistency.

Consistently pushed Field employees for accurate, and timely information. Call to assign, assign to arrive and arrive to complete targets have been set for outage restoration efforts. We also have goals to restore 85% of our outages within 3 hours. We have new processes when the number of outages exceed our day to day resource capability to restore outages timely. When the number of outages gets large due to an event, typically weather related, emergency action centers are opened to address resource issues.

Outage Management System, Computer Telephone Interface, Outage Review Team to respond to issues identified in high volume activities. Mobile Dispatch function being pilote din 2008, ICCP link between Network Management System and Outage Management Sytem to be deployed in 2008. Inter-Utility visits to compare best practices.

Periodic storm simulations take place to test processes and systems. After each storm an post-storm review meeting is also held and opportunities for improvement are identified. Improvements identified include issuing hand held GPS units to crews, improved communications between control center and storm centers, periodic coordination calls during storms, new wire watcher processes, automated call distributor for the control center, and sending trained control center operators to assist in the storm centers.

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43| WHAT HAVE YOU DONE TO GET THE MOST OUT OF YOUR OUTAGE MANAGEMENT SYSTEM?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q43.1

Response

We have tied it to our IVR system to call back after outages, we populate ETA's and ETR's, we interface with our outage reporting system to pre-populate information from mobile data and system operators.

Created multiple real time interfaces to different systems to pass & receive information needed to provide data needed by internal & external customers. Intranet access to view only information takes load off of systems used by controllers & crews to enter, receive, and update data needed for service restoration.

No automated OMS system

remote devices on grid

Customizations to match business processes. In house web interface for field users.

One-on-one training with Subtransmission Dispatchers, and continual follow-up for accuracy. We have just completed an upgrade to a newer version of the software that give us more flexibility in correcting the database.

Continuous process improvements, add on reporting and audit systems on weekly and monthly basis.

The outage system has been fully integrated with the inbound HVCA, customer service system, outbound interactive voice response unit, and SCADA. Additionally, all modules of the OMS are fully integrated including maintaining a real time model of the system. The OMS maps are updated each day from the company's GIS system. Further opportunities for improvement are constantly being evaluated. Additionally, we are very active in the vendor's OMS user group and help drive beneficial changes to the software.

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44| PLEASE DESCRIBE HOW YOUR OUTAGE MANAGEMENT SYSTEM INTERFACES WITH A MOBILE DATA SYSTEM [IF ANY]?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q44.1

Response

Mobile data has interfaces with our customer information system, our work management system, and our OMS.

MQ series interface transmits data to & from OMS to MDS. Data entered tranmits & posts within 8 seconds, allowing restoration data and ERT times to be used by internal personnel & IVRs.

N/A

microwave communication between OMS and mobile

OMS sends info automatically when dispatched (ie. Not done by mobile dispatch software). Trouble orders are stacked on the user terminals. Specific info is passed back and forth (ie. Status, completion, etc). Repair and situation information required to be completed on the mobile terminal before proceeding to next order.

We don't actively use a mobile data system.

Integrated product provided by CGI, to be deployed June-July 2008.

No defined interfaces exist.

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45| WHAT MAJOR CHALLENGES - NEAR AND LONG TERM - IS THE DISPATCH CENTER[S] FACING?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q45.1

Response

Staffing has been a challenge in the past 10 years. Still a concern moving forward due to the stress level of the job and rotating shifts.

Aging workforce & knowledge transfer

Recruiting and Retention; NERC Compliance

crew ageing, availbility of crew out of business hours

Attempts by other groups trying to impose business process changes. Business continuity planning. Communications. IT software and infrastructure maintenance and enhancements. Re-location. Relationship with crew service provider departments.

The biggest immediate challenge is the aging workforce - this is a near and long term issue. Another near term challenge is to continually improve the information listed in our outage management system. More people want quicker, more accurate information during the outage. This also means that the mapping system must continue to improve in its connectivity, which is an ongoing and ever present challenge.

Staff attrition, 80% of staff have less than 2 years in the business.

The near term challenge facing the control center is integrating a significant number of new personnel into the operation and providing meaningful and effective training while still maintaining performance standards. Long term challenges include operator retenton, aging work force, and the ability to attract qualified applicants fto fill shift work positions.

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46| WHAT INITIATIVES OR PRACTICES ARE IN PLACE THAT HAVE BEEN SUCCESSFUL IN IMPROVING THE DISPATCH FUNCTION?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q46.1

Response

Upgrading procedures, new training program, more support for the operating areas, higher troubleshooter staffing levels.

Appoint dispatching staff to committees to come up with recommendations for how to improve processes, come up with creative, low cost solutions to problems, etc. Committee then brings their recommendation to Management. Involvement in the process makes acceptance of the change much easier.

N/A

proactive climate event outlook to fasten the mobilization of crews

Process documentation. Worker training. Department structure and management - dispatcher relationship practices. Crew callout program

Standard switching terminology, EMS display standards, daily COMPASS coordination review meetings, minimum of 72 hours notice for all switching requests, switching procedures require 4 signatures (dispatcher, peer, relay, planning) before it can be executed, increased data quality and quantity in CADPOS (amp reading, fault locations, tags).

Regular audits and identification of training issues on weekly/monthly basis. Core training including field visits, specialized training, mock storms with field staff conducted 4 times per year (3 day sessions). Modified IVR systems for inbound calls that "communicate" with OMS and provide most current info to customers, reduces inbound tickets in high volume times.

Staff meetings to improve information flow, reorganization of operation along team lines, formalized shift change protocals, internal switching audits, reducing parasitic workload on operators, common internal switching protocals, and implementation of the automated call distributor.

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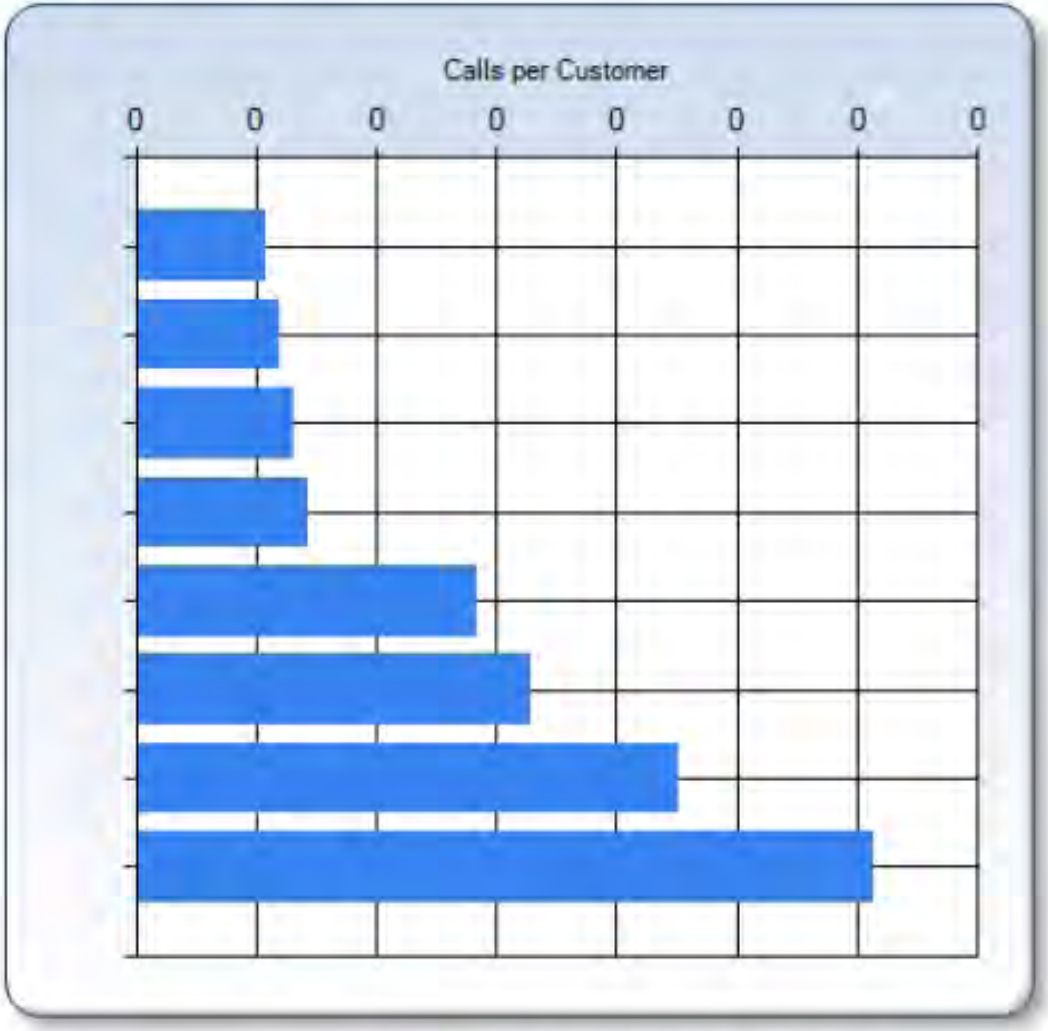
47| TROUBLE CALLS PER END-USE CUSTOMER



Comments

Calculation used

Q47.1 / (T&D Dist End Use Customers)

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48| PLEASE DESCRIBE HOW YOUR OUTAGE MANAGEMENT SYSTEM GROUPS TROUBLE CALLS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q48.1

Response

We use ABB CADOPS and it groups by transformer, device (switch), mid line recloser, station breaker. Each device level outage needs to meet certain criteria before rolling up to the next device.

Automated interface to EMS pushes lockout data to OMS to localize orders behind the lockout case. 2 calls behind a fuse, but on different transformers localize to the common fuse. 2 calls on a single transformer localize to a transformer outage.

N/A

when 2 trouble calls on same line, dispatch to nearest protection device

Trouble calls are grouped by call reasons and priorities

The outage management system will group calls to a probable device depending on how the calls come in from the customers. However, the dispatcher must validate the device as being out before it is actually verified within the outage system. Although the outage management system has 'smart technology' behind it, the dispatcher still relies on verification from the response man. The new version of our outage management system allows for the dispatcher to individually group calls using a master group feature. This keeps the call screens more organized while waiting for field verification of outage devices

The OMS is an analytical tool that looks up/down stream devices and predicts the affected devices group related calls into unique incidents. there are also capabilities to perform automated callbacks to determine "nested" outages. Dispatchers can create "quick incidents" allow dispatches on discussion with Transmission Controllers to open a device prior to a flood of calls.

All meters are connected to a transformer. The grouping percentages on a transformer are set at 2 calls or 100% of the customers on that transformer whichever is lower. Based upon grouping percentages for protective devices the number of downstream devices with customer calls drives the grouping managers to identify the most likely protective device that is trioped. Each new call is analyzed to see if it is part of a new incident, an ongoing incident, or if it goes past the grouping percentages set to move it to a new upstream device.

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49| TECHNOLOGIES/TOOLS/PRACTICES THAT HAVE IMPROVED VEGETATION MANAGEMENT: CHEMICAL GOWTH INHIBITORS

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q49.1

Response
Not used
None
Not used
n/a
Not licensed in Canada
Past limited studies to look at effectiveness of chemical growth inhibitors have shown mixed results.
We have extensive experience with tree growth inhibitors. We have been systematically applying them to fast-growing trees (cycle busters), with the idea of getting them to hold until the next scheduled cycles. This work has been underway for ten years, and has reduced the amount of off-cycle work on the system.
not used - not registered for use in Ontario
Not used often on distribution

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49| TECHNOLOGIES/TOOLS/PRACTICES THAT HAVE IMPROVED VEGETATION MANAGEMENT: MECHANICAL SIDE TRIMMERS

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q49.2

Response

Not used

Use of mechanized trimmers & Brown Tree cutters in rural, non-residential areas has significantly reduced trimming cost per mile and per tree in the areas we believe are appropriate for use. The Brown Tree Cutter, in addition to improving access for distribution linemen to off road easements allows for mulching limbs & brush on site, which reduces costs for disposal and recycles nutrients on site.

Not used

New technology : Impact on vegetation management not available yet

Not used - for Distribution

This is a cost effectivemethod to achieve clearances when compaired to manual/areial lift work.

We have used side "trimmers" on remote areas, particularly on conifers.

limited use. When used, used mostly in restriced to remote off road RofW sections away from general public view. Does not provide tree pruning that meets good tree care practices criteria

Not used often

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49| TECHNOLOGIES/TOOLS/PRACTICES THAT HAVE IMPROVED VEGETATION MANAGEMENT: OTHER

	Responses	Comments
Total Participants	18	
Number of Respondants	4	

Calculation used

Q49.1

Response
Improvement seen due to backyard lifts, priority based cycles, and unequipped small climbing crews.
None
Slashing instead of pruning
Inventory & Work Management IT tool

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50| VEGETATION MANAGEMENT EXPENSE PER TREES TRIMMED



Mean Quartile	
Mean	$126.40
Quartile 1	$45.32
Quartile 2:	$51.79
Quartile 3:	$221.96

Comments

Calculation used

Q12.3A / Q50.2

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50| VEGETATION MANAGEMENT EXPENSE PER TREES TRIMMED OR REMOVED



Mean Quartile	
Mean	$376.07
Quartile 1	$25.67
Quartile 2:	$76.57
Quartile 3:	$224.95

Comments

Calculation used

Q12.3A / (Q50.2 + Q50.3)

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50| VEGETATION MANAGEMENT EXPENSE PER TREES MANAGED



Mean Quartile	
Mean	$34.18
Quartile 1	$3.64
Quartile 2:	$6.65
Quartile 3:	$37.19

Comments

Calculation used

Q12.3A / Q50.1

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50| VEGETATION MANAGEMENT EXPENSE PER OH STRUCTURE MILES MANAGED



Mean Quartile	
Mean	$7,445.15
Quartile 1	$1,788.49
Quartile 2:	$3,519.07
Quartile 3:	$6,408.10

Comments

Calculation used

Q12.3A / Q50.5

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50| VEGETATION MANAGEMENT EXPENSE PER TREES MILES MANAGED



Mean Quartile	
Mean	$1,520.92
Quartile 1	$688.80
Quartile 2:	$1,133.67
Quartile 3:	$1,506.27

Comments

Calculation used

Q12.3A / Q50.4

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51| CONTINUUM BETWEEN PROACTIVE SPENDING AND REACTIVE SPENDING DEPENDENT UPON AVAILABLE FUNDS

Total Respondents	9
Target small areas or single trees as needed	0%
Target large areas as needed	33.33%
Varies by area	22.22%
Keeping with the growth rates in most areas	11.11%
Ahead of the growth rates in most areas	33.33%

Comments

Calculation used

Q51.1, Q51.2, Q51.3, Q51.4, Q51.5

Legends									
Target small areas or single trees as needed									
Target large areas as needed					♦	♦	♦		
Varies by area			♦					♦	
Keeping with the growth rates in most areas		♦							
Ahead of the growth rates in most areas	♦			♦					♦

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52| HOW ARE YOU MEASURING VEGETATION MANAGEMENT SUCCESS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q52.1

Response

Vegetation related SAIFI, Vegetation related customer interruptions.

Trimmed vs. Planned. Cost per mile. Completion of trimming 10% worst circuits by 4/3/08. Postive influence on 10% worst performing circuits and overall SAIDI improvement

Line miles trimmed

Respect of tree trimming cycle according to vegetation density and type along the feeders Pruning average cost, slashing average cost

Tree related outages

Tree SAIDI and SAIFI

Man-hours a line mile and man-hour a tree

tree caused outage statistics through SAIDI and SAIFI, accomplishment vs maintenance cycle expectations

Budget / maintaining 3 year cycle / complaints / compliments / CAIDI / SAIDI / preventative tree outages

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53| WHAT MAJOR CHALLENGES - NEAR AND LONG TERM - ARE BEING FACED BY VEGETATION MANAGEMENT?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q53.1

Response

Adequate funding, escalating labor costs.

Appropriate & inconsistant funding. Aging workforce issues are also affecting the Contract Workforce. It is becoming harder to finad & cultivate qualified tree trimming personnel. First generation immigrant workers pose a challenge with effective communication about their work with the public and our own staff. Public resistance to herbicides and herbacide price increases are affecting the valuable tool for intergrated vegetation management. With access to the Internet, the public is becoming increasingly knowledgeable & resistant to line clearance issues as they realize what methods are used in other areas. Utilities do not have a consistant and common national message to support local vegetation management programs.

Restarted tree trimming recently. Mixed public support. Resistance to particular tree trims.

Labor availability, climate change and growing rates. Integration of the activity to SAP

Mountain Pine Beetle infestation

NERC standards, State Regulatory issues.

Compliance with clearance requirements in California and Oregon.

near term -- funding levels, forestry staffing shortages, hiring and training of forestry trades staff, additional work to help "catch up" for poor vegetation management decisions in past (both on brush control programs regarding deferred cutting & a herbicide moritorium in the 1990's and line clearing regarding the allowing of ingrowth on single phase line over a 4 year stretch 1999 to 2004)

Transmission line ROW clearing and budgets

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54| WHAT INITIATIVES OR PRACTICES ARE IN PLACE THAT HAVE BEEN SUCCESSFUL IN IMPROVING VEGETATION MANAGEMENT OPERATIONS?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q54.1

Response

Incentive based contract and priority based cycles.

Active, positive executive management support. Adequate in house staffing (currently 1 supervisor & 9 forestors to deal with contracted vegetation vendors). Adequate contractor competition. Fixed price circuit trim awarded on demonstrated performance as well as pricing. Increased utilization of Corporate Communication Staff to develop internal and external vegetation management messages.

Management commitment to 4 yr tree trim cycle

Documentation, uniformisation of practices, slashing instead of pruning

IT programsd for inventory & work management- Best Practices standards.

Increased use of herbicides. Going away from T&M pricing methodology.

We have an incentive program, which rewards contractors financially for beating key performance indicators, and penalizes them for not meeting them. One of the most important factors in productivity as measured in both man-hours a mile and man-hours a tree. Also included are safety, work quality, customer service and the number of certified arborists.

use of a forestry technician staffing level to provide tree assessment, job planning & layout and customer contact

Multiple notification of impacted customers / mail / voice / in person

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55| PRACTICES USED TO DETERMINE THE APPROPRIATE TRADE-OFF BETWEEN PURCHASE AND REPAIR OF METERS

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q55.2

Response

Guidelines for fixing verus repairing traditional rotary meters are based on our long term experience. We are on a learning curve with AMR meters and register components and are hadnling this mostly through life cycle managemtn contracts with vendors

CNP does not repair meters. Meters in good working condition are re-certified and returned to service.

Meters are not repaired in-house; only warrantee work

Unable to answer - Electric Meter Shop?

Purchase cost vs. repair and asset life.

"It has been MidAmerican practice since 1995 to treat all three phase electromechanical meters as obsolete and not repairable. It has been MidAmerican practice since 2003 to treat all single phase electromechanical meters as obsolete and not repairable. These practices are based on the following: I. Cost comparison between new solid-state meters and repair of old electromechanical meters favors purchasing new solid-state meters. II. Solid-state demand meters are much more accurate than electromechanical demand meters. III. Electromechanical meters and parts are no longer available in most sizes and make repair expensive and not always possible. IV. Solid-state meters have a lower starting energy requirement allowing them to measure lighter loads. V. Solid-state meters are mult-form and multi-voltage leading to fewer types of meters needed for inventory. VI. Solid-state meters do not have moving parts making them less subject to dust, dirt, and tamper problems. MidAmerican does not repair solid-state meters. The meters can only be repaired at the factory. Only meters under warranty are cost effective to repair and returned to the factory."

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55| PRACTICES USED TO DETERMINE THE APPROPRIATE TRADE-OFF BETWEEN PURCHASE AND REPAIR OF TRANSFORMERS

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q55.3

Response

Guidelines for fixing versus repairing csitribution transformers are based on our long term experience.

Transformer shop outsouroed

Repair until 65-75% cost of replacement

Principally core steel quality combined with cost of repair

Our repairs constitute <10% of our annual usage. We only repair where we can get the best bang for the buck. Nothing over 20yrs old. they need to meet current standards, and be able to be repaired for less then half the moving average cost of new.

"There is no formal repair vs. replace criteria for transformers. Transformer repairs are made on a case by case basis. MEC has limited repair capabilities and resources. We have one shop that is certified by the manufacture to perform warranty repairs. Other than that only minor repairs are completed. Some basic questions ask before determining if a unit is to be repaired are: 1) Is the PCB level less than 50 ppm? 2) Is the unit newer than 1980? 3) Is the unit free of major structural defects, such as dents or significant corrosion? 4) Are the defects limited to minor repairs such as bushing replacement vs. internal windings and circuitry problems? 5) Is the unit three phase or unique to the specific local system? If the answers to the above questions are yes, repairs may be made on the units."

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55| PRACTICES USED TO DETERMINE THE APPROPRIATE TRADE-OFF BETWEEN PURCHASE AND REPAIR OF VEHICLES

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q55.1

Response

Analysis of historical maintenance data to optimize replacement cycles; becnhmarking costs and replacement cyles with other utilities.

Complete vehicle evaluation which includes age, mileage, maintenance history, and overall condition.

Repair until 50% cost of replacement

Life cycle cost analysis and reliability centered maintenance

Lifecycle analysis criteria using National Association of Fleet Administrators model.

We use a variety of KPI's such as average cost per km(age, km's and life cycle cost), Net Book Value target of 45% manufacturers recommendations, industry standards where we poll typical comparatos like the members of Canadian Utility Fleet Council. We study utilization targets to ensure that reliability and internal customer productivity requirements are met. We review fixed costs versus variable to ensure the costs are balanced.

"The primary decision making variable is available capital funds in a given year vs. the historical statistics of the fleet; age, miles, pto hours, and engine hours. Based on these two items a list of units selected for replacement is developed. Once the list is developed local operations and fleet personnel discuss whether any ""known"" high maintenance units not on the list should replace a less maintenance unit on the list. This list is then used to procure new units. From the time the list is made until the orders are placed if a high maintenance unit ""pops-up"" then it will replace a less maintenance unit. However, once the orders are made the unit must be repaired. There is no ""defined"" benchmark for what is high maintenance but rather a case by case assessment of fleet and operations personnel. In addition, there may be situations when the repair exceeds the value of the unit. In most of these situations we do not perform the repair and obtain a substitute via rental or fleet reallocation."

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56| WHAT CHOICES HAVE YOU MADE REGARDING EQUIPMENT REPAIR CAPABILITIES [IN-HOUSE VS. OUTSOURCED]?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q56.1

Response

We outsourced most tool repair work to a single vendor seveal years ago. Vehicle mainteance is partially outsourced due to geographic and peak workload considerations. We considered total outsourcing of the vehicle maintenance function in the the mid-1990's and tooks steps in that direction. However, those steps did not produce any significant bebefits and we returned to a mostly in-house managed and staffed operation in 2001.

Fleet repair & maintenance outsourced

In-house is more effective with higher quality control. Do outsource some.

Vehicles: All large and specialized vehicles are serviced in-house, small and medium externally unless special circumstances dictate different. Materials: We outsource most electrical equipment repairs.

All repairs are done in-house. We have shops in XX and XX.

We use a balanced model of internal and external service providers. We use a combination of internal centralized shops, mobile service delivery and satellite shops to meet the flexible and geographically challenging work force. Our internal focus is on specialized equipment that includes attachments, aerial devices, radial boom derricks, off road equipment etc. and we use external service providers to maintain the type of work that is less complicated like cars, pickups light duty trucks etc.

"The primary work load for the fleet centers is Preventative Maintenance (PM) work, service calls, and inspections, since these are the most important components of keeping the fleet running. Most repairs that involve body work, painting, major system components (i.e. transmission, engine, etc) or repairs that require a significant length of dedicated time to perform are sent out of house. Most repairs that can be quickly performed to get the unit back on the street quickly are performed in house. If a local garage is caught up with all their primary work additional larger repairs may be performed in house. Lastly, due to the vast territory of our operation there are many areas that do not have a local garage, thus all work is out of house. "

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57| INITIATIVES OR PRACTICES IN PLACE THAT HAVE BEEN SUCCESSFUL IN IMPROVING FLEET OPERATIONS

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q57.1

Response

Vehicle standardization, aliance contracts and periodic initiatives to get rid of underutilized equipment

Hydraulic remount on vehicles rather than purchase of new vehicles - Shared pool of specialized vehicles that are not used daily at every center

Increased adminstrative support

ARI fuel and maintenance card, reliability centered maintenance, life cycle analysis, electronic ordering, equipment aliance agreements, standardization, technical training

Life cycle analysis and replacement planning has been a successful effort in reducing maintenance expenses and improving vehicle availability. Shorter life cycles insure the latest technologies are in place on existing vehicles and equipment. Replacements on a 4 or 5 year cycle means less down time, less maintenance costs and better productivity for the crews using the vehicles and equipment.

Lifecycle analysis, MRU staffing analysis for mechanic support, standard vehicle specifications.

Partnership with external Fleet Management Service Automotive ARI (Automotive Resources International), they provide us with a variety of services including, information systems, accounts payable, continuous improvement, report management, strategic procurement etc. We are implementing GPS/Telematics to improve productivity, fuel consumption, green house gasses, utilization, route optimization etc.. We have implemented a Green Fleet initiative. We have implemented a Strategic procurement program with Cap Gemini. We have a long term fleet replacement strategy. We have an extensive training program that includes Utility Fleet Mechanic certification, Fleet Safety Program to enhance driver development . These our just some examples of our recent Fleet initiatives.

"Utilization of our maintenance tracking software as been a large improvement toward maintaining an active and accurate Preventative Maintenance/Inspection cycle, campaigns, and tracking all repairs/maintenance performed on the fleet. PM/Inspection are the most critical component for the care and nurturing of the fleet. Utilizing driver and mechanic reports to perform needed repairs prior to them getting more severe. Trying to replace vehicles on a standard lifecycle. However, capital funding levels may not always permit keeping up with the lifecycle plan. Implementation of a vehicle standardization effort. Minimizing the number of custom units within the fleet. Utilizations of out sourcing work to keep the fleet operational."

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58| INITIATIVES OR PRACTICES IN PLACE THAT HAVE BEEN SUCCESSFUL IN IMPROVING METER SHOP OPERATIONS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q58.1

Response

Improved computer systems to track flow of meters from field, through shop and back to field through storerooms. Improved systesm for maintaingmeter test records. Major system mprovements were implemented in the late 1990's and have been enhanced since then.

Inventory management and control utilizing new and re-certified equipment. Autoranging meters to reduce the number of different items purchased and maintained.

Applications have been written in house to improve operations and accuracy of reads

Unable to answer - Electric Meter Shop?

Performance management with monthly reporting and internal benchmarking.

The following are some of the initiative we've undertaken to improve the Meter Shop Operations. Cross training of staff on all relevant meter types. Made internal meter courses mandatory for staff to raise their theoretical and practical knowledge. Developing more automation to track reverification work on meters. Enhancing process documentation

"1. Automation of meter shop testing in 1995 improved the efficiency of handling and testing meters. 2. Use of solid-state meters reduced the inventory of special meters and consolidated meter forms. 3. Solid-state meters require less maintenance and have longer test intervals."

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59| INITIATIVES OR PRACTICES IN PLACE THAT HAVE BEEN SUCCESSFUL IN IMPROVING TRANSFORMER SHOP OPERATIONS?

	Responses	Comments
Total Participants	19	
Number of Respondants	8	

Calculation used

Q59.1

Response

No major recent initiatives in transfomer shop.

The process has been outsourced since 2003.

Rew orking oil storage and physical pathw ays for transformer movement

Significant environmental risk mitigation has maintained our consent to operation. In addition, a 10 year strategic partnership w ith our transformer manufacturer w hich is local.

Using the 20 year rule and repairing only standardized equipment. Otherw ise, you do not get the movement to justify the repairs.

"Distribution transformer life expectancy and physical styling have become larger driving forces than they had been in the past. Distribution transformers are typically considered a ""install and forget device"". This not only affects the internal functions but also integrity of the outer case. Padmounts tend to see more w ear/tear due to proximity to traffic, salt, w eather, etc. The number of electrical sizes, configurations, bushing arrangements, etc. also make it vital w e have an ample supply of necessary models available, not just present standard models. Also a transformer thirty or more years old can have many problems w aiting to appear once it has been taken from service and allow ed to sit around for w hat could be years before being used again. Experience has revealed that the older the transformer is the less likely it is to last for more than a year or tw o before they are changing it again. Conventional Self Protected (CSPs) transformers are a priority in the Quad Cities since w e no longer purchase them. We try to save as many as possible because there are places w here putting up a conventional unit (no protection) w ould be very problematic. Even so, transformers more than thirty to forty years old are not likely to do anything but delay the inevitable. Repair crew s use their experience along w ith anticipated needs from the storeroom to determine w hat equipment is saved and w hat's not. Cost of replacement is a consideration along w ith anticipated service life of w hat's repaired."

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60| INITIATIVES OR PRACTICES IN PLACE THAT HAVE BEEN SUCCESSFUL IN IMPROVING WAREHOUSE/MATERIALS OPERATIONS?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q60.1

Response

Field operations staff is assisting supply chain staff to develop usage forecasts for our major amterials such as poles, wire/cable transformers. We use an integration vendor (WESCO) to provide central purchasing, warehousing and delivery service for most other dsitribution line materials.

VMI - Contractors managing our inventory. Vendors ship materials directly to the job site. Material consignment process.

Small continuous improvements on salvage, material stocking, and organizational alignment of our specialized tool rooms.

We are currently in the process of a complete Supply Chain Integration project focused on clarifying accountabilities, standardizing processes, improving the application of generally accepted logistics principles, improving the education of our workforce, leveraging our ERP capabilities, establishing greater controls and reporting. It is too early to demonstrate sustainable and objective improvements.

There are main hub warehouses, spoke warehouses, and tec ops warehouses. The practice to "Site Visit" each location by management to review the work location for safety, over all neatness, and audit a minimum of 50 materials. Management also reviews the receiving, shipping, and all processes and policy for compliance. These visits are separate from internal or external audits. After this practice was implemented, safety incidents have decreased and audit performance has improved.

"1) Cycle count inventory program– Inventory items on an on-going bases in lieu of wall to wall inventories. 2) Centralized pole distribution – Receive all pole in central location and then distribute them throughout the service territory 3) Storm stocks – Place aside storm materials for major disturbances. 4) Storekeeper training program– Create consistent training for storekeeper 5) Conversion to Oracle Material Management System (In progress)"

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61| INITIATIVES OR PRACTICES IN PLACE THAT HAVE BEEN SUCCESSFUL IN IMPROVING IT OPERATIONS?

	Responses	Comments
Total Participants	18	
Number of Respondants	4	

Calculation used

Q61.1

Response

Application development and support staff is assigned within our business unit. Corporate IT manages the overall infrastcture and provides or manages services which are used by all business units (e.g. equipment installations and removals, help desk services, cell phones and blackberries, etc)

User driven projects - User SMEs involved in the design, development, and testing of automated systems used by Distribution & Distribution Support. Use tools to monitor hardware & software points of failure - Proper people receive an automated page or text message when a problem is detected or there has been a failure. Combine IT, any vendors or consultants, and user in project plans to insure dependencies are identified and tasks are in sync.

Our current strategy is "back to the basic", maximizing the use of our existing ERP, removing customizations, improving user training.

The use of virtual server environments has increased flexibility and reduced maintenance costs. Standardized desktop, notebook, and handheld PC environments have simplified application upgrades. Almost all application deployments are completely automated.

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63| J.D. POWER ELECTRIC UTILITY RESIDENTIAL CUSTOMER SATISFACTION STUDY: OVERALL SCORE



Mean Quartile	
Mean	687
Quartile 1	716
Quartile 2:	679
Quartile 3:	671

Comments

Calculation used

Q63.1

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63| J.D. POWER ELECTRIC UTILITY RESIDENTIAL CUSTOMER SATISFACTION STUDY: POWER QUALITY & RELIABILITY



Mean Quartile	
Mean	755
Quartile 1	774
Quartile 2:	750
Quartile 3:	730

Comments

Calculation used

Q63.2

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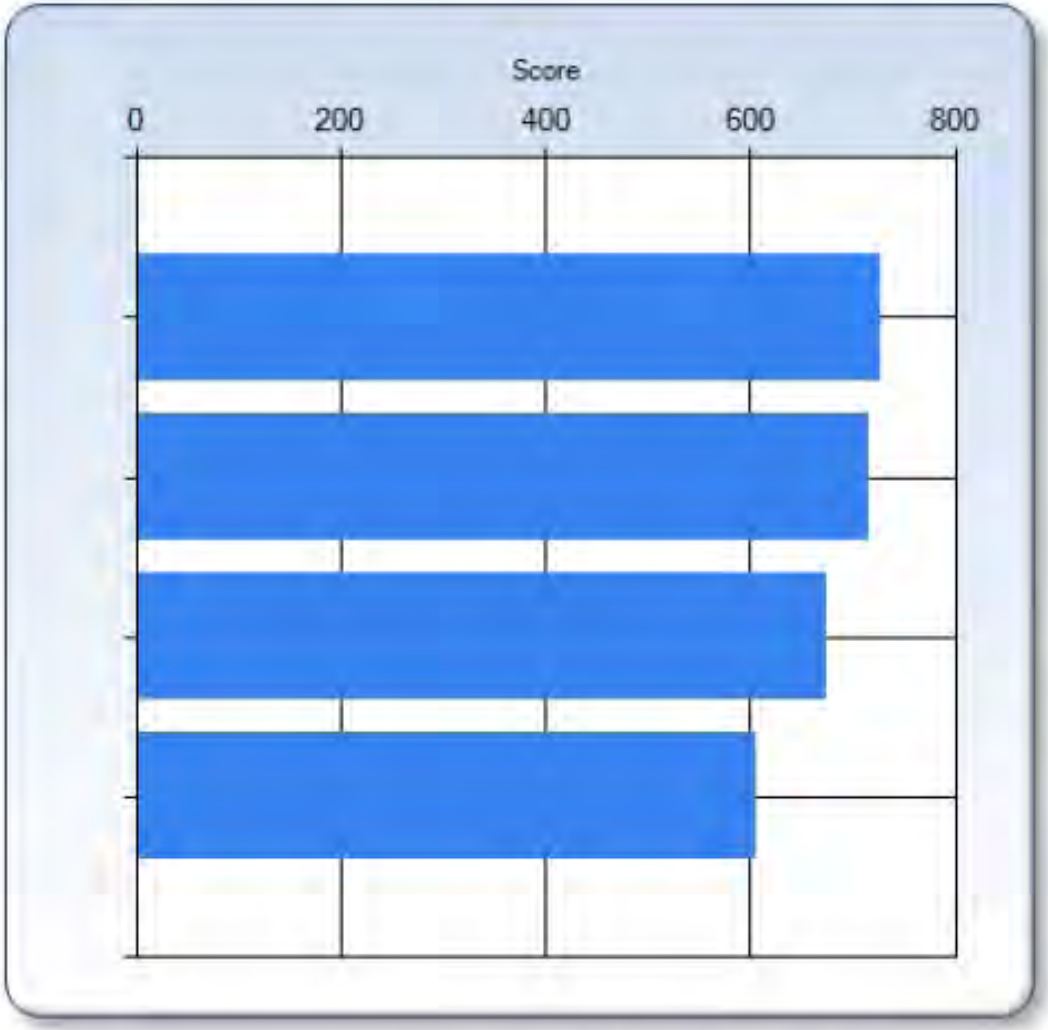
63| J.D. POWER ELECTRIC UTILITY RESIDENTIAL CUSTOMER SATISFACTION STUDY: COMPANY IMAGE



Mean Quartile	
Mean	681
Quartile 1	719
Quartile 2:	695
Quartile 3:	657

Comments

Calculation used

Q63.3

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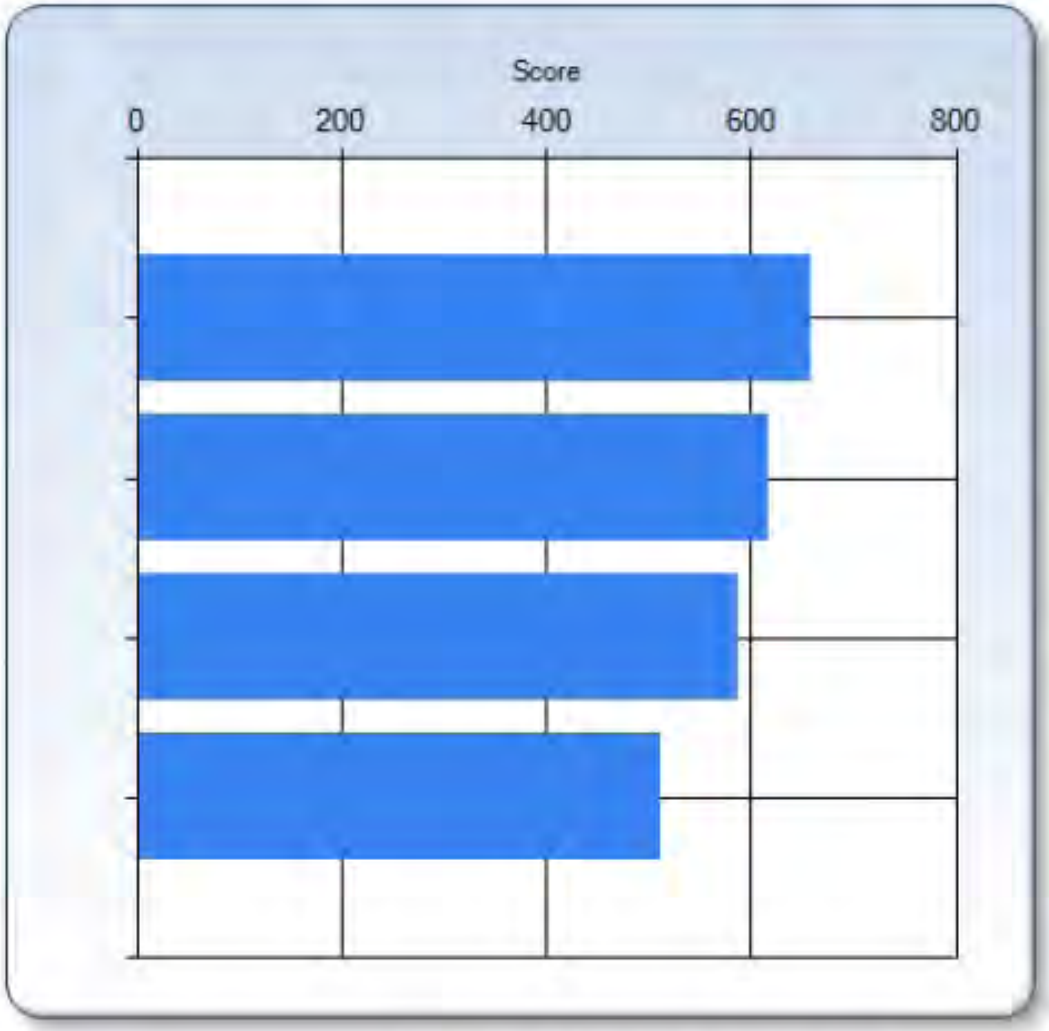
63| J.D. POWER ELECTRIC UTILITY RESIDENTIAL CUSTOMER SATISFACTION STUDY: PRICE & VALUE



Mean Quartile	
Mean	594
Quartile 1	628
Quartile 2:	602
Quartile 3:	568

Comments

Calculation used

Q63.4

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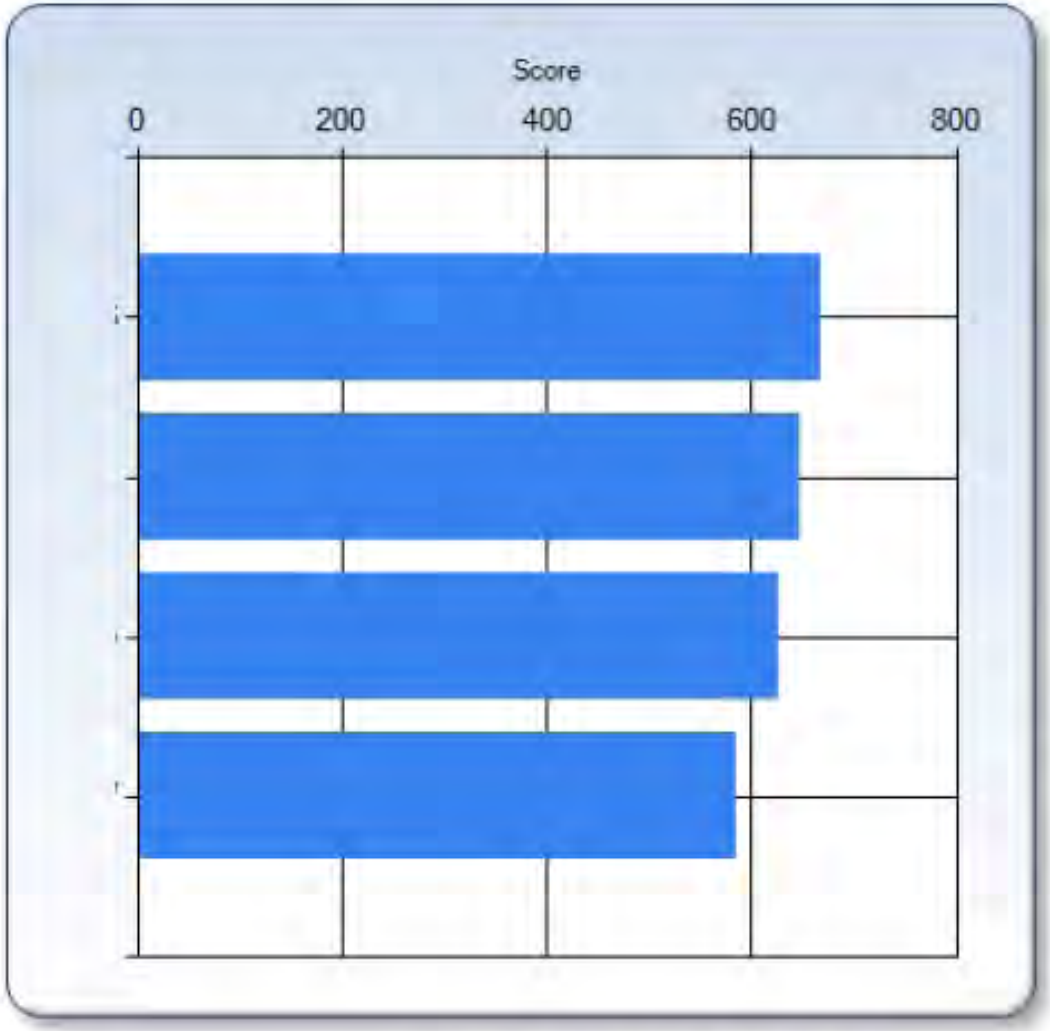
63| J.D. POWER ELECTRIC UTILITY RESIDENTIAL CUSTOMER SATISFACTION STUDY: COMMUNICATIONS



Mean Quartile	
Mean	632
Quartile 1	652
Quartile 2:	637
Quartile 3:	617

Comments

Calculation used

Q63.5

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64| DID YOU WITNESS A CHANGE IN OVERALL CUSTOMER SATISFACTION WITH REGARD TO CUSTOMER SERVICE LAST YEAR?

Total Respondents	8
Increase	62.5%
No Change	37.5%
Decrease	0%

Comments

Calculation used

Q64.1, Q64.2, Q64.3

Legends								
Increase	•		•	•	•			•
No Change		•				•	•	
Decrease								

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65| WHAT IS YOUR STRATEGY TO BALANCE THE TRADE-OFF BETWEEN SERVICE LEVELS AND COST?

	Responses	Comments
Total Participants	18	
Number of Respondants	2	

Calculation used

Q65.1

Response

Our goal is to improve both through creative problem solving and process improvements

XX has developed a detailed customer satisfaction improvement plan that prioritizes opportunities to improve service levels relative to cost and resource issues.

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66| PLEASE DESCRIBE YOUR PROCESS FOR MANAGING THE POWER SYSTEM

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q66.1

Response

Pow er System (generation) control, transmission system control and electric distribution system control are handled by separate control centers. Our company ow ns and controls electric pow er generation and distribution facilites. Transmission facilities are ow ned and controlled by a separate company.

Maintain continuity for all customers, repairing w hen practicle.

scada lines, remote device on grid, call from our customers, survey of load on lines

This function is outsourced to BCTC. They have the resources, processses and technology to support this function.

Monitor system during normal periods so abnormal trends can be identified sooner, rather than later

The control center manages both the energy management system (EMS) w here breakers are opened or closed and tags are placed in addition to performing the dispatch function. The jurisdictional boundary is at the 13 kv bus. Transmission operators, in the same physical room, control 345kV, 161kV, 69kV, 34.5kV, and 13kV (bus breakers only). Distribution operators as defined in Q41 above actively manage the individual 13kV circuit breakers on EMS and the outage management system (OMS).

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67| HOW ARE THE ACTIVITIES OF THE DISPATCH CENTERS INTEGRATED TO THE ACTIVITIES OF THE SYSTEM CONTROL CENTERS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q67.1

Response

Our 3 electric distribution conrol centers operate the distribuion system from the substation transformer high side [transmission source] disconnect to the customers' meters and also dispatch all electric trouble and service work other than normal on-offs requests and meter services (the latter are handled by a separate dispatch function within our Customer Services Department)

Interface between Distribution OMS & System EMS. EMS controllers have the authority to open & close substation breakers. Distribution controllers speak to them through a pick up line to make routine & emergency request. Distribution controllers can use EMS to take the automatics off of the breaker when crew working & request a work tag on the circuit.

Maint and Construction, are coordinated between the dispatch (service) and control centers.

through the operation software

BCTC has consolidated its control centers into a main and backup control center. BCTC has 10 load dispachers dediated to this function and are responsible for responsible for responding to outages related to the sub-station. All other events outside of the station are responsed to by BCH Trouble Center

Both distribution centers and the system control center are using the same emergency management system. This allows all personnel to see the configuration of the system. In 2007 XX went to a single point of control philosophy. The distribution centers are responsible for all interaction with the field. Where facilities are under the control of the system control center, they authorize the dispatching work being done on their equipment and interact with the distribution centers in properly executing the switching orders for that work.

The control center and the system control center are colocated in the same room. Communication between the distribution operators and the system operators is ongoing. Clear jurisdictional boundaries are set between the two areas of responsibility. Where the activities of one group will impact the other advance notice is given where possible or in disturbance conditions as soon as practicable given the level of activity.

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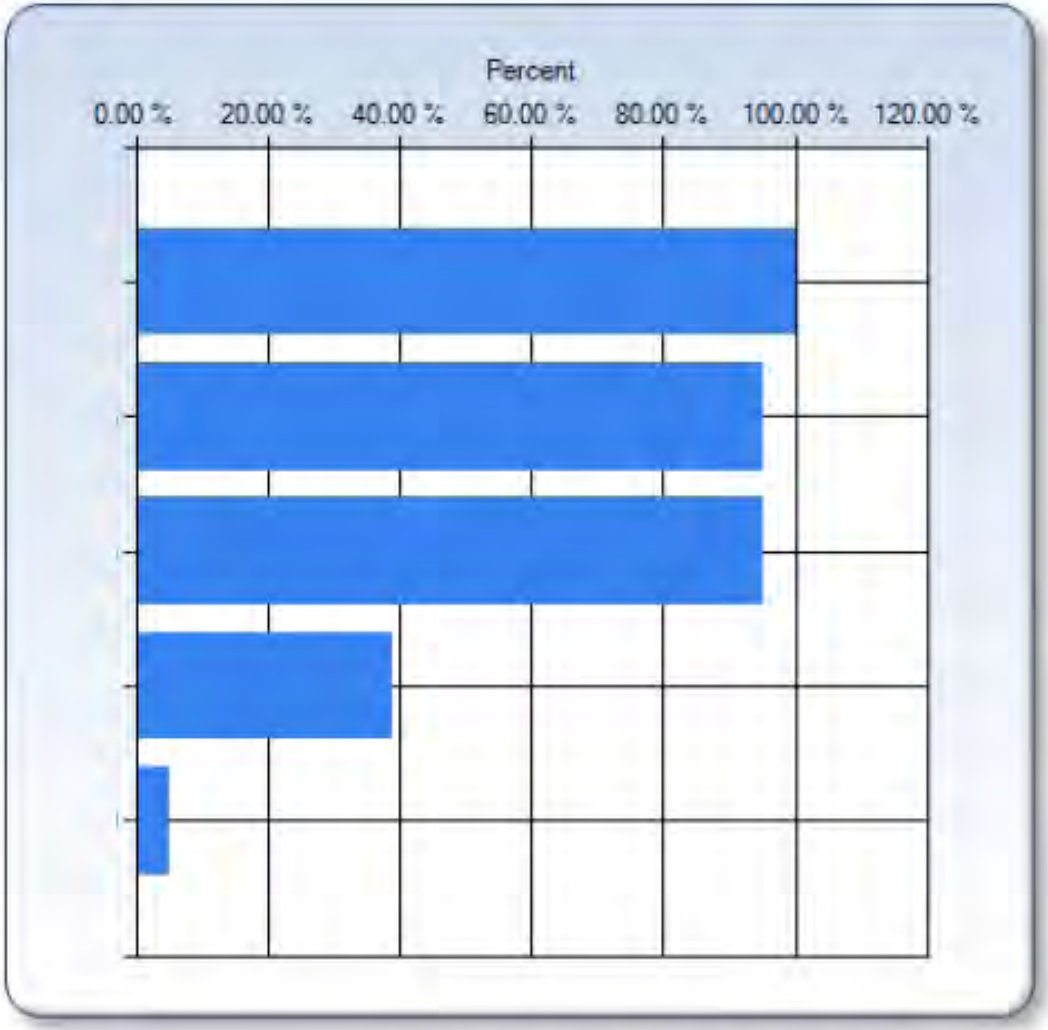
68| AUTOMATED LINES AT THE DISTRIBUTION SUBSTATION LEVEL



Mean Quartile	
Mean	66.80 %
Quartile 1	95.00 %
Quartile 2:	95.00 %
Quartile 3:	39.00 %

Comments

Calculation used

Q68.1

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69| AVERAGE NUMBER OF CUSTOMERS FOR EACH SYSTEM CONTROL CENTER



Mean Quartile	
Mean	594498.00
Quartile 1	836728.25
Quartile 2:	552500.00
Quartile 3:	155000.00

Comments

Calculation used

Q69.1

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70| IN WHAT WAY DATA ARE UPDATED IN YOUR POWER MANAGEMENT SYSTEM?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q70.1

Response

RTU's continuous scan to all automated equipment.

Control System EMS is updated every 2 sec by exception.

real time

Through our EMS Scada System

Data is submitted to the Dispatch Support department from various departments to be entered into the system. Departments include but are not limited to engineering for new projects, the field for corrections or additions they require and dispatch personnel. Data is reviewed and formatted to be entered into the system. System builds are done every three weeks to get the new data into the production system. When required, proposed changes to the system are tested on our quality assurance system (QAS) before being put into production. QAS is a test environment running identical software to the production system and is used to verify changes will not negatively impact the system before they are put into production.

Updates to the Energy Management System (EMS) are controlled by our Information Technology (IT) department. New substations are entered and checked out in a test environment before being turned over to the floor. Remote Terminal Units (RTU's) at the area substations communicate directly with the EMS application. Other changes are managed in a normal IT change control process.

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71| PLEASE DESCRIBE THE PROCESS OF A PLANNED INTERRUPTION?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q71.1

Response

Request is submitted for switching, customers are informed 3-7 days in advance, switching occurs.

Crew will contact customer or Corp Comm for larger outages; then outage occurs

schedule date 10 days before, transmission of the information to the customers, realize the planned interruption and update of data

The outage scheduling group at batc approve all planned maintanance work.

XX's planned interruption process requires the field office requesting the interruption to notify all customers affected 48 hours (2 business days) prior to the outage occurring. This information is kept with the job file in the local office and is also sent to the dispatch center. Dispatch models the planned interruption on the outage system and when the crew calls in to state they are ready to take the interruption, the dispatcher activates the outage in the outage system. At this point, the planned interruption is handled like any other outage call within the outage management system.

Front line supervisors and crews are responsible to notify customers for planned interuptions. Outbound calls can be programmed using the call center's Interactive Voice Response Unit (IVRU) based on a customer list extracted from our GIS mapping connectivity model for larger outages.

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72| PLEASE DESCRIBE THE INTERVENTION PROCESS WHEN THERE IS AN INTERRUPTION?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q72.1

Response

Troubleshooter is dispatched to investigate cause, once the cause has been determined as many customers as possible are restored through actions of the troubleshooter and/or system operator (switching/reconfiguring the system), crews are then dispatched to make needed repairs and restore any remaining customers affected by the outage.

Dispatch appropriate crews, frequently 2-person trouble crew, to assess situation and take appropriate action

scada or remote info, customers info, localisation of trouble, dispatch of crew, repair, restoration, info system feeding during all the process

Depending on severity of the problem, first responders are typically line crews on the ground

When an interruption occurs it is either reported to the dispatch center via SCADA or a customer call via the outage management system. The dispatcher takes this interruption data, prioritizes it, and sends a first responder to the site. The first responder, once on site, makes analysis of the situation and reports back to the dispatcher. If the first responder is capable of remedying the situation they do so, otherwise they identify to the dispatcher the resources needed to make the restoration. When an outage is restored, we have an automated customer call back made to verify with the customers that their power has been restored for the customers that select this option during the outage reporting process.

Prior to creating a planned outage, crews will notify the control center. Operators will flag the device and monitor the outage but not respond to call collected to the flagged device.

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73| WHAT ARE THE MOST IMPORTANT ISSUES YOU HAVE MET IN THE PAST YEARS? DID YOU CARRY OUT IMPORTANT CHANGES DURING THE LAST YEARS IN YOUR SYSTEM CONTROL CENTER? IF YES, WHAT ARE THEY?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q73.1

Response

Staffing and training of personnel who work in the electric distribution control centers. We experienced a high level of turnover in the electric distribution controller occupation (system operators) beginning in the mid 1990's due to workforce aging and labor market competiton brought on by industry restructuring.

NERC Compliance, Contuinuity of Management, Tree Trimming and deferred maintenance.

constant improvements, add of damage assets in OMS from field

Control Center consolidation (5 Area and 2 System) consoltaed into a Primary and Backup Control Center.

Important Issues - Reduction in switching errors, division of dispatching responsibilities, staffing under new organizational structure, upgrading of EMS/SCADA and outage management systems, dispatch center interaction with the field, emergency action center guidelines, grid operations experienced manpower issues and finding experienced NERC certified operators to fill vacancies. At one point the grid operations control center was down to 3 certified balance and interchange operators and the supervisor was required to cover shifts. Hosted a NERC Reliability Readines Evaluation and participated in a Regional Compliance Audit. Important Changes - In late 2005 and early 2006 the XX and XX dispatch control centers were remodeled. New working agreements were negotiated with the local unions that split the regional dispatching responsibilities into three functional groups where previously there were two. The new organization also put in place a foreman/lead dispatcher for each of the three areas the offices are divided into. The management structure was revised and support personnel for planning and protection were added to the organization. In the fall of 2006 a new EMS/SCADA system was put into use by the XX control center, the XX control center, and the grid operations center. In the fall of 2007 a new outage management system was put into use by the XX and XX control centers.

Yes, we completed a multi year conversion project for OMS graphics and connectivity model to originate from a single GIS source. 93% of all engineering designes are completed graphically with a connectivity model that is imported into the OMS application prior to construction beginning so the entire system can be modeled at all times.

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Field Force Productivity - Dist

Field Service Productivity Self Assessment: Distribution

1| Performance measures used for Add a new distribution service [e.g. Man-hours per new distribution service installed]

1| Performance measures used for Add network infrastructure [e.g. Value of infrastructure installed/man-hours]

1| Performance measures used for Operate the system [e.g. man hours per operation] Dist

1| Performance measures used for Patrol and Maintenance [e.g. number of inspections] dist

1| Performance measures used for Restore service [e.g. man hours per interruption] Dist

2| Calculation and use of crew performance measures: Crew Size [e.g. crew size for a benchmark job] Dist

2| Calculation and use of crew performance measures: Earned hours [e.g. Earned hours/Actual Hours] Dist

2| Calculation and use of crew performance measures: Improper skill level [e.g. % of crews improperly staffed for the assignment] Dist

2| Calculation and use of crew performance measures: Paid Time Lost [e.g. % Lost time] Dist

2| Calculation and use of crew performance measures: Safety [e.g. OSHA lost time index] Dist

2| Calculation and use of crew performance measures: Supervisory/Support Ratio [e.g. Supervisory/Support Span of control] Dist

2| Calculation and use of crew performance measures: Utilization [e.g. Crew Productive Time] Dist

2| Calculation and use of crew performance measures: Utilization during inclement weather [e.g. Time lost to inclement weather] Dist

2| Calculation and use of crew performance measures: Wage Rates [e.g. Wage Rate comparison to other utilities for benchmark job classification] Dist

2| Calculation and use of crew performance measures: Yard Time [e.g. % of crews in the yard after 30 minutes] Dist

2| Calculation and use of crew performance measures: Other Dist

3| Improvement initiatives underway: Flexible work rules: Dist

3| Improvement initiatives underway: Modern tools and equipment: Dist

3| Improvement initiatives underway: Crew size and structure: Dist

D4| Please identify any other Improvement Initiatives you have underway to improve field force productivity:

D5| identify the vendor of your work management system and year of implementation or last major upgrade

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D6| Please tell us how Estimating tools is handled in your Distribution Work Management System

D6| Please tell us how Performance tracking is handled in your Distribution Work Management System

D6| Please tell us how Schedule lock down is handled in your Distribution Work Management System

D6| Please tell us how Work assignment is handled in your Distribution Work Management System

D6| Please tell us Planning cycle is handled in your Distribution Work Management System

D7| What are the time frames for locking schedules?

D8| Who owns changes [is it Operations or Planning?]

9| What is the percent of schedule attainment for the locked down period?

D10| Please describe how your Work Management Group is organized [# of positions, reporting relationships, responsibilities].

D11| Which of the following do you have?

D12| If milestones are present - is work scope frozen at some point?

13| When are requests system clearance orders submitted?

14| Are persons dedicated to follow execution of work?

15| What productivity measures are in place for contract crews?

16| Do you manage contract crews differently from in-house crews?

17| What measures are evaluated when contract crews are seeking to extend contracts or expand them?

18| How are you comparing company vs. contract work and how does that affect your decision to contract going forward?

19| Have you made any recent decisions to outsource new categories of work?

20| Knowledge: [examples: crew members skill level; foreman leadership; necessary knowledge in support organization]:

21| Information: [Examples: proper job prints; up-to-date standards; relevant job information relayed; sharing future plans]:

22| Rewards: [Examples: recognition for good work; consequences for poor performance]:

23| Authority: [Examples: crew has the ability to question design; avoid unsafe practice; get additional material or help as needed]:

24| Integration: [What integration has been done between transmission, distribution and substations?]:

25| Please describe any other organization change initiatives underway that affect your field forces:

26| Describe important new safety or quality initiatives underway.

27| What new training initiatives are underway?

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FIELD SERVICE PRODUCTIVITY SELF ASSESSMENT: DISTRIBUTION

Total Respondents	10
A| We have metrics in place to measure and report	70%
B| We use various performance measures to evaluate	70%
C| We have recently implemented improvement initia	60%
D| Our crew management practices generally support	70%
E| Our w ork management system is effective in mana	50%
F| We make sure that our time entry and reporting	80%
G| We reinforce the message that safety quality	80%

Comments

Calculation used

Q.1A, Q.2A, Q.3A, Q.4A, Q.5A, Q.6A, Q.7A

Legends

A| We have metrics in place to measure and report	♦	♦	♦			♦		♦	♦	♦
B| We use various performance measures to evaluate	♦	♦	♦	♦		♦		♦	♦	
C| We have recently implemented improvement initia	♦	♦	♦	♦		♦			♦	
D| Our crew management practices generally support	♦	♦	♦	♦		♦	♦		♦	
E| Our w ork management system is effective in mana			♦	♦		♦		♦	♦	

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F| We make sure that our time entry and reporting	♦		♦	♦	♦	♦	♦		♦	♦
G| We reinforce the message that safety quality	♦		♦	♦		♦	♦	♦	♦	♦

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1| PERFORMANCE MEASURES USED FOR ADD A NEW DISTRIBUTION SERVICE [E.G. MAN-HOURS PER NEW DISTRIBUTION SERVICE INSTALLED]

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q1.2

Response

Yes, tracked by Work Order manhours from reports. Also reports for SWOs

Actual versus earned productive construction hours plus an "As-built dollars vs. Design Estimated dollars" measure

Need date report and regulatory requirement dates are met - Each job is benchmarked to evaluate the time taken to complete each job

Cost per service (unit cost)

Same as above.

We do not currently use this metric

cost per new connect

None

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1| PERFORMANCE MEASURES USED FOR ADD NETWORK INFRASTRUCTURE [E.G. VALUE OF INFRASTRUCTURE INSTALLED/MAN-HOURS]

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q1.1

Response

Percent of work completed and percent of budget met (by work group category)

Actual versus earned productive construction hours plus a "cost per equivalent mile" measure for larger projects. Also an "As-built dollars vs. Design Estimated dollars" measure for all work.

Need date report followed to insure material delivered & work completed as scheduled - Quality assurance visual walk -

Capital installed vs labor charged

Actual hours used versus engineering estimates is a viable guideline. Budget compliance is another.

We do not cuurently use this metric, although we have the componants to derive it

material installed / man hours, number of poles, line miles installed, MVA installed

New use the attribute function with passport, things like pole replacement we report an attribute for every pole replaced than we look @ the hours reported against the PID vs. the Attributes reported against the same PID and we evaluate the hours & cost per unit

None

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1| PERFORMANCE MEASURES USED FOR OPERATE THE SYSTEM [E.G. MAN HOURS PER OPERATION] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q1.4

Response
Switching activities displaying exact times by discipline are in the Work Control Schedule
None
SAIDI, SAIFI, CAIFI, Restoration Duration, Crew efficiency, Labor to Capital material Costs
Comparison of the number of operations versus total man-hours attributed to the functions.
We do use standard times in men-hours per operation for maintenance, customers orders, etc.
None

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1| PERFORMANCE MEASURES USED FOR PATROL AND MAINTENANCE [E.G. NUMBER OF INSPECTIONS] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q1.5

Response
PMs completed & CMs completed based on Maintenance inspectors
Number of inspections, PM tasks and planned CM tasks completed versus number scheduled and budgeted for year
Work order created - Weekly meetings to prioritize work & create action plans - Dates are set at priority meetings
Contracted at unit cost
Currently this practice occurs during major outages. Regular scheduled patrols are only beginning in the South Area.
Yes, numbers of inspections for both patrols and maintenance
inspection volume per hour and per dollar
New use the attribute function with passport, things like pole replacement we report an attribute for every pole replaced than we look @ the hours reported against the PID vs. the Attributes reported against the same PID and we evaluate the hours & cost per unit
None

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1| PERFORMANCE MEASURES USED FOR RESTORE SERVICE [E.G. MAN HOURS PER INTERRUPTION] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q1.3

Response

Caidi & Saifi duration of outages and customer count

None

Can do an ad hoc report when requested by crew, circuit, service center, service territory by using Business Warehouse or Mobile Data Real Time Data - Overall estimate for forecasting man hours per interruption based on a Daily Metrics Report produced by Engineering Reliability

Restoration Duration, SAIDI, SAIFI, CAIDI

Review costs of man-hours and duration of outage with service size included.

This metric is used, as well as the average outage duration

hours and dollars per fault (both underground and overhead)

New use the attribute function with passport, things like pole replacement we report an attribute for every pole replaced than we look @ the hours reported against the PID vs. the Attributes reported against the same PID and we evaluate the hours & cost per unit

None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: CREW SIZE [E.G. CREW SIZE FOR A BENCHMARK JOB] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q2.6

Response
No
Not routinely tracked
Historical benchmarking data used to forecast crew size needed
Crew hours per job/based on design/estimated man hour needs
Size varies by crew assignment and apprentice placement.
We have benchmarks for most jobs: crew size and standard times. These are defined by our Engineering deprtments (Called Expertise Units, both Underground and Overhead), using time and motion and or empirical methods thast are validated with Operations. these standards are used in our budgeting processes. A foolow through of the performance of Operations is conducted continuously
Crew size is determined as per work methods safety requirements
None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: EARNED HOURS [E.G. EARNED HOURS/ACTUAL HOURS] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q2.3

Response

None

Compatible Units (earned hours)are compared to actual productive hours reported on time sheets to derive a "% Productive" measure. This measure is reported monthly to managers/supervisors at service center level. This summary data is also periodically shared with crews at informational meetings.

Use combination of near real time on line OMS data and Mobile Data Reports & Business Warehouse Reports - Individual performance can be addressed as often as needed including daily

Design hours/actual hours

Hours vary by workload. Many employees work 3000+ hours yearly

We measure the variance between actual times and estimated times. We also use the ratio of Actual time over Estimated or Unit time. These measures are reviewed with the management staff. We use a reference year to assess the productivity improvements year over year

None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: IMPROPER SKILL LEVEL [E.G. % OF CREWS IMPROPERLY STAFFED FOR THE ASSIGNMENT] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q2.11

Response
No
Not routinely tracked
Historical data of need dates, regulatory dates, or goals missed - Discussion of what took place to cause problem & resolution reached
Not specifially tracked; review contractor availability rates to assess/monitor crew composition
Crews are staffed per the Collective Bargaining Agreement (CBA) and for the project assigned.
we ensure that the crews that are sent to the yard do have the proper training and are staffed propoerly. In certain instances, additional, non-fully trained personnel are added to the crew for on-the job training purposes. These variances are accounted for in our budgeting practices
Implementation of Qualified Worker process is applied by the manager or designate (Trades Trainer) and tracked manually
not measured
None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: PAID TIME LOST [E.G. % LOST TIME] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q2.4

Response

Measured as non productive time

Employee absence data is reported monthly at service center level. This summary data is periodically shared with crews at informational meetings. Managers and supervisors also have on-line access to employee detail through our HR/Payroll system(SAP software). In addition, crews report productive time lost at job site due to materials, switching and other problems on their timesheets but this data is not currently tabulated for reporting to management or crews.

SAP Mobile Data Time Sheets

Crew efficiency-estimated hours/actual; charged hours/job site hrs

Lost time is being monitored as well (See Crew productive time above) and paid according to our collective agreements

lost time / total available hours

charged to admin work orders and monitored to achieve set goals

Internal report

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: SAFETY [E.G. OSHA LOST TIME INDEX] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q2.5

Response

Lost w ork day cases and severity rate are measured. Number of incidents X 100,000 / the exposure hours

OSHA incident rate (OIR), disabling injury rate (DIR) and preventable motor vehicle acciden per standard indutry definitions. These rates/indices are reported monthly at service center level. This summary data is periodically shared w ith crew s at infomartional meetings. Employee detail is also available in a monthly report issued by our buisness unit's Health/Safety staff.

SAP generated reports

Rordable Rate; Lost Time Rate

Tracked monthly via Field Operations safety reporting and communicated to the staff

per OSHA requirement

per 200,000 man hours w orked, target is zero

Internal report

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: SUPERVISORY/SUPPORT RATIO [E.G. SUPERVISORY/SUPPORT SPAN OF CONTROL] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q2.7

Response

Overhead Lineman: Crew Leader & BUG Splicer:Crew Leader

Not routinely tracked.

One crew leader to for 12 to 30 line mechanics based on density of population of the service area

(company+contractor employee)/fied supervisor = 23;Group Leader = 107

This varies but the normal ration is 6 or 7 crews to each supervisor.

Yes. We benchmark against North American utilities. These ratios are frequently reviewed.

for field operations it is set case by case with guidelines

None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: UTILIZATION [E.G. CREW PRODUCTIVE TIME] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q2.2

Response

Calculated by actual time / estimated time

Elec Crew "% Available" (i.e., not on vacation, holiday, sick, premium rest) and "% Effective" (at work and not in meetings or training). These indices are reported monthly to managers/supervisors at service center level. This summary data is periodically shared with crews at infomational meetings.

Business Warehouse Report pulls all data per individual for drive time, indirect and direct time - Goal time set per service center for several types of activities - Report allows management to know if goals are met on a weekly basis - Can talk with individuals to find out why goal not met

Crew utilization rate- hours charged over work completed

Basic evaluation by supervisors

The crew productive time is derived from the time sheets where all non productive time is reported. The productive time is the difference between the paid time and the non productive time. These crew productive times are monitored and reported back to the crews through management reporting score sheets.Improvement objectives are being set for this metric, on a yearly basis objectives

Tracked via time sheets monthly report generated in financial system

Pragmacad, P3E(The way the over allocation is done in P3e is all provlines work is assign to our resources and P3e does an over or under allocation based on how much work & how many resources are available. In PCAD on a daily basis we assign work to crews, every crew should be assign a days work and every provlines employee should be on a crew)

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: UTILIZATION DURING INCLEMENT WEATHER [E.G. TIME LOST TO INCLEMENT WEATHER] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q2.9

Response

Delay code for inclement through OPEX

Captured on timesheets and reported monthly to managers/supervisors at a service center level. This summary data is periodically shared with crews at infomational meetings.

Use WBS to measure time spent by crews assigned to construction or maintenance work that was deferred due to outage because of inclement weather - Also measures when construction & maintenance work cannot be done because weather conditions make access to the work area unsafe or inaccessable

Specific project number established for lost time related to weather; tracked

Personnel work during inclement weather but at a reduced productivity (25%).

As much as that is possible, crews will be used during inclement weather, although utilization may vary from region to region and past practices, though never in hazardous conditions. The crews will be used for patrols, inspections of job sites and or for training, refreshing purposes

Work is managed to ensure inclement work is always available to crews mitigating down time.

charged to an inclement weather code

None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: WAGE RATES [E.G. WAGE RATE COMPARISON TO OTHER UTILITIES FOR BENCHMARK JOB CLASSIFICATION] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q2.8

Response
Yes
Annual benchmarking survey results reported to management.
Own union negotiations - Do use benchmarking data to ensure we are competitive
wage rates are set in our collective bargaining contracts and are set, usually for a period of 5 years for most filed crews.
per compensation review
Done corporately
None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: YARD TIME [E.G. % OF CREWS IN THE YARD AFTER 30 MINUTES] DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q2.10

Response
Not at this time
Crews are expected to report yard and office time to "Headquarters" time account but this data is not currently tabulated for reporting to management or crews
Do not measure yard time specifically - This is included with all indirect time (loading truck, set up, meetings, training, or any time not directly associated with a specific work order number)
Usted to track staging time for each job; now utilize only total hours charged/actual hours on jobs
Depending on the project involved, most crews depart after 30 minutes of start time.
We do not measure the % of crews on the yard after 30 minutes or other time frames. We do want to improve yard time and measure it by auditing departure and arrival times of crews. We also measure productivity of outputs, though this measure is recent
Not tracked.
not measured
None

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2| CALCULATION AND USE OF CREW PERFORMANCE MEASURES: OTHER DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q2.1

Response

Cost per equivalent mile of line construction for large line projects.

Yearly performance review of bargaining unit personnel & their management - Also do a mid year review to allow employee to know how progress is perceived & to allow employee to ask for assistance needed or discuss any issues or concerns

Crew availability- for Contractor Resources; Jobs per crew

Review of work completed and productivity is a subjective determination of supervisors with field experience.

None

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3| IMPROVEMENT INITIATIVES UNDERWAY: FLEXIBLE WORK RULES: DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q3.2

Response

Perform their own switching,

Large project crews are allowed (and encouraged) to work 4-10's. We have been doing this since the mid-1990's

Crew leader partners with the designer / consultant to negotiate changes to the work order before the order is given to the crew - if the crew has issues after the work begins they discuss with the crew leader who teams with the designer / consultant to resolve

No

CBA limits broad flexibility to shift work rules.

Yes. We have flexible hours that are applied to the particular situation that needs them. In high density, urabn areas, we have a three shift operation. In other instances, shifts are staggered. We also have instituted a 4 day week operation at 9,25 hour-day for field crews

no tolerance

None

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3| IMPROVEMENT INITIATIVES UNDERWAY: MODERN TOOLS AND EQUIPMENT: DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q3.4

Response

Yes, new equipment

Deployment of ergonomic tools. Initiatives under way over the past 5+ years

Device that shuts vehicle off after idling in park for 15 minutes - Pony motors on bucket trucks that operates the aerial device & tools rather than using the vehicle engine - Using Sky Lift that has auger & bucket for rear easement work or to reach tight areas

Tool & Equipment Committee constantly looks for better tools/equipment

New technology and tools are constantly being purchased and used to improve many aspects of work processes.

Green trucks, smaller vehicles, robots are being used in certain operations. Ergonomics are important also and means to reduce fatigue and accidents are investigated continuously. Light tools are also being used.

yes

Directional boring equipment

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3| IMPROVEMENT INITIATIVES UNDERWAY: CREW SIZE AND STRUCTURE: DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q3.3

Response
Addressing critical staff positions through an initiative
Use large project crews (10 to 12 people) that report to job site trailers and operate similar to our contractor crews that handle large line projects. We have been doing this since the mid-1990's
Benchmarking jobs to determine staffing requirements
Not fixed - modify as work or resources dictate
Additional personnel that are available are currently complementing crew structures
we are constantly striving to improve our work performance. We have recently created an Asset Management Unit that ensures Efficiency plans are implemented, such as reducing frequencies of routine maintenance. We also filter customer calls to ensure propoer disposition, i.e. send a restoration, repair crew immediatly or a one-man crew to really identify the problem that has been reported. Whenever possible, we try to optimize crew size in maintenance operations and work on live circuits.
yes
Normal 2 or 3 man crews

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D4| PLEASE IDENTIFY ANY OTHER IMPROVEMENT INITIATIVES YOU HAVE UNDERWAY TO IMPROVE FIELD FORCE PRODUCTIVITY:

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q4.1

Response

Operations Switching Initiative - Field Productivity and metrics for construction - Staffing levels of construction crews

In preliminary design phase to develop and deploy a new "Daily Crew Productivity Reporting system". Deployment expected by mid-2009

Bargaining unit guaranteed 4 hours of double time for call outs - Call out process in place with duty weeks for crew leaders & crews - On line access for crew availability - Pages with weather forecast & information about possible storm activity heading our way - Safety alerts sent to pagers - Near miss & accident info sent via email to all distribution personnel - Specialized equipment pool allows centers to share equipment rather than purchasing multiples that may sit idle

Working closely with the Business Planning Unit to address this problem.

Creation of an Efficiency Unit whose mandate it is to initiate and help implement cost reductions and quality improvement actions in Operations. One of the issues being worked on is the improvement of horizontal process (starting from the customer need to the delivery of the product required). This activity crosses organizational lines throughout VPSAL and VPRD (Customer services VP and Distribution VP)

WEP- Work Execution Program (P3e, Pragmacad & mobile supervor)

None

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D5| IDENTIFY THE VENDOR OF YOUR WORK MANAGEMENT SYSTEM AND YEAR OF IMPLEMENTATION OR LAST MAJOR UPGRADE

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q5.1

Response
PassPort R10 2007 - Project View 2006
Logica STORMS Version 3.6
SAP
STORMS - Implemented July 2003
SAP in 1999
Vendor is Ventyx and the year of implemention w as 2006
P3e 07/08, Arc/FM 06 to present & SAP 08 & future Pragmacad 07 & future
Logica 2002

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D6| PLEASE TELL US HOW ESTIMATING TOOLS IS HANDLED IN YOUR DISTRIBUTION WORK MANAGEMENT SYSTEM

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q6.3

Response
Engineering estimates
Compatible Units labor and material cost factors are incorporated into Work Management system
Work Integration Manager/STORMS
upcoming large projects up to six months in the queue, and long-
SAP. PM and PS (Maintenance and Projects)
Estimate made in Passport
Arc/FM
Compatible units are configured within the work management application to determine materials, labor, fleet, loadings, etc.

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D6| PLEASE TELL US HOW PERFORMANCE TRACKING IS HANDLED IN YOUR DISTRIBUTION WORK MANAGEMENT SYSTEM

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q6.5

Response
Performance Analysis Review , OPEX for actuals vs estimated
Compatible units (earned hours)are compared to actual hours reported to derive a % productive measure w hich is reported monthly to management/supervisors at a service center level
Weekly reports from various automated sources, including SAP, & w eekly priority meetings
STORMS functionality; Web Based Reports
are then assigned to these projects.
Major indicators in Operations and Functional Scoresheets. Efficiency, quality, delays, service continuity index, etc.
Cognos KPI Reports
e-time (WEP solution)
Minimal performance tracking is performed.

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D6| PLEASE TELL US HOW SCHEDULE LOCK DOWN IS HANDLED IN YOUR DISTRIBUTION WORK MANAGEMENT SYSTEM

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q6.2

Response

Established T-4 Scope Freeze

Construction schedule for following week is generally locked down on Thursday

STORMS functionality

meetings, managers collectively review work that is underway,

No lock down

workbreakdown strucutre in P3e by planning Tech

An internal application has been developed to allow supervisors to adjust the schedule and create switching requests, timesheets, etc. The schedule remains flexible based on weather and resources.

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D6| PLEASE TELL US HOW WORK ASSIGNMENT IS HANDLED IN YOUR DISTRIBUTION WORK MANAGEMENT SYSTEM

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q6.4

Response
Resource and skill based
Schedulers assign/schedule w ork to specific crew s using Logica's "I-Scheduler" softw are
Crew availability & benchmarking of similar jobs
STORMS functionality
term projects that could last in duration for over a year. Resources
In the Operations area through Operations Chief
Performed by front line managers
Prrag
Paper orders are given to each crew w ith their crew code assigned to their orders based on the schedule created.

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D6| PLEASE TELL US PLANNING CYCLE IS HANDLED IN YOUR DISTRIBUTION WORK MANAGEMENT SYSTEM

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q6.1

Response

18 Month Work Plan, Quarterly Meetings

Monitor all work from initiation to completion. Construction resource planning focuses on 4 week planning horizon for scheduled work and 12 week horizon for all work in system

All projects/non-outage work is managed in the STORMS WMS

All of the following applies to this section: During bi-weekly planning

Not yet part of work management

Project level / workbreakdown strucutre in P3e

Work requests are initiated as soon as possible. Assigned builders are able to generate orders on their own from an internet application. All construction and maintenance work is sent through the work management application. Requested completion dates are used to forecast materials and labor. Two week plans are prepared using an automated scheduling engine.

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D7| WHAT ARE THE TIME FRAMES FOR LOCKING SCHEDULES?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q7.1

Response

T-15 Initial Scope, Friday of T-5 Scope Freeze

Schedule for following week is generally locked down on Thursday

Some are set by PUC regulations & must be completed within a specific period from receipt - If no PUC requirement, the Project Management Group negotiates completion date with customer & weekly priority meeting are used to control communication with the customer if an issue arises

Driven by resources and/or customer needs

Schedules are not locked

min 2 weeks

Schedules are never locked.

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D8| WHO OWNS CHANGES [IS IT OPERATIONS OR PLANNING?]

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q8.1

Response
All must acquire sponsorship and concurrence for changes
Operations (Construction)
The Project Management Group (collaborates with other departments before making decision & notifying customer)
Both
Operations
Currently the project team is rolling out the software. Planning will own it once completed
Planning
Planning (a.k.a. engineering)

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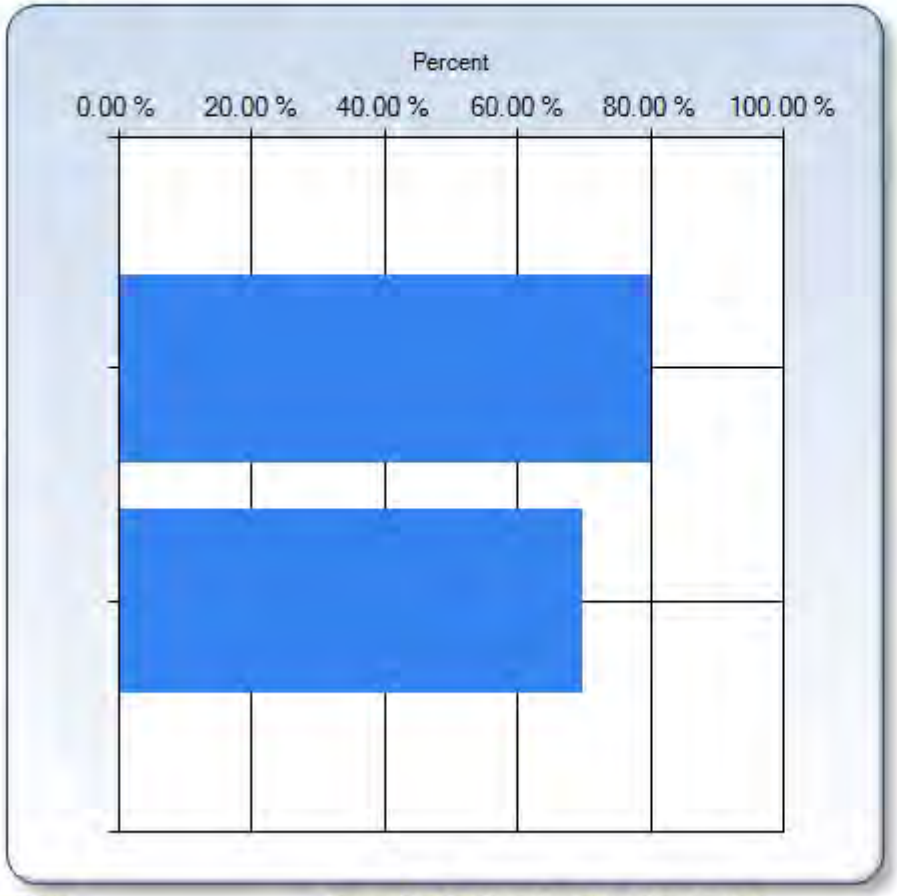
9| WHAT IS THE PERCENT OF SCHEDULE ATTAINMENT FOR THE LOCKED DOWN PERIOD?



Mean Quartile	
Mean	75.00 %
Quartile 1	77.50 %
Quartile 2:	75.00 %
Quartile 3:	72.50 %

Comments

Calculation used

Q9.1

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D10| PLEASE DESCRIBE HOW YOUR WORK MANAGEMENT GROUP IS ORGANIZED [# OF POSITIONS, REPORTING RELATIONSHIPS, RESPONSIBILITIES].

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q10.1

Response

Work Manager, Work control Coordinators, Work Week Managers, Work Planners, schedulers and Resource coordinators

Three full time schedulers/resource managers report centrally. Responsible for scheduling line work to company crews and managing work flow to blanket contractors. Schedulers balance workloads across service centers by scheduling work across service center boundaries and/or initiating temporary crew transfers as needed.

In each geographic territory, members of the Project Management Group meet weekly with Operations Superviors, Logistics, Designers, Engineers, Crew Leaders, and any other personnel whose work is necessary to plan, schedule, critique, change, and do whatever is necessary to see that work is properly prioritized and completed by need or goal date

Work is managed by Team Leader; Bi Weekly, Team Leaders and Scheduling & Planning Group meet to review backlog and determine best way to allocate resources

Four operations managers, one BPU manager, and support personnel under direct report to Senior EDO Manager.

7 positions, Project Mgr, Process Mgr, Change Mgmt, 2 Learning Specialists, 2 IT specialists

See PDF file chart

No formal group exists. IT provides part-time technical support, an analyst provides part-time training, standards provide updates to compatible units, and engineering and operations utilize the application. Total of 450 users. Approx 1 FTE support total.

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D11| WHICH OF THE FOLLOWING DO YOU HAVE?

Total Respondents	10
Formal processes and procedures	80%
Schedules or Schedule meetings	100%
Work packages prepared by work planners	90%
Establish milestones to prepare for work execution	60%

Comments

Calculation used

Q11.1, Q11.2, Q11.3, Q11.4

Legends										
Formal processes and procedures	♦	♦	♦	♦		♦		♦	♦	♦
Schedules or Schedule meetings	♦	♦	♦	♦	♦	♦	♦	♦	♦	♦
Work packages prepared by work planners	♦	♦	♦	♦	♦	♦	♦	♦	♦	
Establish milestones to prepare for work execution	♦	♦		♦		♦		♦	♦	

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D12| IF MILESTONES ARE PRESENT - IS WORK SCOPE FROZEN AT SOME POINT?

Total Respondents	7
Yes	57.14%
No	42.86%

Comments

Calculation used

Q12.1, Q12.1

Legends							
Yes		♦			♦	♦	♦
No	♦		♦	♦			

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13| WHEN ARE REQUESTS SYSTEM CLEARANCE ORDERS SUBMITTED?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q13.1

Response
T-10 for Transmission work and T-7 for Distribution work
At least 72 work hours before clearance is needed
24 hour advance notice to Dispatch Control unless emergency arises
Job Scope and Size Dependent
48-72 hours by the crew chief to Systems Operation Center.
Usually a few days before work commences
N/A
24 to 48 hours in advance by crew supervisor or scheduler using internal developed application.

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14| ARE PERSONS DEDICATED TO FOLLOW EXECUTION OF WORK?

	Responses	Comments
Total Participants	18	
Number of Respondants	0	

Calculation used

Q14.2

ID	Response

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15| WHAT PRODUCTIVITY MEASURES ARE IN PLACE FOR CONTRACT CREWS?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q15.1

Response

Budget Oversight by Contract Coordinators and Schedule Adherence

Most wotk is contracted on a fixed bid or unit price basis and we do not routinely measure contract crew productivity. If contractors are performing work on a time and equipment basis, we may request daily time and work reporting statistics to help assess their productivity.

Quality of work and adherence to schedule

Same as above; unit based contract

Meeting deadlines, contract bid within budgeted amounts set by engineering.

Actual vs. Estimate, Tendering work (market costs), pre approval for extras.

actuals versus in hours estimate, unit bid and firm bids

unit price contracting for low level work only

Estimated to actual reports. Underground units on subdivision work

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16| DO YOU MANAGE CONTRACT CREWS DIFFERENTLY FROM IN-HOUSE CREWS?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q16.1

Response

Yes, the schedule milestones are different

Yes. Productivity and cost control is generally addressed up front through the work bidding process (fixed bid or unit prices). During work exeuction, our management processes focus mostly on quality, safety, schedule compliance, pay paperwork accuracy and customer satisfaction. For company crews, we need to directly manage employee performance, attendance, training and various other personnel administration issues as well as quality, safety, schedule compliance, paperwork accuracy and customer service.

Contract crews predominately report to the Project Management Group. They are awarded a job and work independantly to ensure proper resources and safe work practices. Contractor work is inspected to ensure that it meets CNP standards. Internal crews are managed by Operations Management and report to Crew Leaders. The work they perform is much more diverse & their progress and performance are supervised more closely, using automation, such as Mobile Data, as well as field inspections.

Yes, we manage the contractor forman and let them manage the individuals that make up the crews

Yes.

Contractors are managed similar to in-house crews

We try and use unit or firm bid for the majority of contracting

are not mixed with regular staff and is for low level work only

Inspector ratio is 5 crews to one inspector - bery similar to company crews

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17| WHAT MEASURES ARE EVALUATED WHEN CONTRACT CREWS ARE SEEKING TO EXTEND CONTRACTS OR EXPAND THEM?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q17.1

Response

The contractor has to gain approval through a review process

Various performance metrics in blanket contracts relating to work quality, schedule compliance and safety. Contractor evaluation forms are also prepared after completion of individual bid jobs and any time that a blanket crew has done a notably good or poor job of meeting our expectations.

Previous performance, quality of work, ability to reflect well on the reputation of the company

Safety, quality, cost, customer satisfaction, etc..

Engineering division determines all change orders.

safety, price, availability, resources

safety, unit price, inservices met

Labor and equipment rates are evaluated and compared to company

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18| HOW ARE YOU COMPARING COMPANY VS. CONTRACT WORK AND HOW DOES THAT AFFECT YOUR DECISION TO CONTRACT GOING FORWARD?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q18.1

Response

Watched very closely, based on capital vs O&M work budget

Compare contractor fixed price or unit price bids to our internal cost estimates for specific work scopes. We also monitor and compare cost per equivalent mile for company versus contract crews on large infrastructure projects. Contractors can generally match or beat our internal cost estimates, so this is influencing our long range staffing plans (we will probably shift more work to contractors as our workforce shrinks through attrition)

There is constant investigation & study to identify what work would best be completed by contractors and what should be done internally. There is also a constant need to ensure the balance of contractors to internal workers to ensure that in storm or emergency situations, the proper workforce, both internal & contract, are sufficient.

All categories in question 17 are measured for both and compared to each other

We evaluate the needs of the customer, costs of the project, and the availability of personnel.

Cost, quality of work and the ability to meet in service dates

normalize, compensating for overheads that are applied for in-house crews

benchmark to outside like for like

We look at contractor cost and resources availability to workloads

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19| HAVE YOU MADE ANY RECENT DECISIONS TO OUTSOURCE NEW CATEGORIES OF WORK?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q19.1

Response
Yes, dig pits for UG cable fault work
Yes, we have outsourced street light installation work and are now evaluating outsourcing of street light underground secondary fault locating and repairs.
Some engineering work has recently been outsourced.
No
Yes.
No, most work is completed with both in-house or contractor workforce with the exception of switching.
no
no
None

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20| KNOWLEDGE: [EXAMPLES: CREW MEMBERS SKILL LEVEL; FOREMAN LEADERSHIP; NECESSARY KNOWLEDGE IN SUPPORT ORGANIZATION]:

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q20.1

Response

Training programs, refreshers classes, Field Bulletins, Procedure Change Notifications

Safety certification training and assessments for crew leads; cable splicing and termination training and assessments for all overhead and URD line personnel.

Mentoring. Movement from one territory to another to gain opportunities to learn to operate & maintain new types of field equipment. Crew leaders cycle through Dispatch Control to lead approximately 30 troubleshooters while learning how the Dispatch Control Center runs & the issues they face. Dispatch Control personnel ride with troubleshooters & line crews as part of their training to help them understand the issues, responsibilities, & safety aspects of the work performed by field personnel. Personnel are encouraged to seek formal education at local or on line universities. Formal in house classes required for all new supervisors. Company has an outstanding internal training program called CNP University. Mandatory classes, such as Code of Conduct, Pandemic Preparedness, & Smith Driving are taken via on line CNP University applications. Employees can access the University at work or from an Internet connection. Many on line, interactive classes are offered that are meant to develop leadership skills, promote teamwork, proper communication techniques, and dealing with difficult people or circumstances. CNP University offers sattelite conferences and webinars on various subjects.

Apprenice Program; Degree Program, Customer Sensitivity Training; Computer Skills Training

Several free courses are offered to help improve soft skills for the field personnel.

Succession and development plans for crews and management and support functions. Review of foremen profile, skill requirements, definition of new role, etc..

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We have a very experienced, knowledgeable and highly skilled group of workers and we solicit their input and participation when making changes.

Constant coaching by supervisors for those that are observed to be needing upgraded training. Cross zone work process inspection by supervisors with feedback.

Electric Refresher courses

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21| INFORMATION: [EXAMPLES: PROPER JOB PRINTS; UP-TO-DATE STANDARDS; RELEVANT JOB INFORMATION RELAYED; SHARING FUTURE PLANS]:

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q21.1

Response

Management Model, Procedures within, Cegis designs, Operations Management Systems (OMS)

Mapping information and Standards documentation can be accessed on mobile computers -- updates are distributed via CD

Work orders & standards can be accessed on line. Printed maps or drawings are delivered to the crew as part of the work order package. It has become common practice to have subject matter experts to attend Operations meetings to share information about new equipment, new procedures, HR policies, etc. Many processes that were handled by phone or radio in the past are now on line processes or forms are emailed are faxed to help ensure everyone is on the same page & reduce mis-communication. Emails & corporate publications are used to keep employees updated on information that could impact their jobs or the company in general. Several off site meetings are held annually so that several hundred employees are able to hear about current status and future plans of the different branches of the corporation from a panel of executives, including the CIO & CEO. Each of these off site meeting concludes with the panel of executives answering questions from the audience.

Computer Skills Training; process review

Meetings are frequently held to keep personnel informed.

Daily job review and planning before setting out to the field. Review of propoer documentation, plans, norms and standards to be used. Frequent review and communication of new or updated standards. The local planning unit (a pilot projetct at time of writing) will ensure review of future plans and sharing of such with the operating crews.

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Information is communicated down utilizing employee participation conference calls and elevator speeches to strive to consistency deliver the information.

Review revised job documents monthly.

None

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22| REWARDS: [EXAMPLES: RECOGNITION FOR GOOD WORK; CONSEQUENCES FOR POOR PERFORMANCE]:

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q22.1

Response

101 club, individual performance awards. Discipline through MARC principles

We do no have a formal incentive program for our union represented employees. We do have a "Quick Thanks" prgram where any employee may receive a nominal reward (e.g., a set of movie passes) for going above an beyond normal work expectations. We also provide group or individual recognitions for a job well done and occasional small group rewards (e.g., a lunch) provided by supervisor when key group goals or milestones are achieved. Individual coaching, counselling and discipline is used to address poor performance.

Crews or troubleshooters can receive small rewards when management shows up on a job for an unexpected safety observation. A formal mid-year & annual performance & leadership development review helps the employee understand their strengths & what skills can use improvement. It is management's job to help the employee find ways to improve their performance. The culture is changing to encourage employees to share near miss or safety information without fear of reprisal. It Happened To Me is a new program that allows employees to submit a story with or without identifying themselves.

Luncheons

Revamping of the Light Power & Pride Awards has spurred renew interest in productivity.

No formal reward system (suggestion or otherwise). However, good performance is recognized locally by foremen and mid level managers, occasionally. As for consequences for poor performance, if repetiitve and and continual, we make use of the dispositions of our collective contracts.

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Rewards are built into yearly gain sharing and performance management programs. Poor performers are dealt with through a progressive discipline process.

non for good work, performance management for poor

None

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23| AUTHORITY: [EXAMPLES: CREW HAS THE ABILITY TO QUESTION DESIGN; AVOID UNSAFE PRACTICE; GET ADDITIONAL MATERIAL OR HELP AS NEEDED]:

	Responses	Comments
Total Participants	18	
Number of Respondants	10	

Calculation used

Q23.1

Response
Promote questioning attitude on all designs - Crews encouraged to stop work when unsafe
Crews have authority to stop work and/or request additional help if there are safety issues. Crews also have ability to modify designs but are expected to discuss modifications with designer before making the change and reason for modifications are to be documented.
Field personnel may question, request more information, or ask for help for any aspect of their work. The crew leader is the first person that should be approached with these issues & it is the crew leader's job to bring about a satisfactory resolution.
Encourage personnel to questions authority and make field changes when necessary
During most meetings, all personnel are urged to provide input and work on committees to improve the workplace.
Generally, yes for all of the above. Our organization has encouraged our crews to take on more responsibility within the framework of their duties
Line and design are one group and work closely. Staff are encouraged to speak up especially if their concerns are related to safety.
For safety items crew has full authority.
governed by strict standards monitored by an outside government agency. Regulation 22/04
Crews and call in at anytime and stop a job for safety reasons.

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24| INTEGRATION: [WHAT INTEGRATION HAS BEEN DONE BETWEEN TRANSMISSION, DISTRIBUTION AND SUBSTATIONS?]:

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q24.1

Response

All share equally in programs, processes, procedures & Metrics

Troubleshooters are used for switching activities across tranmission, substations and distribution lines. From a construction and maintenance perspective the three functions operate autonomously in most respects and transmission is handled by a separate company.

Yearly business plans are developed & studied for dependencies. If a distribution business plan action item depends on work from transmission or substation, their business plan must have an associated action item with synchronized completion dates. This advanced planning process leads to conference calls and meetings to insure issues are identified and addressed. As work begins, all parties associated with the job have representation at the weekly priority meetings.

Minimal; some Distribution Management personnel

On as a per-needed basis. We have started to integrate the Customet and distribution first.

Unknown

our remote Zones do both Tx mtce and all Dx, more populus Zones are split all Dx and all mtce Tx. Stations is a separate LOB.

None

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25| PLEASE DESCRIBE ANY OTHER ORGANIZATION CHANGE INITIATIVES UNDERWAY THAT AFFECT YOUR FIELD FORCES:

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q25.1

Response

Mobile Dispatch, Switching Improvement,

None

More and more, field forces are included in committees, study groups, and new process launches. This not only breeds buy in, but is also an excellent tool for identifying leadership skills and talent of individuals to consider for succession plans.

The merging of work between the North and South service areas is being moved, but with resistance from some personnel.

Local or regional planning cell to review daily and monthly schedules

" Integrated planning and scheduling are specialized functions, enabled by dedicated resources, consistent processes, and improved applications. This initiative will deploy planning capabilities to develop an integrated, consolidated, and rolling forecast across all work types for multiple time horizons. It will also transfer the scheduling and work assignment duties from Line Managers to dedicated Schedulers. Transforming Design - Simplify, standardize, and segment design work. Standard design templates will be implemented, and there will be greater work specialization, segmentation, reassignment of non-design activities, and clustered teams for some types of work. Fully integrated design tools utilizing compatible units with links to work management and other systems will be deployed Leadership - Enhance performance management frameworks, consistent governance and continuous improvement processes, and improved leadership capability in order to realize and sustain the change. Enable line managers and supervisors to focus primarily on safety, work throughput of their crews or staff, quality and performance management by reassigning administrative duties and providing leadership training.

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26| DESCRIBE IMPORTANT NEW SAFETY OR QUALITY INITIATIVES UNDERWAY.

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q26.1

Response

Target zero safety - Top decile performance

New company safety strategy is being developed. Expect greater emphasis on formal risk analyses of jobs and enhanced safety leadership training for supervisors and crew leads.

It Happened To Me is a new program that allows field personnel to report near misses, with or without identifying themselves. These stories are published via email and posted on service center bulliten boards. These lead to topics for discussion in scheduled safety meetings. Support organizations, such as engineering, whose employees drive on company business and go into the field are part of a culture change that brings everyone into the safety process by awarding employees for voluntary observations to ensure safe driving, safe field & office work practices (office observations including lifting & other common practices that can cause injury if done incorrectly), and safe office conditions (check for spills, carpet tears, fire hazards, etc.). The observer turns in a report which tells what they found, what concerns were expressed, and how the issue was resolved. The observed party is not identified. The whole culture is changing in Operations and the support areas to get the message across that management and co-workers genuinely care about your safety and want to ensure that they are surrounded by people who care about what happens to them. Safety is a topic of discussion at every meeting, every tailboard, and in everyday conversations. Emails are sent to remind everyone of events that may pose a problem that day - like it's the first or last day of school, weather hazards, etc. It's amazing to walk the halls or the dock and hear the conversations that these reminders spark.

Contractor mangement Program- more stringenet requirements for monitoring, testing, and controlling contractors

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Culture Change Initiative is growing and its' purpose is being embraced by our personnel.

Quality: implementation of an Efficiency and Quality unit responsible to initiate cost reductions and also to monitor the quality levels in our work performance, measured by the number of non conformities, cost of non quality and adherence to the norms and standards.

Safety by Design - Review and update design and construction standards (materials, equipment, work methods, etc.) to embed safety within the full lifecycle. Work with EARG to introduce safety by design into capital replacement programs. Establish safety governance, clear metrics, target safety improvements, and consistent processes to monitor safety programs

Revised our Job Planning documents. Introduction of Regulation 22/04 and the monitor for compliance by an outside government agency.

Single Safety program

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27| WHAT NEW TRAINING INITIATIVES ARE UNDERWAY?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q27.1

Response

Work Planner Training, Switching Request Training

Developing new safety leadership training programs for first line supervisors and crew leads.

Helpers are being hired & as new apprentices enter the workforce, their formal training must be throughly supported by their on the job training. This makes seasoned workers take the time to think about what they are doing so that they demonstrate and teach safe, efficient work practices.

Customer sensitivity training- to address growing energy crisis and customer frustrations; new Apprentice program

Centralizing safety training is underway but is meeting some resistance.

Review and upgrade of the training material is on-going. Reduction of the training period for the linesmen. Training and refresher courses in our Code as an ongoing process

Designer training. Looking to enhance Designer training through online, video and help desk metoring. Jobsite planning and hazard awareness training for field crews.

we are at a 4 to 1 ratio in our Line Business. Strategy for keeping the apprentices seperated from seasoned veterans so they can be taught and work as per the proper policies and procedures. The apprentices also, through peer pressure, challenge each other

None

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2008 T&D Report Distribution Financial

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DISTRIBUTION LINE O&M EXPENSE PER END-USE CUSTOMER



Mean Quartile	
Mean	$87.66
Quartile 1	$61.06
Quartile 2:	$81.09
Quartile 3:	$108.42

Comments

Calculation used

Q5.8A / (T&D Dist End Use Customers)

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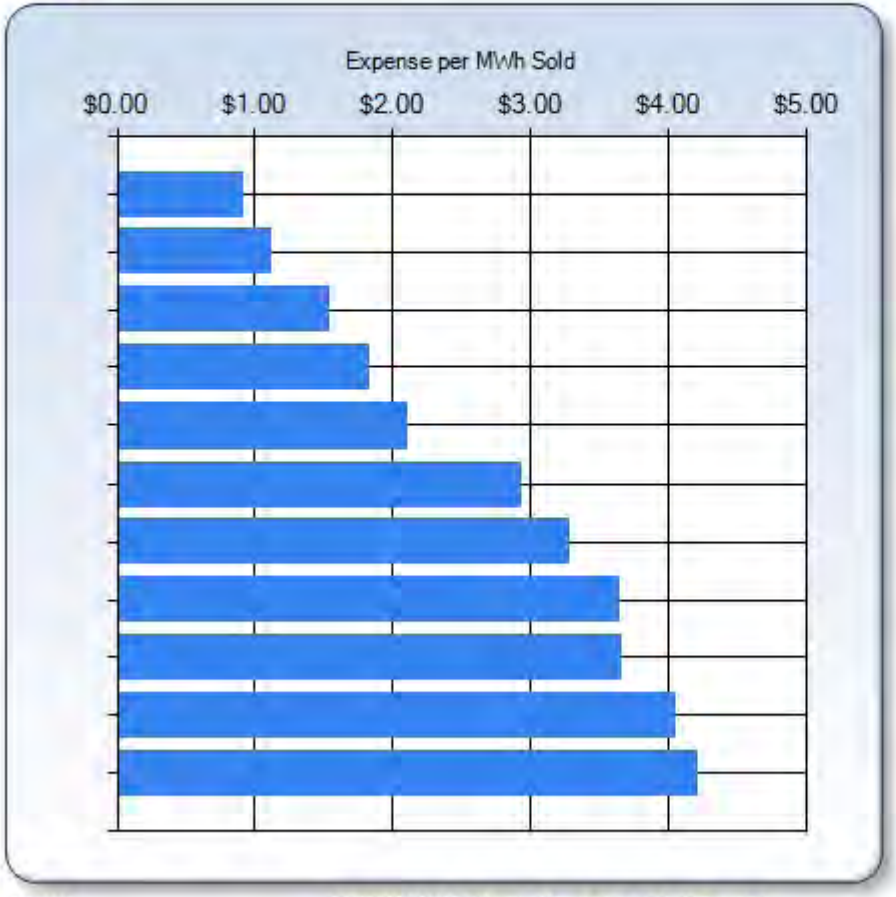
DISTRIBUTION LINES O&M EXPENSE PER MWH SOLD



Mean Quartile	
Mean	$2.67
Quartile 1	$1.69
Quartile 2:	$2.94
Quartile 3:	$3.66

Comments

Calculation used

Q5.8A / Q3.1A

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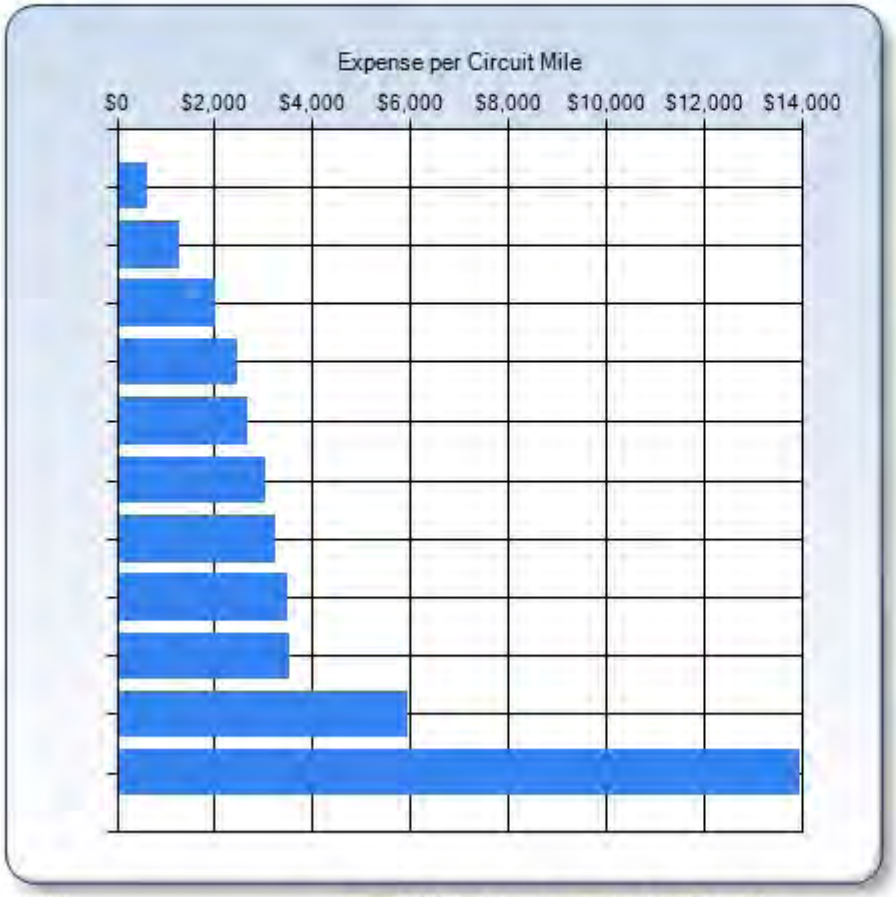
DISTRIBUTION LINES O&M EXPENSE PER CIRCUIT MILE



Mean Quartile	
Mean	$3,851
Quartile 1	$2,241
Quartile 2:	$3,047
Quartile 3:	$3,503

Comments

Calculation used

Q5.8A / (Dist Circ Miles)

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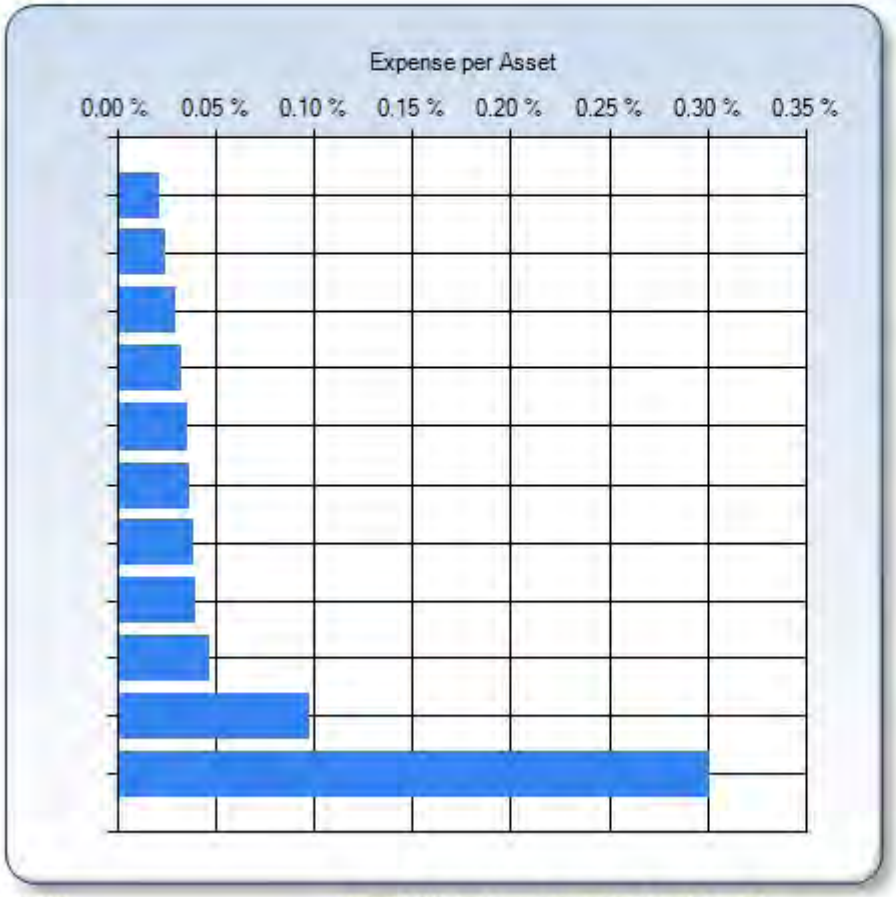
DISTRIBUTION LINES O&M EXPENSE PER ASSET



Mean Quartile	
Mean	0.064 %
Quartile 1	0.032 %
Quartile 2:	0.037 %
Quartile 3:	0.043 %

Comments

Calculation used

Q5.8A / Q16.1A

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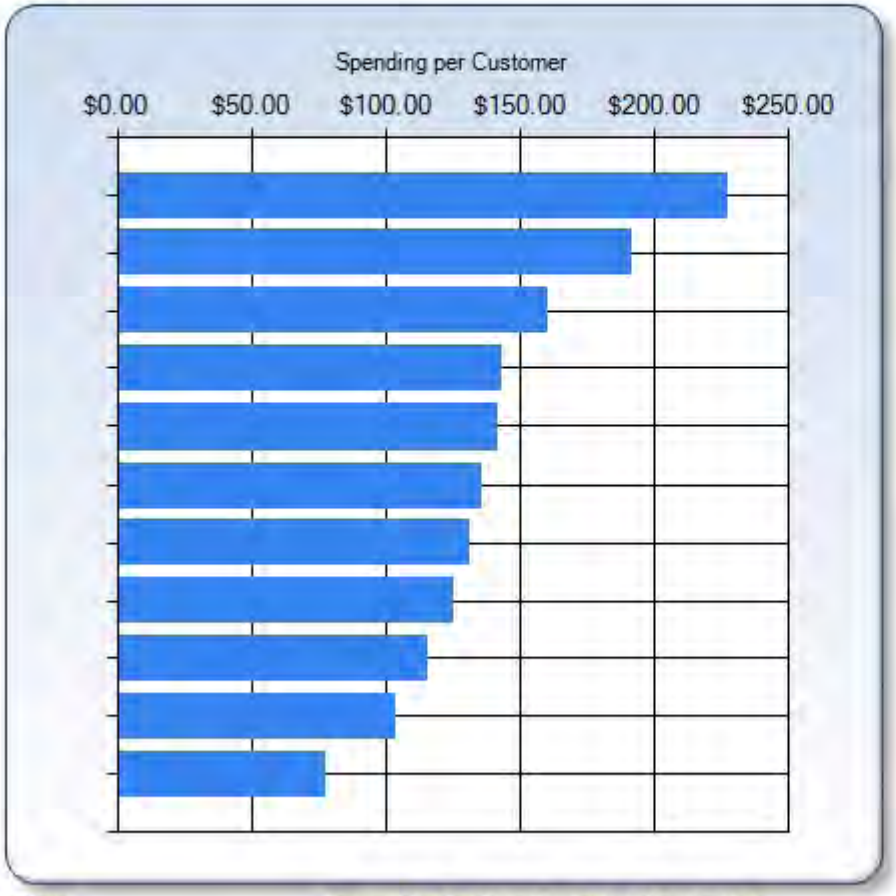
DISTRIBUTION LINE CAPITAL SPENDING PER END-USE CUSTOMER



Mean Quartile	
Mean	$141.68
Quartile 1	$152.18
Quartile 2:	$136.13
Quartile 3:	$120.83

Comments

Calculation used

Q1.7A / (T&D Dist End Use Customers)

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DISTRIBUTION LINES CAPITAL SPENDING PER ASSET



Mean Quartile	
Mean	$0.12
Quartile 1	$0.08
Quartile 2:	$0.06
Quartile 3:	$0.05

Comments

Calculation used

Q1.7A / Q16.1A

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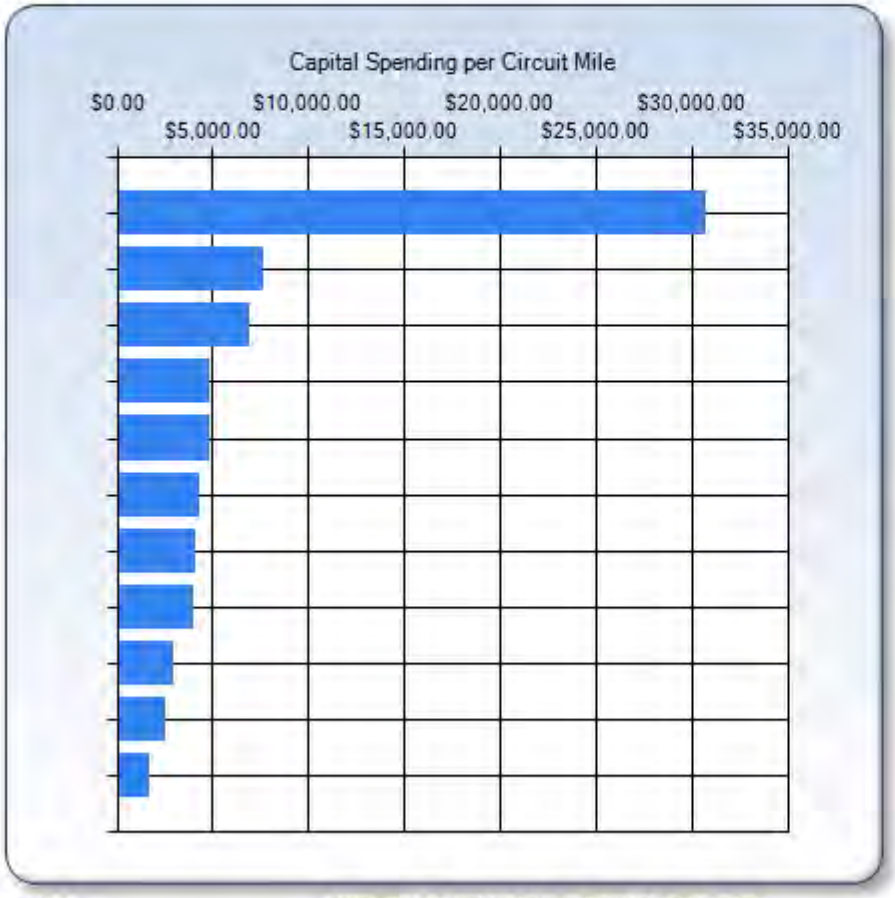
DISTRIBUTION LINE CAPITAL SPENDING PER CIRCUIT MILE



Mean Quartile	
Mean	$6,808.56
Quartile 1	$5,891.11
Quartile 2:	$4,301.88
Quartile 3:	$3,532.09

Comments

Calculation used

Q1.7A / (Dist Circ Miles)

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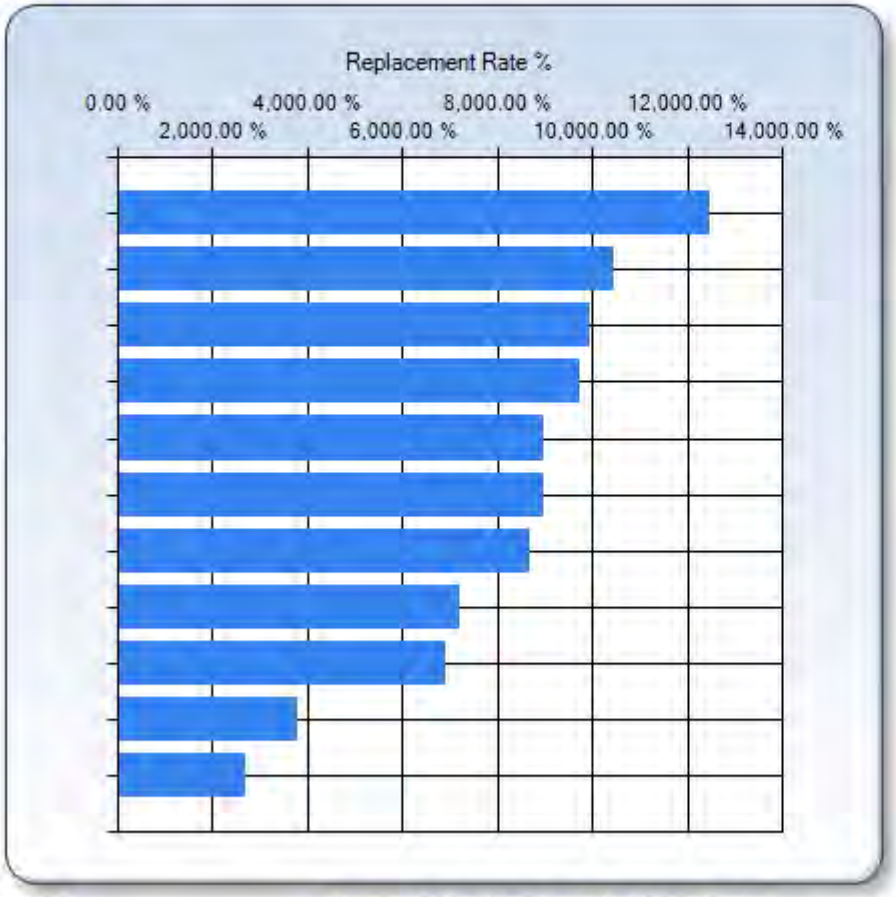
DISTRIBUTION LINE CAPITAL SPENDING LESS NEW BUSINESS PER END-USE CUSTOMER



Mean Quartile	
Mean	8,173.15 %
Quartile 1	9,852.30 %
Quartile 2:	8,962.78 %
Quartile 3:	7,057.69 %

Comments

Calculation used

(Q1.7A - Q9.1A) / (T&D Dist End Use Customers) * 100

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DISTRIBUTION LINE CAPITAL SPENDING LESS NEW BUSINESS PER ASSET



Mean Quartile	
Mean	5.97 %
Quartile 1	5.72 %
Quartile 2:	3.97 %
Quartile 3:	3.07 %

Comments

Calculation used

(Q1.7A - Q9.1A) / Q16.1A * 100

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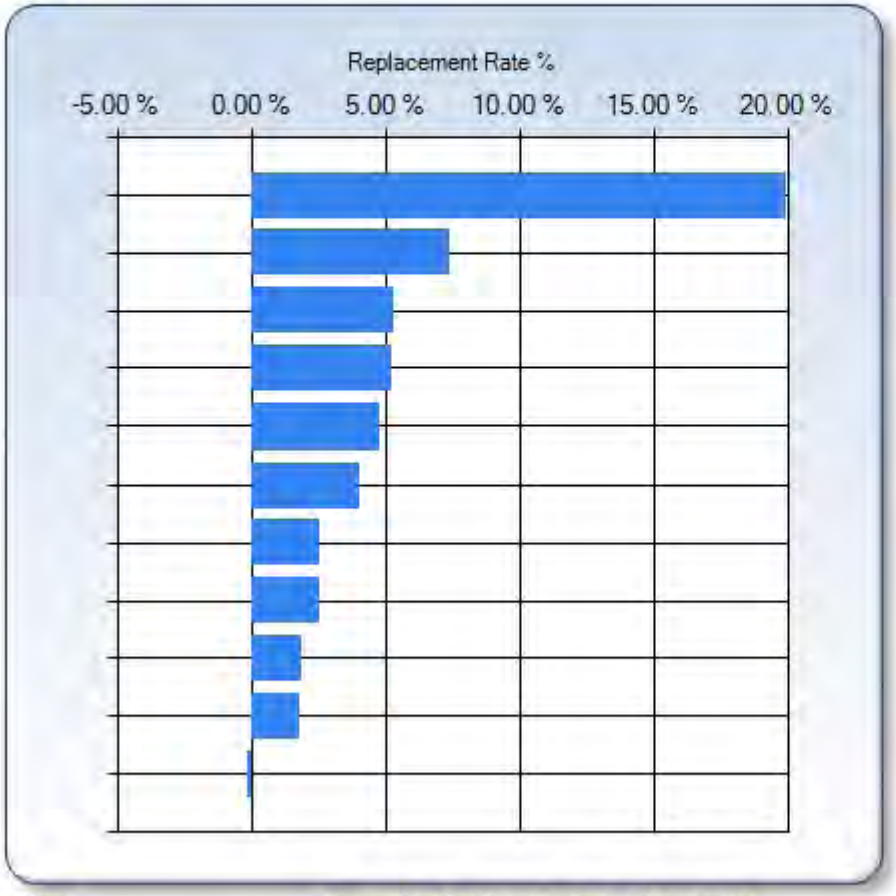
3-YR AVG DISTRIBUTION LINE CAPITAL SPENDING LESS NEW BUSINESS PER ASSET



Mean Quartile	
Mean	5.06 %
Quartile 1	5.28 %
Quartile 2:	4.07 %
Quartile 3:	2.25 %

Comments

Median asset replacement rate is 4.5%

Calculation used

((((Q1.7A - Q9.1A - Q1.5A) / Q16.1A) + ((Q1.7B - Q9.1B - Q1.5B) / Q16.1B) + ((Q1.7C - Q9.1C - Q1.5C) / Q16.1C)) / 3) * 100

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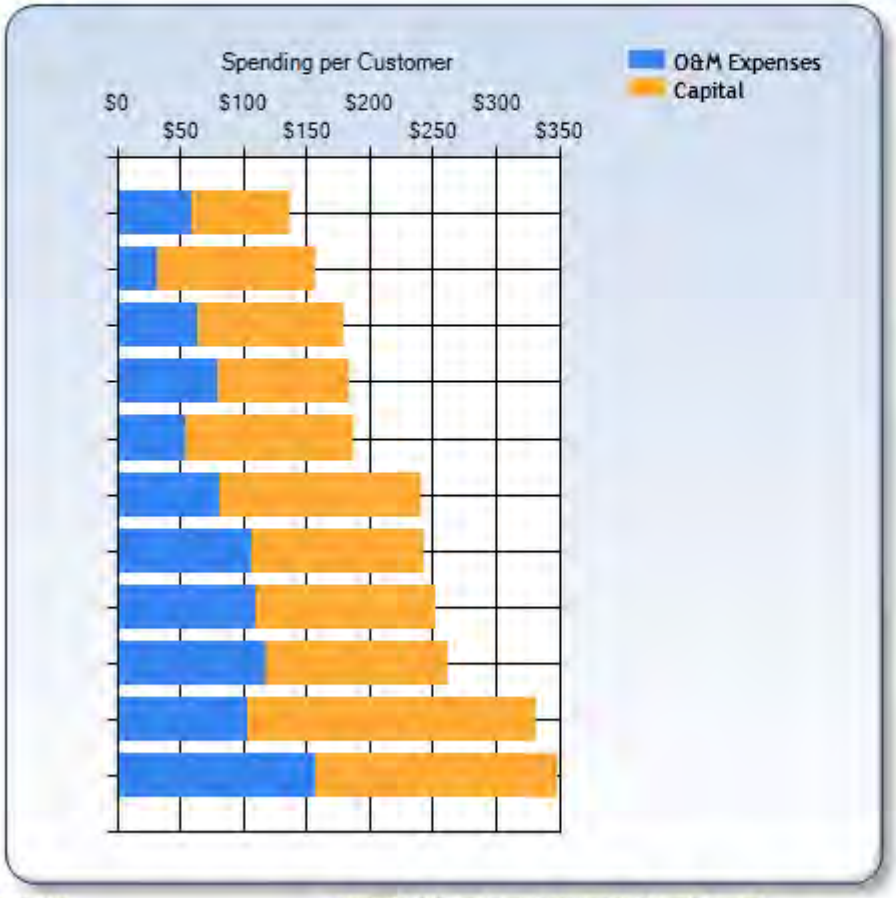
DISTRIBUTION LINE O&M & CAPITAL SPENDING PER END-USE CUSTOMER



Mean Quartile	
Mean	$229.34
Quartile 1	$181.39
Quartile 2:	$241.85
Quartile 3:	$256.54

Comments

Ratio of capital to O&M spending is less than 2:1, somew hat less than observed in previous years.

Calculation used

Q5.8A / (T&D Dist End Use Customers), Q1.7A / (T&D Dist End Use Customers)

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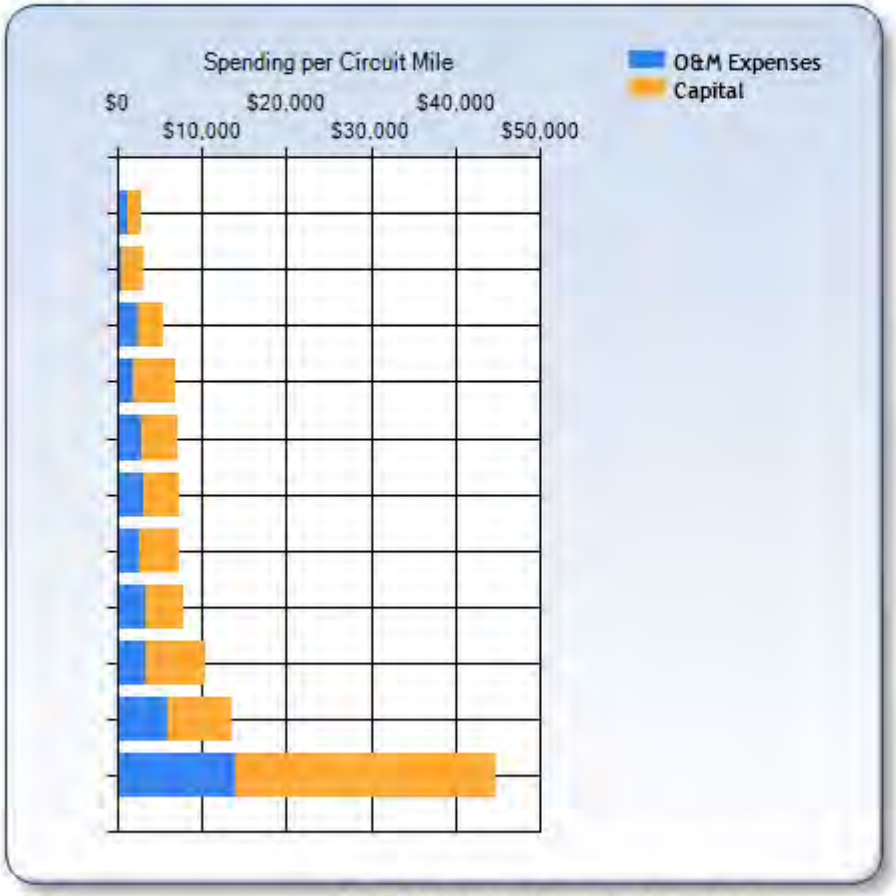
DISTRIBUTION LINE O&M & CAPITAL SPENDING PER CIRCUIT MILE



Mean Quartile	
Mean	$10,659
Quartile 1	$6,170
Quartile 2:	$7,415
Quartile 3:	$9,110

Comments

Ratio of capital to O&M spending is less than 2:1, somewhat less than observed in previous years.

Calculation used

Q5.8A / (Dist Circ Miles), Q1.7A / (Dist Circ Miles)

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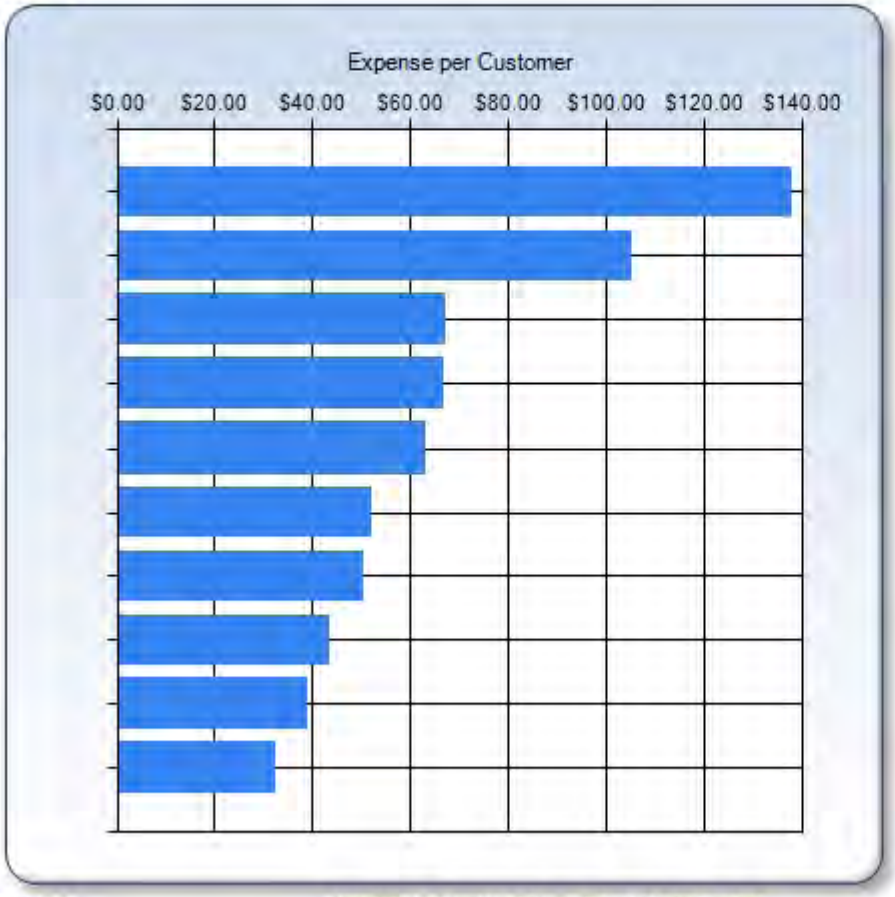
9| DISTRIBUTION NEW BUSINESS CAPITAL SPENDING PER END-USE CUSTOMER



Mean Quartile	
Mean	$65.94
Quartile 1	$67.36
Quartile 2:	$57.74
Quartile 3:	$45.43

Comments

Calculation used

Q9.1A / (T&D Dist End Use Customers)

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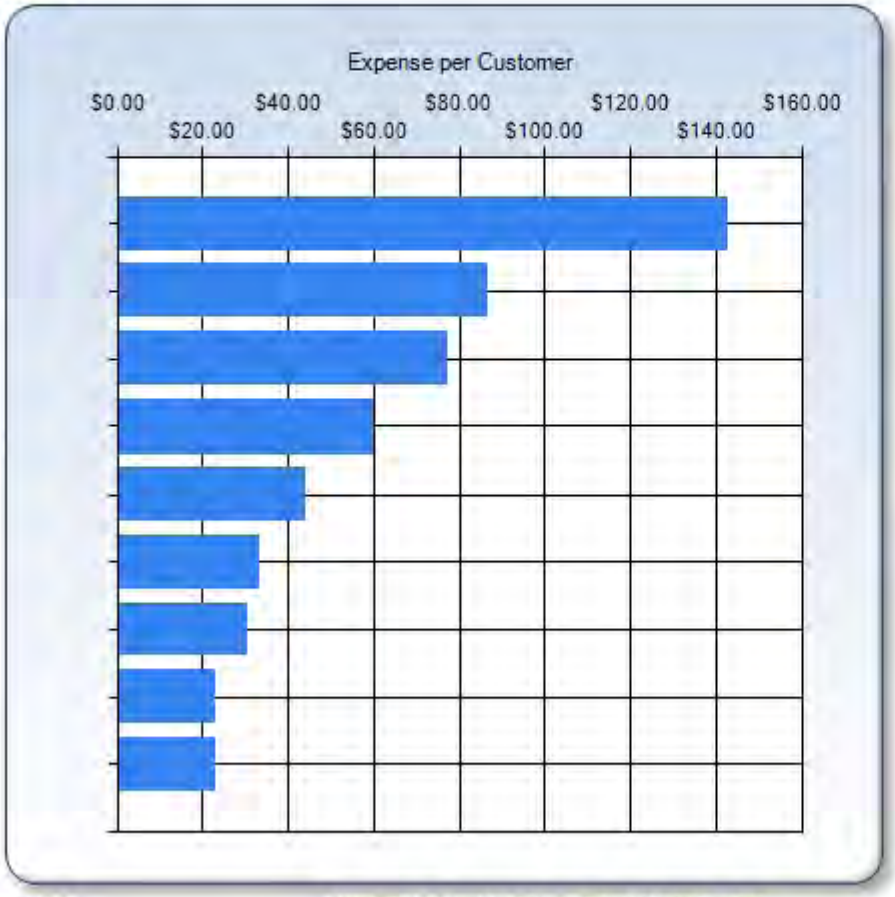
9| DISTRIBUTION INFRASTRUCTURE REPLACEMENT CAPITAL SPENDING PER END-USE CUSTOMER



Mean Quartile	
Mean	$57.93
Quartile 1	$77.48
Quartile 2:	$44.07
Quartile 3:	$30.60

Comments

Calculation used

Q9.2A / (T&D Dist End Use Customers)

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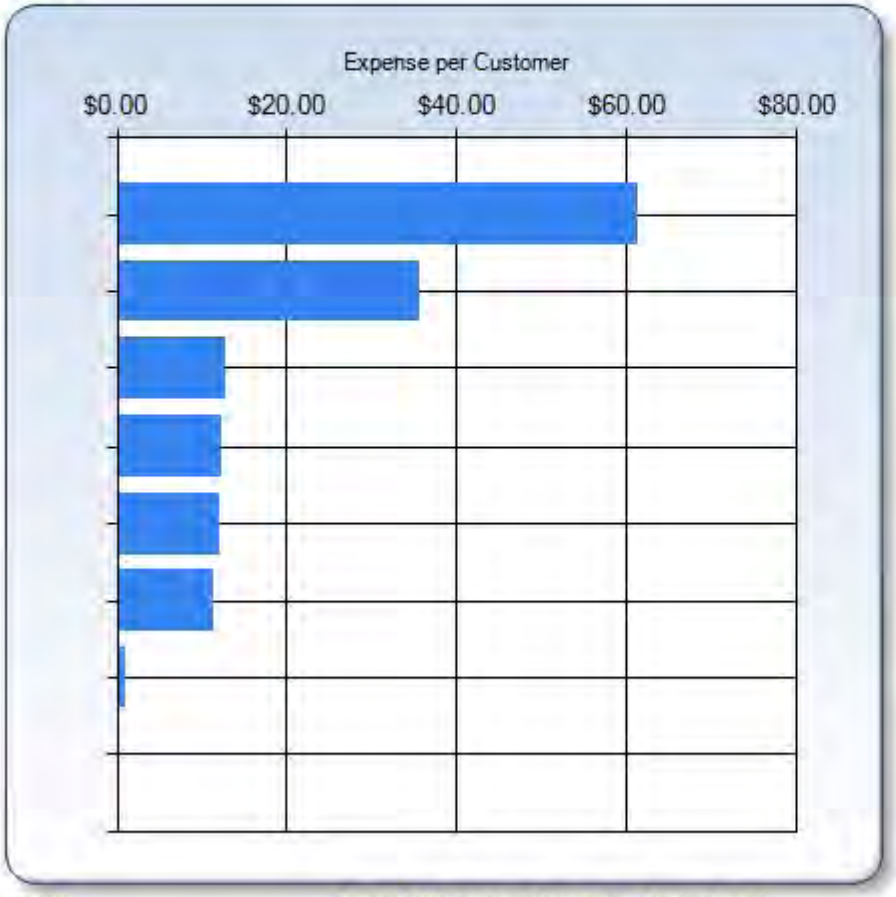
9| DISTRIBUTION TROUBLE RESPONSE CAPITAL SPENDING PER END-USE CUSTOMER



Mean Quartile	
Mean	$18.40
Quartile 1	$18.57
Quartile 2:	$12.30
Quartile 3:	$8.91

Comments

Calculation used

Q9.3A / (T&D Dist End Use Customers)

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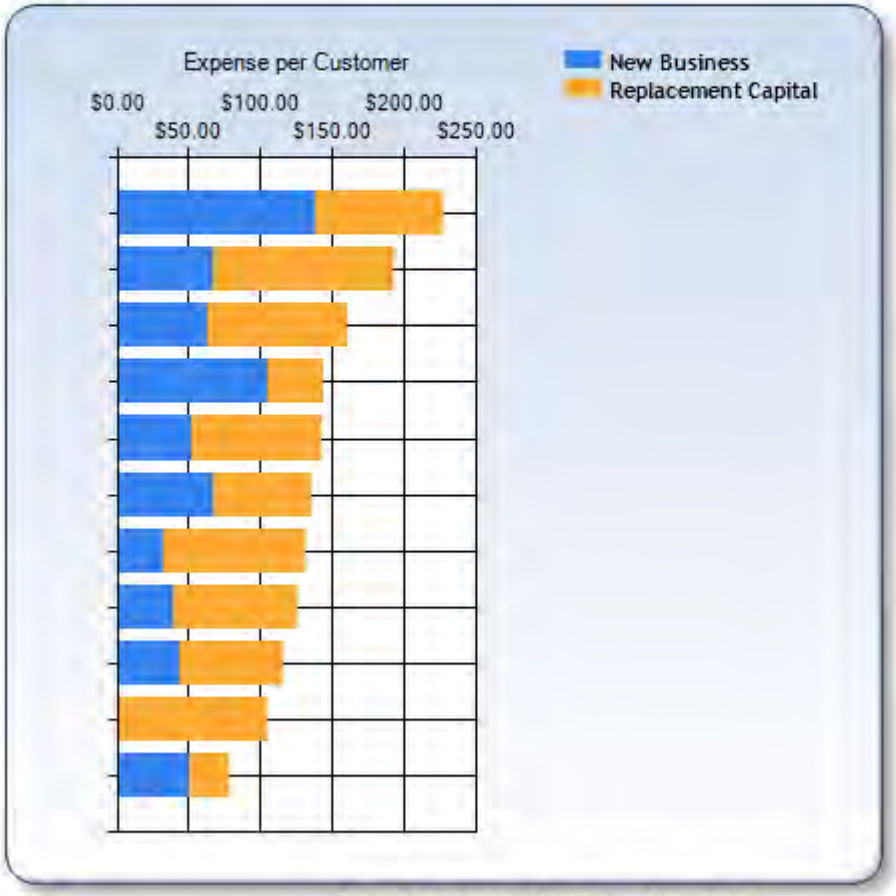
9| DISTRIBUTION CAPITAL SPENDING PER END-USE CUSTOMER



Mean Quartile	
Mean	$141.68
Quartile 1	$152.18
Quartile 2:	$136.13
Quartile 3:	$120.83

Comments

New Business median is about 50% of capital spend.

Calculation used

Q9.1A / (T&D Dist End Use Customers), (Q1.7A - Q9.1A) / (T&D Dist End Use Customers)

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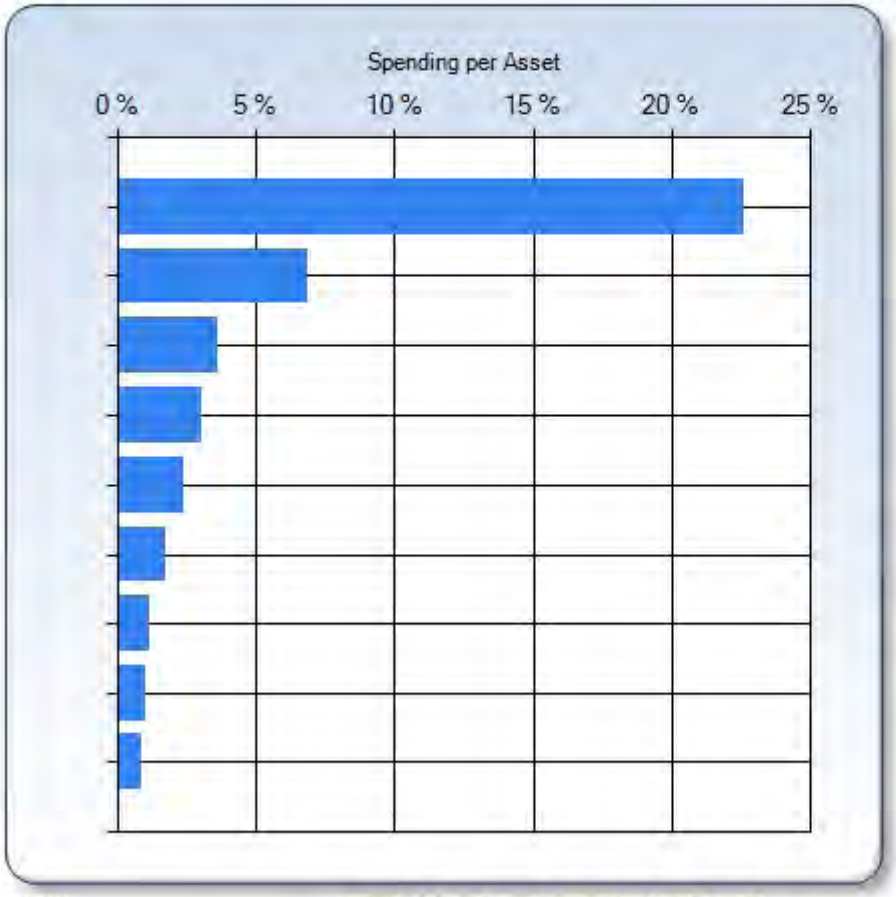
9| DISTRIBUTION INFRASTRUCTURE REPLACEMENT CAPITAL SPENDING PER DISTRIBUTION ASSETS



Mean Quartile	
Mean	5 %
Quartile 1	4 %
Quartile 2:	2 %
Quartile 3:	1 %

Comments

Calculation used

Q9.2A / Q16.1A * 100

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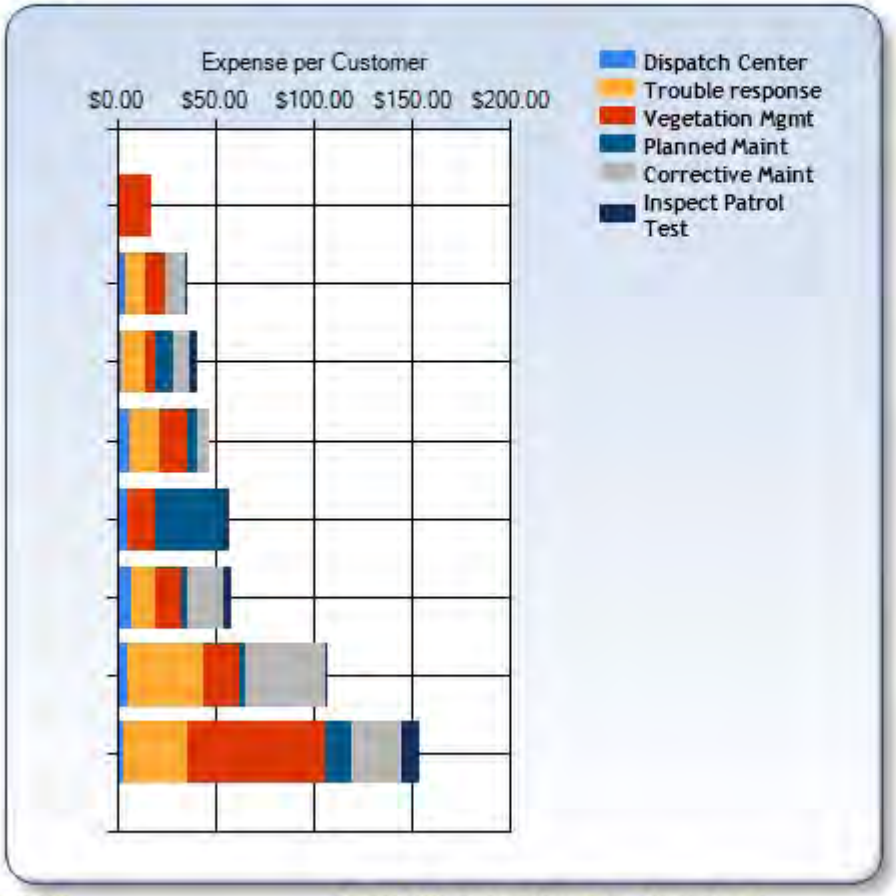
12| DISTRIBUTION LINE O&M EXPENSE BY ACTIVITY PER END-USE CUSTOMER



Mean Quartile	
Mean	$64.62
Quartile 1	$39.47
Quartile 2:	$52.26
Quartile 3:	$70.46

Comments

Calculation used

Q12.1A / (T&D Dist End Use Customers), Q12.2A / (T&D Dist End Use Customers), Q12.3A / (T&D Dist End Use Customers), Q12.4A / (T&D Dist End Use Customers), Q12.5A / (T&D Dist End Use Customers), Q12.6A / (T&D Dist End Use Customers)

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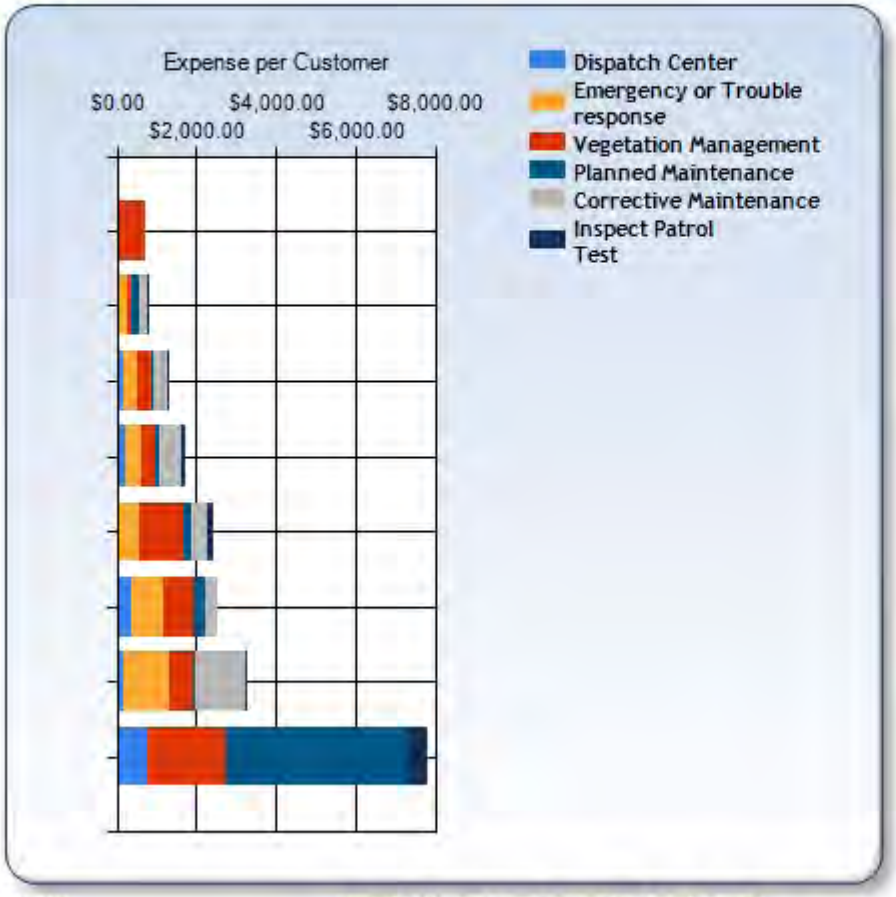
12| DISTRIBUTION LINES O&M EXPENSE BY ACTIVITY PER CIRCUIT MILE



Mean Quartile	
Mean	$2,577.65
Quartile 1	$1,166.79
Quartile 2:	$2,080.22
Quartile 3:	$2,720.35

Comments

Calculation used

Q12.1A / (Q9.2A + Q10.4A + Q10.5A), Q12.2A / (Q9.2A + Q10.4A + Q10.5A), Q12.3A / (Q9.2A + Q10.4A + Q10.5A), Q12.4A / (Q9.2A + Q10.4A + Q10.5A), Q12.5A / (Q9.2A + Q10.4A + Q10.5A), Q12.6A / (Q9.2A + Q10.4A + Q10.5A)

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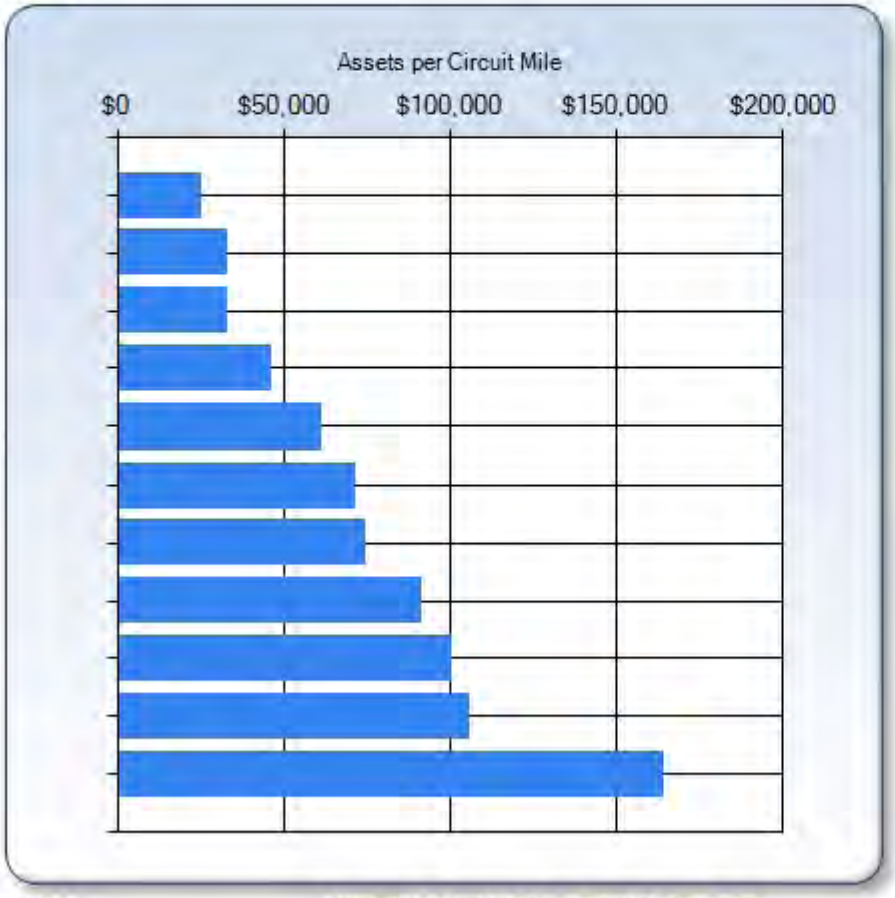
16| DISTRIBUTION LINES PLANT IN SERVICE PER DISTRIBUTION CIRCUIT MILE



Mean Quartile	
Mean	$73,645
Quartile 1	$39,998
Quartile 2:	$71,754
Quartile 3:	$96,193

Comments

Calculation used

Q16.1A / (Dist Circ Miles)

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16| DISTRIBUTION LINES PLANT IN SERVICE PER DISTRIBUTION END-USE CUSTOMER



Mean Quartile	
Mean	$2,074
Quartile 1	$1,485
Quartile 2:	$2,044
Quartile 3:	$2,505

Comments

Calculation used

Q16.1A / (T&D Dist End Use Customers)

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2008 T&D Report: Infrastructure Wellness - Distribution

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3| How do you use an 'actuarial' approach to understanding age of various critical critical components?

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8| How does condition impact on maintenance, reliability, and capacity goals?

9| How can an 'old' infrastructure withstand the needs of the intelligent grid?

10| Percent of Capacitors installed by decade

10| Percent of Poles installed by decade

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Average age of components: Poles

10| Percent of Services installed by decade

10| Percent of Transformers installed by decade

Average age of components: Transformers

10| Percent of Underground cable installed by decade

Average age of components: UG Cable

10| Percent of Underground Switches installed by decade

11| How do you use benchmarking data to compare your age of equipment to others?

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16| What is the role of the Asset Management organization in your decision-making?

17| What keeps you up at night worrying about your system?

18| Replacement programs underway Capacitors

18| Replacement programs underway Overhead Feeders

18| Replacement programs underway Poles

18| Replacement programs underway Transformers

18| Replacement programs underway Underground Feeders

18| Replacement programs underway Underground Switches

19| What are the classes of equipment that are becoming problematic?

21| What is the next class of assets that needs to be replaced [e.g. old style UG cable? Certain plastic materials]?

23| What analytic approaches do you use to predict replacement needs?

24| How are the decision criteria for repair versus replace determined?

25| How have you used the concepts embodied in 'Reliability Centered Maintenance'?

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INFRASTRUCTURE WELLNESS SELF ASSESSMENT: DISTRIBUTION

Total Respondents	8
A| Keep statistics on age of infrastructure	87.5%
B| Evaluate Replacement needs	87.5%
C| Condition based replacement	100%
D| Replacement programs for component classes	62.5%
E| Budget exceeds depreciation	12.5%
F| Appropriate spending for replacement	50%

Comments

Calculation used

Q.1A, Q.1A, Q.1A, Q.1A, Q.1A, Q.1A

Legends								
A| Keep statistics on age of infrastructure	♦		♦	♦	♦	♦	♦	♦
B| Evaluate Replacement needs	♦	♦	♦	♦	♦	♦		♦
C| Condition based replacement	♦	♦	♦	♦	♦	♦	♦	♦
D| Replacement programs for component classes	♦	♦		♦		♦		♦
E| Budget exceeds depreciation				♦				
F| Appropriate spending for replacement		♦	♦	♦			♦	

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1| HOW DO YOU MEASURE AGING OF YOUR DISTRIBUTION INFRASTRUCTURE [E.G. AT THE COMPONENT LEVEL]?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q1.1

Response

Age & condition of major components (transformers, conductor, poles, protective devices, RTU's etc.) tracked on an annual basis.

Installation by decade

Traked in equipment database; some older equipment-data unavailable

By periodical inspections, inspecting the components (more condition based then age based)

We measure the health of some components via condition assessment. If we don't know the age and there are no assessment techniques, we go by subject matter experts' (SME) suggestions.

For poles we have installed dates, for most other assets age determination is based on review of asset accounting data including total quantity placed in service in a given year

Line patrols,defect management, maintenance programs, data collection

At the component level, in years

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2| HOW DO YOU MAKE COMPARISONS BETWEEN DIFFERENT AREAS OF YOUR SYSTEM BASED ON AGE?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q2.1

Response

Vintages of equipment tend to align with system kV

NA

Condition is primary consideration; age and characteristics are secondary

Very little data on the age of the components is actually available. We plan to collect data on our OH system through sampling

We don't compare different areas based on age. We do condition asessments.

data collection-compilation of condition and age data by zone/area/feeder

We do not routinely compare age differences by system areas; focus is system-wide

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3| HOW DO YOU USE AN 'ACTUARIAL' APPROACH TO UNDERSTANDING AGE OF VARIOUS CRITICAL CRITICAL COMPONENTS.

	Responses	Comments
Total Participants	18	
Number of Respondants	0	

Calculation used

51542texttext

ID	Response

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3| HOW DO YOU USE AN 'ACTUARIAL' APPROACH TO UNDERSTANDING AGE OF VARIOUS CRITICAL CRITICAL COMPONENTS?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q3.1

Response

Hazard functions have been developed for substation transformers, poles & UG cable.

NA

We do not use an actuarial approach

On submarine cables, poles, we use weibull curves. The rest of the assets don't use actuarial approach.

Demographic models; Asset retirement models

While age is considered, condition & performance are focus of evaluation of crit. components

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4| SYSTEMATIC EVALUATION OF CONDITION OF CAPACITORS

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q4.5

Response
Annual inspection/maintenance program,
NA
Annual capacitor inspection program
inspection by systematic patrols
time based
inspection for PCB's, line patrols
10-year visual inspection on condition

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4| SYSTEMATIC EVALUATION OF CONDITION OF UNDERGROUND FEEDERS

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q4.3

Response
Annual reliability reviews,
NA
No systematic approach- dependent on field reports/inspection results
thermography inspection and patrol, high voltage test
cable assessment using leakage current levels, time domain reflectometry, IR and PD
Analyze fault data based on fuse points
maintenance programs
Prioritize & evaluate number of faults annually

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4| SYSTEMATIC EVALUATION OF CONDITION OF OVERHEAD FEEDERS

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q4.4

Response
"Integrated overhead maintenance program" (our forestry crews inspect overhead feeders when doing their program trims)
NA
No systematic approach- dependent on field reports/inspection results
inspection by systematic patrols
none
inspection programs and defects found as part of these programs
line patrols, maintenance programs, outage data
10-year visual inspection on condition

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4| SYSTEMATIC EVALUATION OF CONDITION OF TRANSFORMERS

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q4.2

Response

Ongoing condition monitoring & condition evaluation (monthly or by exception),

NA

No systematic approach- dependent on field reports/inspection results

inspection by systematic patrols

run to failure. For bigger transformer (500 and 750), we use dissolve gas analysis (DGA)

Line patrols, customer upgrades, PCB inspection

10-year cycle visual inspection (i.e. rust, damage)

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4| SYSTEMATIC EVALUATION OF CONDITION OF UNDERGROUND SWITCHES

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q4.6

Response
No program
NA
No systematic approach- dependent on field reports/inspection results
inspection by systematic patrols
time based
feedback from operations staff
NA
Visual inspection and operational tests

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5| PREDICTING CONDITION OF VARIOUS CRITICAL COMPONENTS BASED UPON OPERATING ENVIRONMENT OR OTHER MEASURABLE FACTORS - DIST

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q5.1

Response

Real-time oil/temperature monitoring for substation transformers, inspection data assimulated in substation maint. management softw are tool.

NA

No system w ide evaluations performed; prediction is transactional (performed at time of inspection or response to trouble)

overhead: maintenance remains preventive w ith periodical inspections, underground sw itches: nomber of closing on failure is recorded and a limit is imposed

based on importance of connected customers, environmental conditions (stressors, slopes) number of faults and SME

reliability statistics are analyzed at a feeder level to determine poor performing areas w hich are typically driven by condition / aging issues

Outage data/ Reliability analysis

Cable segments are evaluated/prioritized by the number of outages annually

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6| CHANGES MADE IN INSPECTION/REPLACEMENT PROGRAMS FOR CAPACITORS

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q6.5

Response
Applied know ledge from previous programs to prioritize more critical w ork.
NA
Annual capacitor inspection program.
No change
no change
No change
NA

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6| CHANGES MADE IN INSPECTION/REPLACEMENT PROGRAMS FOR TRANSFORMERS

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q6.2

Response
Applied know ledge from previous programs to prioritize more critical w ork.
NA
No change
No change
NA

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6| CHANGES MADE IN INSPECTION/REPLACEMENT PROGRAMS FOR POLES

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q6.1

Response

Applied know ledge from previous programs to prioritize more critical w ork.

NA

Budget approved for systematic pole inspection and replacement program- to be implemented in 2009.

Analysing the poles inspection program to be changed.

w e use cedar poles on selected areas (coastal).

10 year test and treat cycle implemented

No change

Began groundline (excavation) inspections in 2003

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6| CHANGES MADE IN INSPECTION/REPLACEMENT PROGRAMS FOR UNDERGROUND FEEDERS

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q6.3

Response
Applied know ledge from previous programs to prioritize more critical w ork.
NA
No change
no change
No change
Developed outage management query in 2006

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6| CHANGES MADE IN INSPECTION/REPLACEMENT PROGRAMS FOR UNDERGROUND SWITCHES

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q6.6

Response
Applied know ledge from previous programs to prioritize more critical w ork.
NA
No change
no change
added quarterly inspections of dow ntow n netw ork vaults
No change
NA

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6| CHANGES MADE IN INSPECTION/REPLACEMENT PROGRAMS FOR OVERHEAD FEEDERS

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q6.4

Response
Applied know ledge from previous programs to prioritize more critical w ork.
NA
No change
no change
No change
NA

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7| REALISTIC DESIGN LIFE FOR VARIOUS MAJOR CRITICAL COMPONENTS USED WHEN PLANNING SYSTEM REPLACEMENT [YEARS]

Total Respondents	7
Poles	50.86
Transformers	36.57
Underground Feeders	37.43
Overhead Feeders	46.67
Capacitors	34.29
Underground Switches	35.33

Comments

Calculation used

Q7.1, Q7.2, Q7.3, Q7.4, Q7.5, Q7.6

Legends							
Poles	55	40	50	46	70	50	45
Transformers	40	30	40	41	40	25	40
Underground Feeders	40	30	40	42	40	25	45
Overhead Feeders	40		50	45	70	25	50
Capacitors	40	30	40	45	30	25	30
Underground Switches	40	25		42	40	25	40

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8| HOW DOES CONDITION IMPACT ON MAINTENANCE, RELIABILITY, AND CAPACITY GOALS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q8.7

Response
Constrains amount available for capacity & reliability goals
NA
As condition decreases, maintenance, reliability, and capacity suffer
These is a strong link betw een condition and maintenance and reliability but w e didn't measure until now the influence.
condition plays a major role on maintenance and reliability. It provides a ranking tool w hen prioritizing inspection cycles and capital spending.
condition can be directly linked to maintenance costs and reliability performance
Poor condition results in increase maintenance costs, poorer reliability
Poor condition results in increased maintenance to fix reliability problems

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9| HOW CAN AN 'OLD' INFRASTRUCTURE WITHSTAND THE NEEDS OF THE INTELLIGENT GRID?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q9.8

Response

Devices have been replaced, and many more devices will need to be replaced.

We are trying to determine this now

The intelligent grid components (IEDs, Smart Meters, intelligence within software for automatic reconfiguration or Volt Var Control etc...) will have few impact, on the aging distribution infrastructure (Poles, cables, overhead conductors, switches Breakers...). The system infrastructure will get older and will need replacement and its life expectancy will better be improved by specific projects to improve the mechanical performance of the components. The intelligence may help to operate the system to its limits (e.g. loading of the cable and conductors). There is a concern about the life expectancy of the new "intelligent" component based on electronic components which typical life is rarely over 10 years.

Age of distribution system should have minimal impact on intelligent grid requirements

Old infrastructure provides the opportunity to replace end-of-life assets while at the same time upgrading technology

NA

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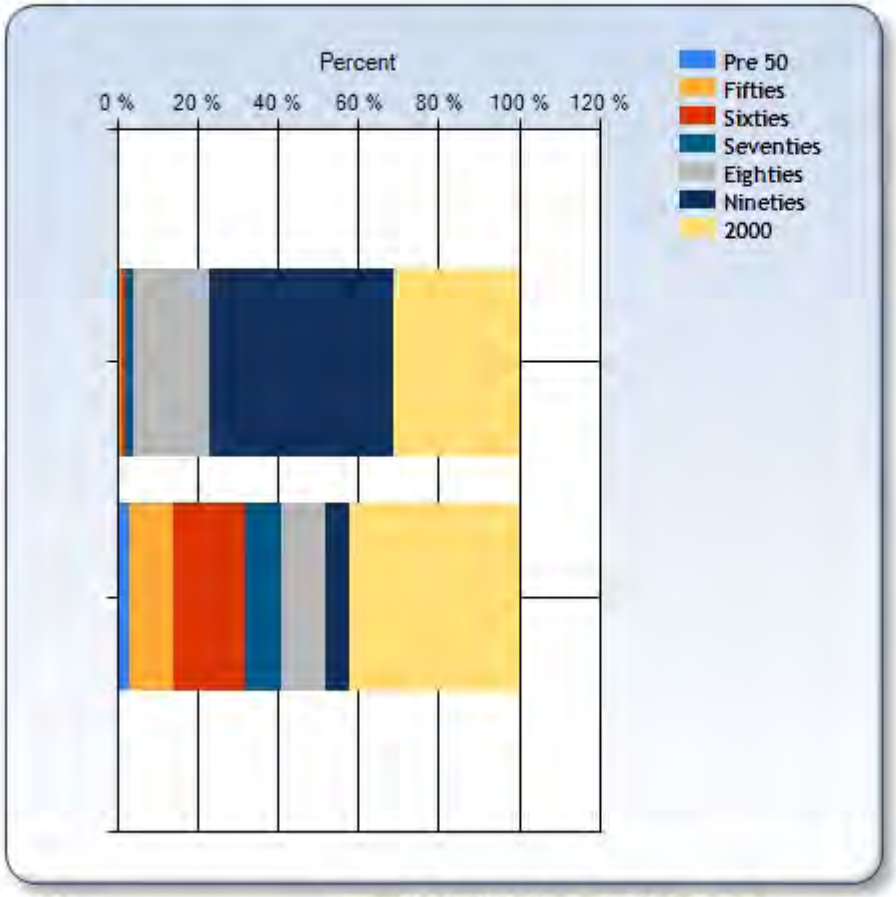
10| PERCENT OF CAPACITORS INSTALLED BY DECADE



Comments

Calculation used

Q10.3A, Q10.3B, Q10.4C, Q10.4D, Q10.4E, Q10.4F, Q10.4G

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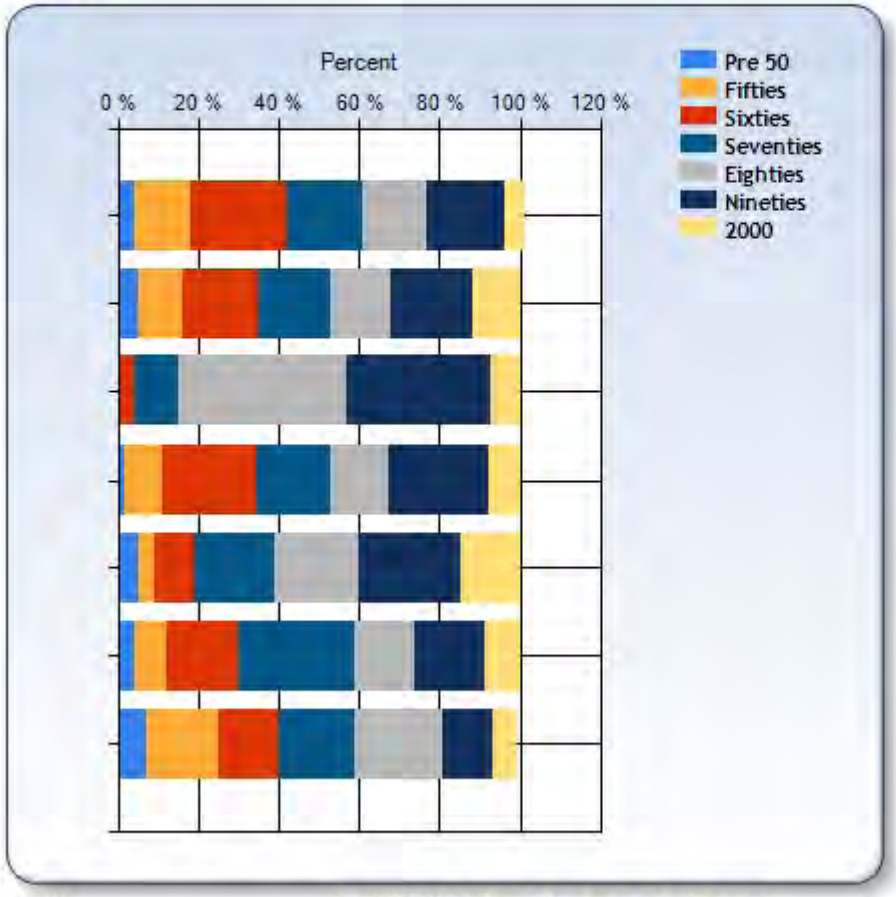
10| PERCENT OF POLES INSTALLED BY DECADE



Comments

Calculation used

Q10.1A, Q10.1B, Q10.1C, Q10.1D, Q10.1E, Q10.1F, Q10.1G

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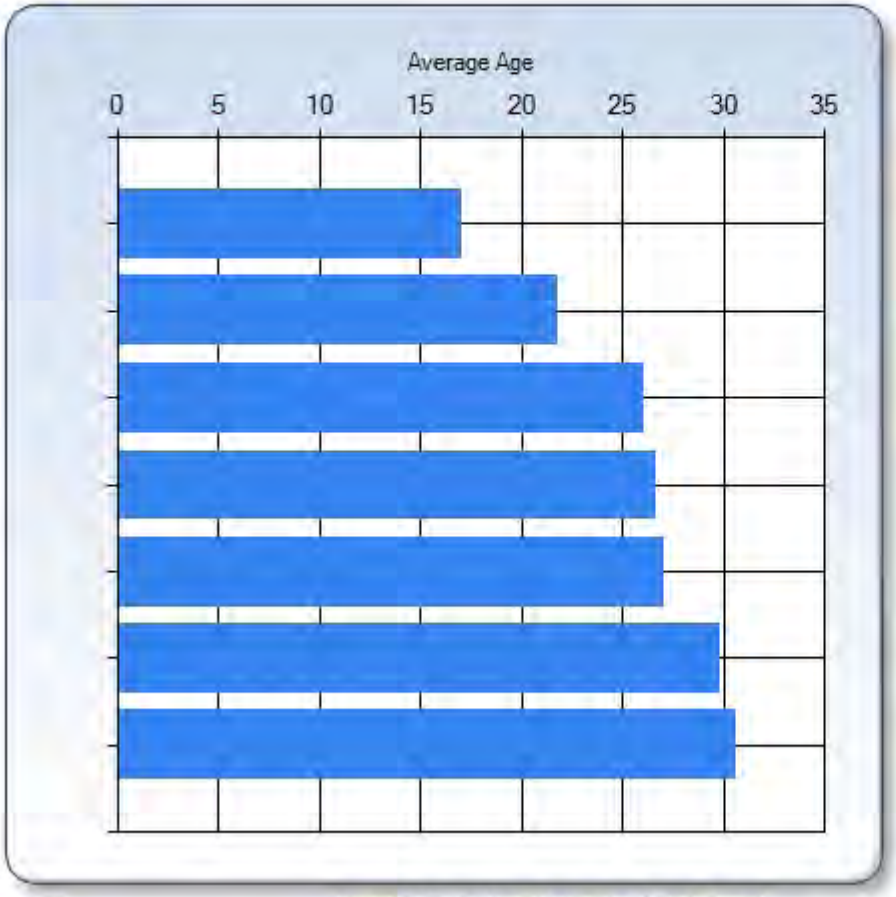
AVERAGE AGE OF COMPONENTS: POLES



Mean Quartile	
Mean	26
Quartile 1	24
Quartile 2:	27
Quartile 3:	28

Comments

Calculation used

(Q10.1A * 60 + Q10.1B * 50 + Q10.1C * 40 + Q10.1D * 30 + Q10.1E * 20 + Q10.1F * 10 + Q10.1G) / 100

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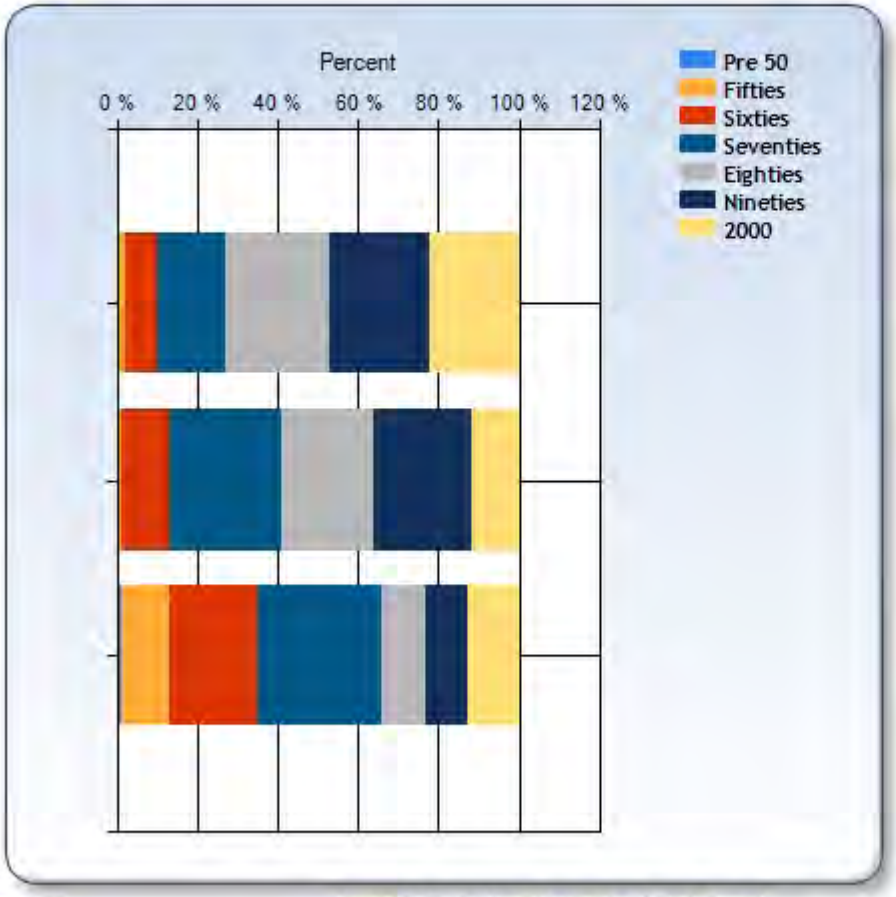
10| PERCENT OF SERVICES INSTALLED BY DECADE



Comments

Calculation used

Q10.5A, Q10.5B, Q10.6C, Q10.6D, Q10.6E, Q10.6F, Q10.6G

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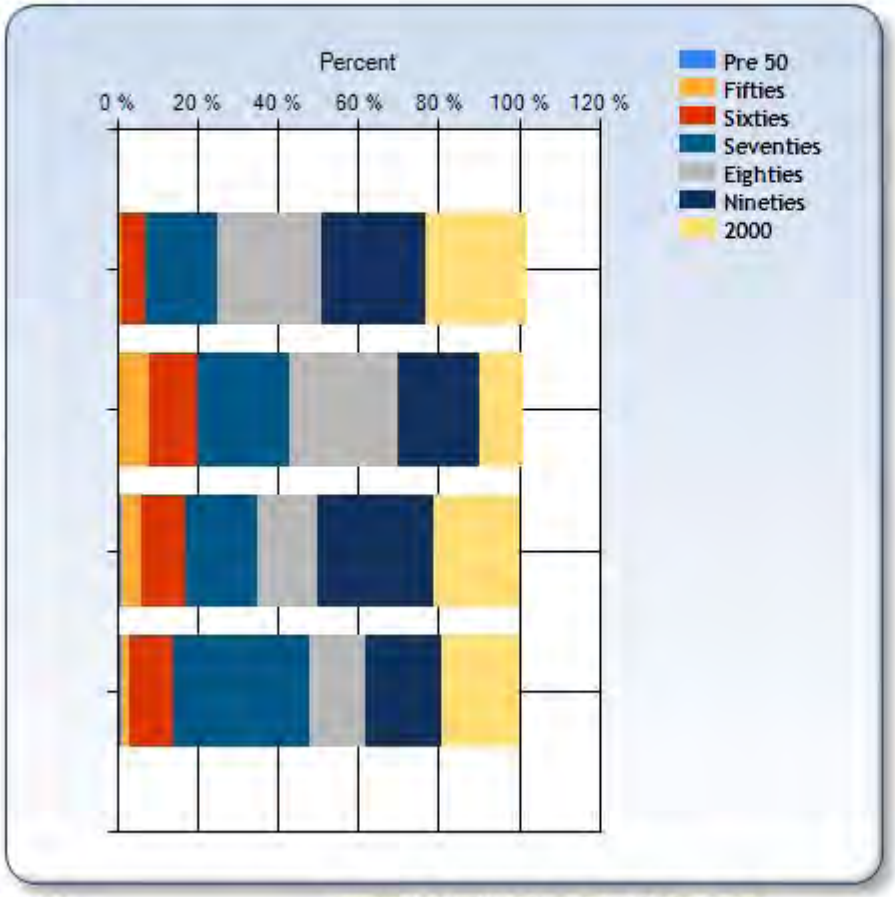
10| PERCENT OF TRANSFORMERS INSTALLED BY DECADE



Comments

Calculation used

Q10.1A, Q10.1B, Q10.2C, Q10.2D, Q10.2E, Q10.2F, Q10.2G

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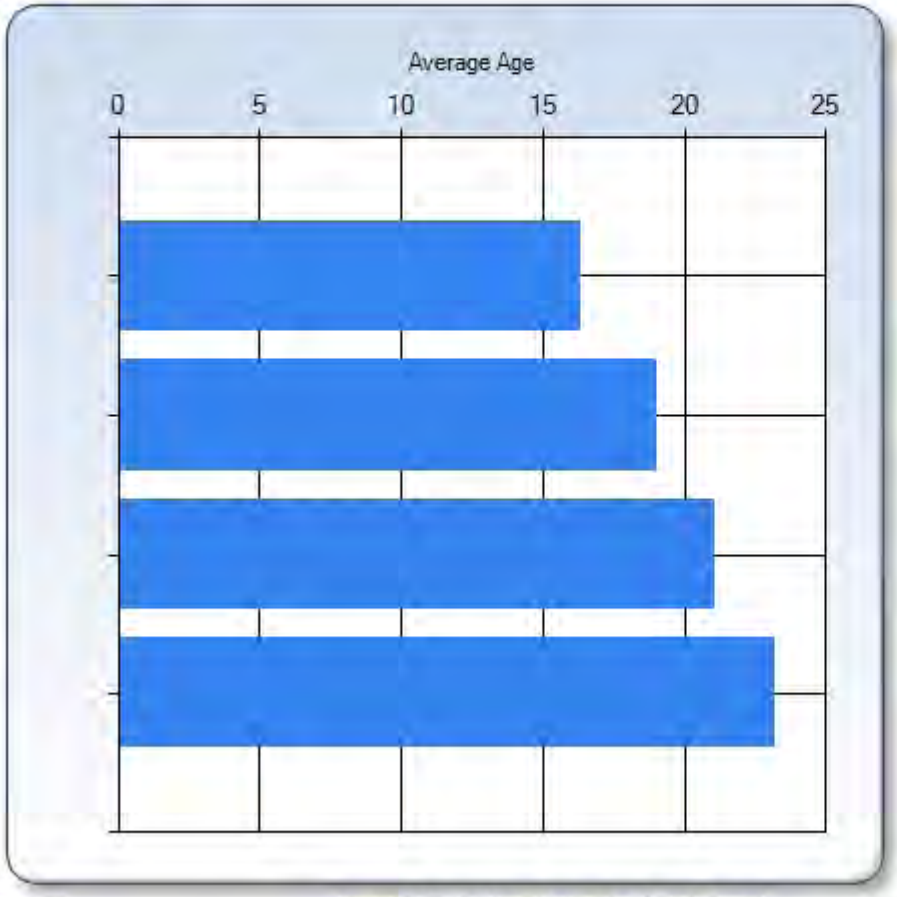
AVERAGE AGE OF COMPONENTS: TRANSFORMERS



Mean Quartile	
Mean	20
Quartile 1	18
Quartile 2:	20
Quartile 3:	22

Comments

Calculation used

(Q10.1A * 60 + Q10.1B * 50 + Q10.2C * 40 + Q10.2D * 30 + Q10.2E * 20 + Q10.2F * 10 + Q10.2G) / 100

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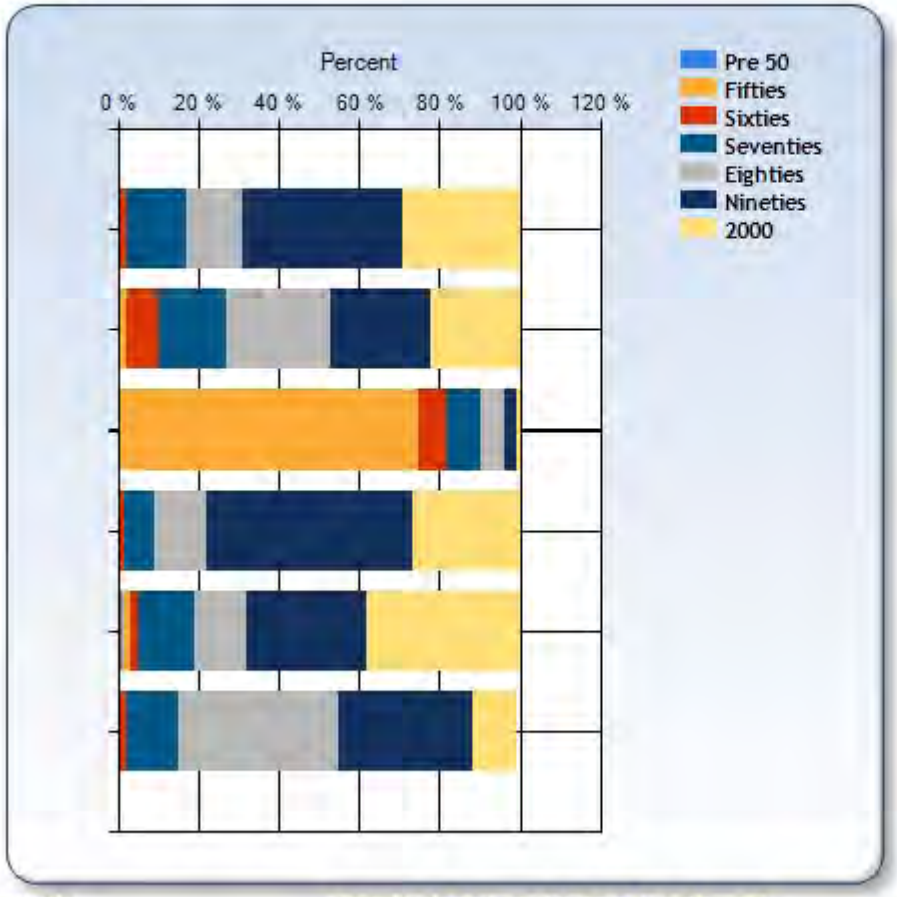
10| PERCENT OF UNDERGROUND CABLE INSTALLED BY DECADE



Comments

Calculation used

Q10.2A, Q10.2B, Q10.3C, Q10.3D, Q10.3E, Q10.3F, Q10.3G

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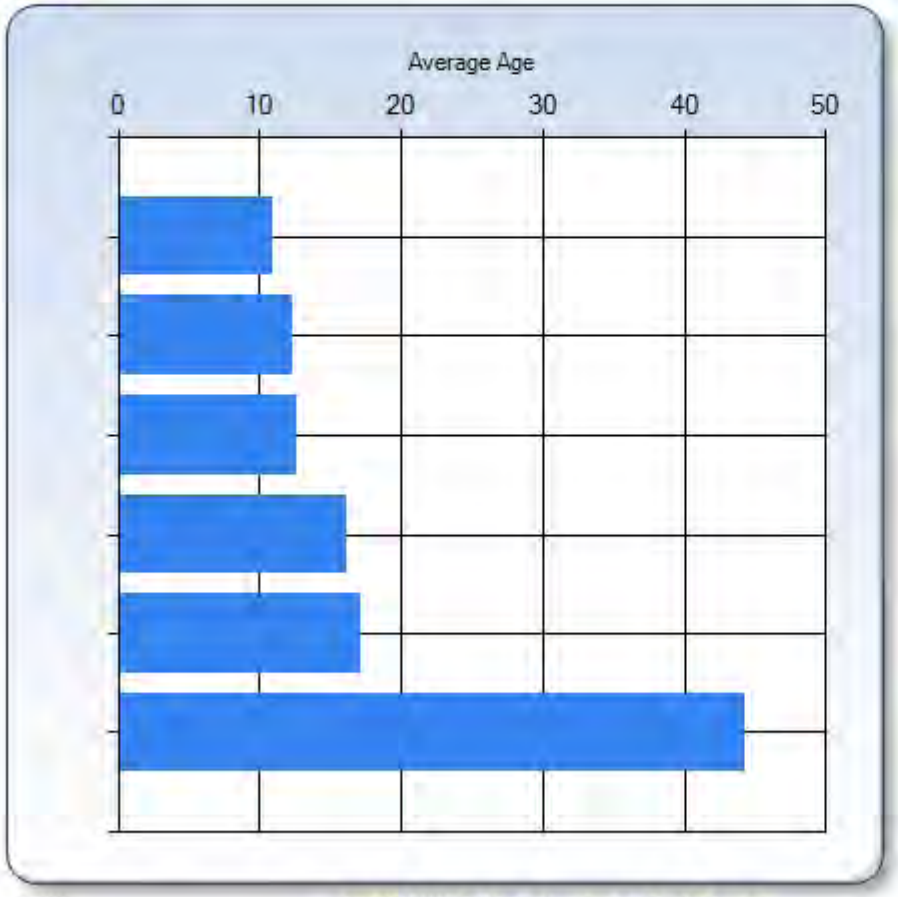
AVERAGE AGE OF COMPONENTS: UG CABLE



Mean Quartile	
Mean	19
Quartile 1	12
Quartile 2:	14
Quartile 3:	17

Comments

Calculation used

(Q10.2A * 60 + Q10.2B * 50 + Q10.3C * 40 + Q10.3D * 30 + Q10.3E * 20 + Q10.3F * 10 + Q10.3G) / 100

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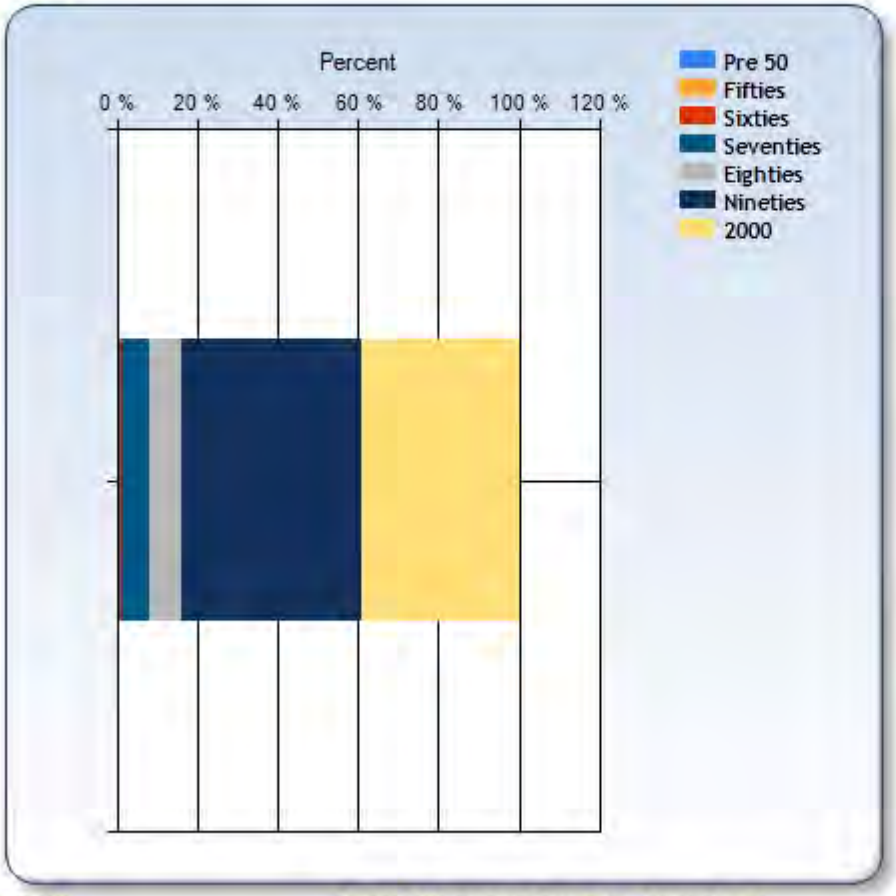
10| PERCENT OF UNDERGROUND SWITCHES INSTALLED BY DECADE



Comments

Calculation used

Q10.4A, Q10.4B, Q10.5C, Q10.5D, Q10.5E, Q10.5F, Q10.5G

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11| HOW DO YOU USE BENCHMARKING DATA TO COMPARE YOUR AGE OF EQUIPMENT TO OTHERS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q11.1

Response
Review periodically and when specific equipment problems arise.
Do not at this time
Benchmarking is used to evaluate restoration durations, reliability, etc...not specific to replace/repair decisions
We do not have enough data on our age of equipment to make any comparison by the use of benchmarking
end of life of equipment
Limited data available to compare
Not used extensively, used for reliability comparison vegetation cycle frequency
No formal benchmarking initiatives have been undertaken

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12| HOW DO YOU MEASURE THE IMPACT OF YOUR REPLACEMENT PROGRAM ON THE AGING INFRASTRUCTURE?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q12.1

Response

Net asset replacement rate & average age of components.

Not measured at this time

No replacement programs

For poles, we just bring up to date our demography estimate using the poles retired and added. Our replacement program is mainly based on a preliminary estimate of poles demography and their failure function. We use the pole as the replacement inductor for the OH sytem. However we do not measure this impact for the undergorund system

reduced failure rates, increase reliability, happy customers

asset turnover level (amount spent on replacements / total cost to replace equipment)

Changes in reliability and specific equipment class failures

Replacement is limited, the impact to service reliability indices is estimated when applicable

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13| DO YOU SET DIFFERENT REPLACEMENT RATES FOR DIFFERENT CRITICAL COMPONENTS OR GEOGRAPHICAL AREAS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q13.1

Response

Assets replacement rates for various components are uniform across the service territory & identified in the strategic plan.

NO

We set a global rate for poles only. That rate was used to establish the global level of investments in equipment replacement

we don't do blanket replacements, we replace components that fail conditionally from inspection programs. .

no

Yes

Replacement is done on a component basis on failure

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14| WHAT ARE THE FACTORS THAT DRIVE DIFFERENT REPLACEMENT RATES?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q14.1

Response

Available funding.

Previous years budget & actual expenditures. Failure trends. Defective equipment found w hen outages occur or as crew executing routine service order.

Overhead: degradation by poles inspection and obsolete equipments Underground: aging, degradation and as found conditions. Obsolete equipements

service conditions, geography, available funding

failure / fault rates

Reliability/Budget/customer issues/w eather

Current performance (failure), replacement cost, impact of failure, and financial constraints

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15| DO YOU CALCULATE THE 'COST OF A SAIDI MINUTE' WITH REGARD TO ELIMINATING A SAIDI MINUTE? IS THIS A USEFUL BENCHMARK IN SUPPORTING INTERNAL INVESTMENT DECISIONS?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q15.1

Response
No, do not use.
Yes,per circuit basis. Yes, useful in the future.
This would be/is very beneficial tool;currently used primarily to help with making budgeting decisions for tree trimming or worst circuit hardening
We calculate the cost of a SADI minute. We also first figured the cost of eliminating a SAIDI minute for the Distribution Automation program and then use that criteria to rank other projects or programs. However decison can also be based on other factors than cost
yes - we measure actual performance improvements in the year after a reliability performance project is completed
No
Not done

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16| WHAT IS THE ROLE OF THE ASSET MANAGEMENT ORGANIZATION IN YOUR DECISION-MAKING?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q16.1

Response

Prioritize & manage entire portfolio of capacity, reliability, and inspection/maintenance programs to achieve budget & customer satisfaction objectives.

NA

Responsible for overall capital budget plan; prioritization of projects; consults on repair/replace decisions and material standards

To set Investment level, Maintenance strategies, Long term and near term Asset Plan To recommand reliability targets and investment strategies at the regulator and Asset owner level

service conditions, geography, available funding

Establishes funding levels for replacements

Asset management drives all the programs setting up and awarding the business plan

Discretionary capital projects are reviewed and analyzed by strategic investment, engineering, & critical property units risk management committees to ensure that any available funds are directed to highest value projects.

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17| WHAT KEEPS YOU UP AT NIGHT WORRYING ABOUT YOUR SYSTEM?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q17.1

Response

All about the same for all components in the entire system.

Failure of key system component that result in frequent or widespread outages (examples: URD cable, poles). Keeping necessary skill sets as experienced personnel retire. Cutting cost to save money in the short term causing larger expenses and equipment failure long term.

Storms

That the lack of data on the age and condition of our distribution sytem components does not enable us to establish the appropriate renewal rate in the long run

aging equipment and low ongoing replacement effort

Safety risks such as aging submarine cable and defective equipments

Our system and industry-wide escalation of equipment failures due to non-proactive replacement and price increases for materials and labor.

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18| REPLACEMENT PROGRAMS UNDERWAY CAPACITORS

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q18.5

Response
Reactive only
Reactive
No program
no replacement program just maintenance program w hich is annual visual inspection, change oil every 5 years or 3000 operations
failure only
No proactive replacement plan budgeted

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18| REPLACEMENT PROGRAMS UNDERWAY OVERHEAD FEEDERS

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q18.4

Response
Being replaced as part of voltage conversion and facility relocation projects
Reactive only
Reactive
Certain types of insulators, cutouts, switches
no program
primarily based on capacity issues
Small & Large Betterment programs
No proactive replacement plan budgeted

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18| REPLACEMENT PROGRAMS UNDERWAY POLES

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q18.1

Response

Pole plant is being replaced as part of voltage conversion and facility relocation projects; also replacing poles found to be defective during annual inspection program

Ground line inspection / treatment

Reactive

No program

test and treat programs, detailed condition assessment for crossarms, pole tops and upper pole body.

yes - based on test results

Pole Replacement Program

Worst condition poles are budgeted for replacement

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18| REPLACEMENT PROGRAMS UNDERWAY TRANSFORMERS

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q18.2

Response
Reactive only
Reactive
No program
run to failure
failure only
PCB Contamination Replacement
No proactive replacement plan budgeted

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18| REPLACEMENT PROGRAMS UNDERWAY UNDERGROUND FEEDERS

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q18.3

Response
Started formal underground cable replacement program in 2008
Reactive only
Reactive
PILC cables replacement program
systematic repalcement program based on its condition.
cable replacement based on fault rates
Submarine Cable Replacement Program
No proactive replacement plan budgeted

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18| REPLACEMENT PROGRAMS UNDERWAY UNDERGROUND SWITCHES

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q18.6

Response
Limited -- older units found to be defective in inspection program
Reactive only
Reactive
Without visible break and mechanical requirements
no replacement program , just maintenance every five years
limited
N/A
No proactive replacement plan budgeted

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19| WHAT ARE THE CLASSES OF EQUIPMENT THAT ARE BECOMING PROBLEMATIC?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q19.1

Response
4 & 8KV equipment installed in the 1950s and 1960s.
Pole top switches
Increasing defective pole inventory
PILC cables and some types of cable joints and splices
cables and accessories
underground cable, crossarms / insulator failures
Poles/ Insulators/ Submarine cables
Primarily distribution cable and wood poles

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21| WHAT IS THE NEXT CLASS OF ASSETS THAT NEEDS TO BE REPLACED [E.G. OLD STYLE UG CABLE? CERTAIN PLASTIC MATERIALS]?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q21.1

Response
UG cable installed in the 1970s & early 1980s. - (started program in 2008)
Non-strand filled URD
Direct Buried cable
Electronic control and a specifical type of cupper cable in overhead and a specifical PILC cable in undergroud
switches
Certain types of wood poles/small conductors/underground cables in the longer term
Primarily wood poles and underground cable

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23| WHAT ANALYTIC APPROACHES DO YOU USE TO PREDICT REPLACEMENT NEEDS?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q23.7

Response

Age, quantity & historical performance of equipment.

Previous years budget and current failure trends.

Cable failure rates; looking at using pole loading and analytical data for pole replacement decisions

For poles we use a predictive approach (top down) based on age distribution profile and failure function. For the other classes we use a bottom up approach based on condition assessment (visual inspections, reliability analysis, pole inspection, customer complaints etc)

we are working on Asset health index, for some components where we know failure rates and age, we use weibull.

using actual failure rates to forecast future failure using probability analysis - least squares fit analysis

Age profile analysis,failure relationships

Trended historical expenditures

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24| HOW ARE THE DECISION CRITERIA FOR REPAIR VERSUS REPLACE DETERMINED?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q24.8

Response

Available funding and short and long-term impacts of proposed solutions.

Costs vs. benefit

Condition, age, failure history- we do not have a repair/replacement decision model

Model is in development to optimize repair and replace criteria. This model will be based on monte carlo simulation, weibull analysis and life cycle costing.

if repair /replace> 1 or life cycle analysis

cost of repair

Based on repairability (Time and $) and the criticality of the feeder

Evaluated on a case-by-case basis; primarily when repair cost exceeds replacement

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25| HOW HAVE YOU USED THE CONCEPTS EMBODIED IN 'RELIABILITY CENTERED MAINTENANCE'?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q25.9

Response

Applied to substation equipment and foresty programs.

No

Substation

We are integrating the risk management through criticality analysis

alw ays

yes - focus maintenance activities on poor reliability areas.

We focus many of our maintenance programs on the reliability data. Distribution feeders w ith high outage incidence w ill get priority over other feeders w here few er outages occur. We have an infra-red line patrol program w hich focuses on feeders w ith poor reliability. Our forestry maintenance programs focus on feeders w ith high incidence of tree caused outages. We have an insulator w ashing maintenance program w hich attempts to prevent flashover outages. All our equipment maintenance programs attempt to correct problems before they cause reliability issues.

NA

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Intelligent Grid - Dist

Intelligent Grid Self Assessment: Distribution

1| Utility's definition of the intelligent grid

2| What technologies are included under the umbrella of intelligent grid?

3| Describe any intelligent grid initiatives underway at your company?

4| Describe any pilots that have been deployed?

5| Describe any wide-scale implementations underway?

6| Top 5 technologies working on deployed for Distribution: Tech 1

6| Top 5 technologies working on deployed for Distribution: Tech 2

6| Top 5 technologies working on deployed for Distribution: Tech 3

6| Top 5 technologies working on deployed for Distribution: Tech 4

6| Top 5 technologies working on deployed for Distribution: Tech 5

7| Customers affected by these implementations

8| Please describe the goals of your Intelligent Grid effort

9| Please check off the areas where you expect benefits.

10| What intelligent grid efforts are you considering?

11| What are the drivers for these efforts?

12| How are these efforts going to be funded?

13| What benefits are you seeing from deployment?

14| Please describe benefits achieved in each of the following: Demand reduction

14| Please describe benefits achieved in each of the following: Duration of interruptions

14| Please describe benefits achieved in each of the following: Energy losses

14| Please describe benefits achieved in each of the following: Frequency of interruptions

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15| Describe how the intelligent grid fits in with other demand response initiatives you have underway

16| Percent C/I load is interruptible today?

17| Percent residential load interruptible today

18| What rates support interruptible loads?

19| Do you currently have time of use rates?

20| How will Intelligent grid improve demand response?

21| Standby generation on system [MW]

22| What programs are underway to dispatch customer-owned resources?

23| How will intelligent grid impact distributed generation?

24| Distribution circuits capable of being remotely operated

25| Switches outside the substation remotely operable

26| Capacitor banks remotely operated

27| What is your long-term goal for AMI penetration?

28| How will intelligent grid impact distribution automation initiatives?

29| Customers with two-way AMI

30| How will intelligent grid impact AMI initiatives?

31| How will AMI support intelligent grid?

32| Please describe any distributed storage initiatives underway?

33| How will intelligent grid impact distributed storage?

34| Intelligent grid spending per customer

35| Please describe any dynamic islanding initiatives underway [e.g. strategies to minimize customer outages by using customer-owned generation?]

36| What barriers did you have to overcome: changes in rates? Prioritization of critical loads?

37| Is there a risk of over-promising the role of outage reduction?

38| How is responsibility for intelligent grid initiatives organized?

39| What problems have you seen in deploying advanced communication into organizations?

40| Have employees been resistant to the change caused by the establishment of the intelligent grid?

41| When do you think there will be a Smart Grid in North America?

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42] Major issues impeding better transmission and distribution in North America today [1 = lowest, 9 = highest]

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INTELLIGENT GRID SELF ASSESSMENT: DISTRIBUTION

Total Respondents	10
A| Our company has a working definition of what an	90%
B| We have identified the technologies included in	80%
C| We have deployed some of the intelligent grid t	80%
D| We have developed the goals for investment in t	50%
E| We have concrete and budgeted plans for additio	40%
F| We are seeing benefits from our deployments. (P	50%
G| We have identified how intelligent Grid fits in	60%
H| We invest a significant amount of money on inte	60%
I| We have focused organizational responsibility f	30%
J| We have identified the technical barriers to im	50%
K| We have identified the financial and regulatory	40%

Comments

Calculation used

Q.1A, Q.1A, Q.1A, Q.1A, Q.1A, Q.1A, Q.1A, Q.1A, Q.1A, Q.1A, Q.1A

Legends										
A| Our company has a working definition of what an	♦	♦	♦	♦		♦	♦	♦	♦	♦
B| We have identified the technologies included in	♦	♦	♦	♦		♦		♦	♦	♦

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C] We have deployed some of the intelligent grid t	♦	♦		♦	♦	♦	♦	♦	♦	
D] We have developed the goals for investment in t		♦		♦		♦		♦	♦	
E] We have concrete and budgeted plans for additio	♦	♦				♦			♦	
F] We are seeing benefits from our deployments. (P		♦			♦	♦	♦	♦		
G] We have identified how intelligent Grid fits in	♦	♦		♦		♦	♦		♦	
H] We invest a significant amount of money on inte		♦		♦		♦	♦	♦	♦	
I] We have focused organizational responsibility f	♦					♦			♦	
J] We have identified the technical barriers to im	♦	♦				♦		♦	♦	
K] We have identified the financial and regulatory		♦				♦		♦	♦	

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1| UTILITY'S DEFINITION OF THE INTELLIGENT GRID

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q1.1

Response

The intelligent grid is a transformed transmission & distribution system that uses robust two-way communications, advanced sensors, and distributed computers to improve the efficiency, reliability and safety of power delivery & use.

To transform the operation of our distribution and substations electric power grid by creating a networked infrastructure capable of delivering and receiving information from intelligent devices distributed across our power system, automating components of the distribution system and leveraging the network for improved operational efficiencies and improved customer satisfaction.

Smart Grid is a portfolio of technologies designed to provide operational, financial and environmental benefits by integrating modern energy and information technologies with electrical power delivery, generation and consumer electrical systems.

A set of applications based on business drivers using modern technologies to improve the distribution system performance (Reliability, Quality, Cost)

A modern, intelligent electricity transmission and distribution system that incorporates elements of traditional and advanced power engineering, sophisticated sensing and monitoring technology, information technology, and communications to provide better

The installation of intelligent devices broadly across the electric delivery system that enables continuing enhancements in the operation, reliability, adaptability, flexibility, utilization, planning, and design of the electrical grid. Enabling Smart Grid technologies also include ubiquitous and high speed communication networks, as well as the 'black office' IT systems that support integration of data from these various intellignet devices, leading to actionable information.

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A communication grid that will allow control and information capture from smart devices on an electrical system. Grid can be extended to customers allowing two way information exchange from customer to utility.

T&D System integrated with a telecommication system and computer technology to improve the performance of the T&D grid

An intelligent distribution system grid consists of automated devices that isolate system disturbances, insure system voltage stability, and control customer loading.

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2| WHAT TECHNOLOGIES ARE INCLUDED UNDER THE UMBRELLA OF INTELLIGENT GRID?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q2.1

Response

Distr. automation, distributed generation (DG) integration, DMS, EMS, substation (SS) integration, home area network, micro-grids, SS protection, Meter Data Mgt., Two-way communication networks (RF, Cellular, WiFi), DSM (AIC), GIS, OMS.

To design, install, operate and maintain deployed intelligent devices across our substations and distribution system which will monitor, protect and automate the grid. This will be combined with a communication system linking the intelligent devices in a networked fashion creating opportunities for optimizing system performance and providing information to the electric market. (REPs/Regulators/Customers)

AMI, Distribution Automation (DA), Substation Automation (SA)

Remote controlling of distribution switches and breakers leading to automatic configuration, Volt and Var control, Accurate fault location based on waveshape analysis. Proposal on drive by AMR system under approbation Demand response, distributed generation including micro-grid are far on our horizon.

Smart meters and infrastructure, Distribution Automation, Volt-VAR Optimization, Home Area Network, Microgrids, Distributed Generation Integration, Energy Storage, Distribution Management System

DMS/OMS, Dist automation, AMS, BPL, substation automation, Advanced Meter Infrastructure.

Distribution automation, demand side management capabilities at customer loads, fault location, remote connect/disconnect of customers, load shedding, automatic connectivity ability, knowledge of customer outage status

Telecommunications, advanced P&C, Centralized Control, Substation Automation, Distributed Monitoring and Control, Environmental Management System(EMS)/Defect Management System(DMS)/Supervisory Control and Data Acquisition(SCADA)

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3| DESCRIBE ANY INTELLIGENT GRID INITIATIVES UNDERWAY AT YOUR COMPANY?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q3.1

Response

AMI, DMS, EMS, Mobile Data

AMI, smart roll, TLM, Substation automation, fault location, fault characterization

AMI Pilot, evalutaion of the potential Distribution Automation and Substation Automation Projects

Remote controlling of distribution switches and breakers leading to automatic configuration

see #2

New DMS/OMS/MWMS systems; Substation automation upgrades; Increased installation of 'smart' switches, reclosers, and capacitor controls; AMS program Installation of an Advanced Meter Radio Frequency and Power Line Carrier network for all meters.

Command Sequence Switching on Network Management System(NMS), AMI, Outage Management System(OMS)

Automated group operated disconnect switches and automated capacitor controllers.

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4| DESCRIBE ANY PILOTS THAT HAVE BEEN DEPLOYED?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q4.1

Response

DV 2010 micro grid, 2-way capacitor bank controls, remote FCIs with automatic outage notification.

two substation area, 10K meters deployed, 7 circuit with automated equipment

AMI Pilot based on RF mesh network.

Pilot Projects on Volt and Var control Accurate fault location based on waveshape analysis. Proposal on drive by AMR system under approbation and pilot project on AMI to be implemented in 2009 (3 sites)

smart meters

AMS. Starting on April 28, 2008, a 5000 meter pilot begain using a radio frequency mesh network.

WI-MAX Pilot(high bandwidth microwave based wireless telecommunication), Remote Switching pilot

Automated group operated disconnect switches, air conditioner controllers, and automated capacitor controllers.

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5| DESCRIBE ANY WIDE-SCALE IMPLEMENTATIONS UNDERWAY?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q5.1

Response

AMI, SS integration & SCADA additions

in preparation for larger scale meter deployment, in preparation for communications netw ork design, in developement for smart grid design

Plans for AMI

Ongoing project of remote controlling one third of our distribution system (1000 feeders, 3750 feeder sw itches & breakers) up to 2013

smart meters to be installed for all customers by 2012

Subsation Automation, Distribution automation, BPL. Starting in September 2008, replace all 3.4 million meters by the end of 2012.

AMI, OMS

Automated capacitor controllers and Summer Saver air conditioner controllers

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6| TOP 5 TECHNOLOGIES WORKING ON DEPLOYED FOR DISTRIBUTION: TECH 1

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q6.1

Response
AMI implementation,
DG
AMI
Remote controlling of distribution switches and breakers leading to automatic configuration
Smart Meters & Communications Infrastructure Smart Meters & Communications Infrastructure
DMS/OMS
Distribution automation pilot
AMI
Automated Capacitor controllers

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6| TOP 5 TECHNOLOGIES WORKING ON DEPLOYED FOR DISTRIBUTION: TECH 2

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q6.2

Response
AMI DMS integration,
DA
Distribution Automation/Feeder Automation
Volt and Var control
Distributed Generation Integration
Distribution Automation
Distributed storage pilot (battery)
Distribution automation

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6| TOP 5 TECHNOLOGIES WORKING ON DEPLOYED FOR DISTRIBUTION: TECH 3

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q6.3

Response
DA & SCADA additions,
AMI
Substation Automation/Smart Substation
Accurate fault location based on w aveshape analysis
Distribution Automation (e.g. reclosers, sw itches)
Substation Automation
Summer Saver air conditioning control is probably #1 in quantity and money spent

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6| TOP 5 TECHNOLOGIES WORKING ON DEPLOYED FOR DISTRIBUTION: TECH 4

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q6.4

Response

Dist. SS integration,

DMS

Plug-In Hybrid Vehicles

Proposal on drive by AMR system under approbation

Distribution Management System

Advanced Meter Infrastructure with a Power Line Carrier network

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6| TOP 5 TECHNOLOGIES WORKING ON DEPLOYED FOR DISTRIBUTION: TECH 4

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q6.4

Response
Dist. SS integration,
DMS
Plug-In Hybrid Vehicles
Proposal on drive by AMR system under approbation
Distribution Management System
Advanced Meter Infrastructure with a Power Line Carrier network.

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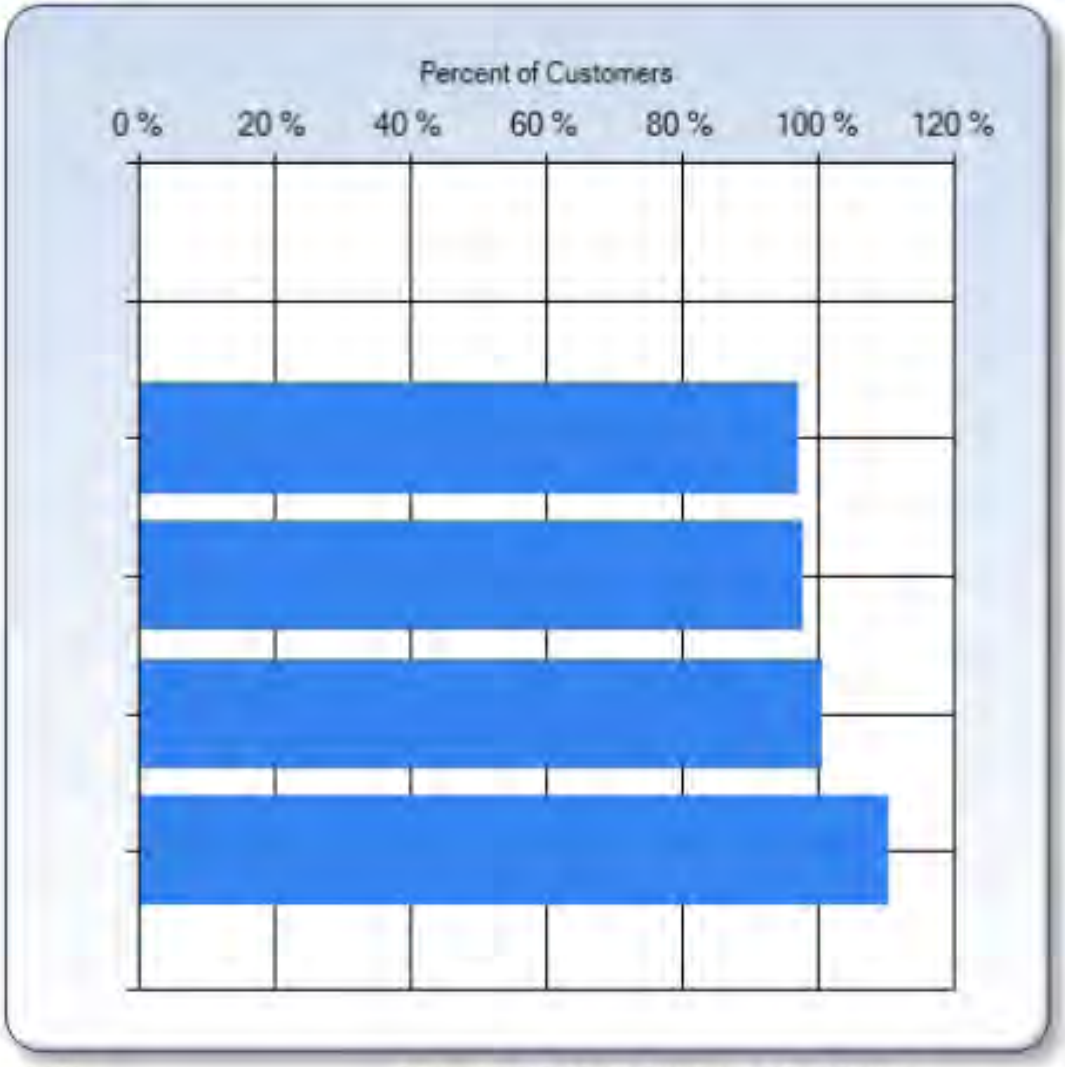
7| CUSTOMERS AFFECTED BY THESE IMPLEMENTATIONS



Mean Quartile	
Mean	81 %
Quartile 1	97 %
Quartile 2:	98 %
Quartile 3:	101 %

Comments

Calculation used

Q7.1 / (T&D Dist End Use Customers) * 100

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8| PLEASE DESCRIBE THE GOALS OF YOUR INTELLIGENT GRID EFFORT

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q8.1

Response

Enhance the capabilities of automated & manual decision support tools to maximize the efficiency of the electric dist. system & provide customers with the knowledge to effectively manage their usage.

Improve reliability and support the dereg market

Improved Customer Service, Improved system reliability, Increase amount and optimize use of system data

Goal are different for each application 1- Remote controlling of 3750 feeder switches & breakers - Improve SAIDI for customers having more thatn 4hrs per year 2- Pilot project on Volt and Var control - Improve energy efficiency by saving up to 2,0 TWh 3- Pilot project on Fault location based on waveshape analysis - Improve SAIDI by pinpointing faults to maintenance crews for preventive maintenance and for system operation. Developping preventive maintenance 4- Proposal on drive by AMR system under approbation - reduce the cost of manpower by automaticaly reading energy meters

see #1

The Goals of AMI: to collect data for use by the Retail Market, to provide products to the end use customer that will help reduce their electric consumption, and to provide data for use in system performance and outage detection and restoration.

Reliability improvements and load reduction during peak hours

Demand Management, Operating Efficiency, Customer Satisfaction

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9| PLEASE CHECK OFF THE AREAS WHERE YOU EXPECT BENEFITS.

Total Respondents	9
Reduce the frequency of customer interruptions	77.78%
Reduce the duration of customer interruptions	88.89%
Reduce customer peak demand	55.56%
Enable enduse energy storage	33.33%
Avoid investment in additional infrastructure	44.44%
Achieve a rate of return on investment	44.44%
Reduce energy losses although most of these are p	88.89%
Reduce CEMx an intelligent grid can use load she	55.56%
Reduce need to spend on core infrastructure.	44.44%
Optimization: Tradeoff w ith core actions like fee	44.44%

Comments

Calculation used

Q9.1, Q9.2, Q9.3, Q9.4, Q9.5, Q9.6, Q9.7, Q9.8, Q9.9, Q9.10

Legends									
Reduce the frequency of customer interruptions	♦	♦	♦		♦		♦	♦	♦
Reduce the duration of customer interruptions	♦	♦	♦		♦	♦	♦	♦	♦
Reduce customer peak demand	♦		♦	♦		♦			♦
Enable enduse energy storage	♦					♦			♦

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Avoid investment in additional infrastructure	♦					♦		♦	♦
Achieve a rate of return on investment					♦	♦		♦	♦
Reduce energy losses although most of these are p	♦	♦		♦	♦	♦	♦	♦	♦
Reduce CEMIx an intelligent grid can use load she	♦					♦	♦	♦	♦
Reduce need to spend on core infrastructure.	♦					♦		♦	♦
Optimization: Tradeoff w ith core actions like fee	♦	♦						♦	♦

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10| WHAT INTELLIGENT GRID EFFORTS ARE YOU CONSIDERING?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q10.1

Response

DMS fault locating, additional SS equipment monitoring.

More sophisticated design, DMS, feeder automation

AMI, DA, SA

Already describes above

see #2

Advanced Meter Infrastructure.

Broad discussions at this time, no plans to implement as yet

DS Monitoring, Integration of AMI & OMS, Integrating Generation Dispatch to match grid capacity, Dx Automation

None

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11| WHAT ARE THE DRIVERS FOR THESE EFFORTS?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q11.1

Response

Reduce CAIDI, prioritize distr system maintenance w ork.

CAPEX, aging infrastructure, aging w orkforce, improved reliability, regulatory market

Improved Customer Service, Improved system reliability, Increase amount and optimize use of system data

Reliability for customers having 4 hrs and more Energy efficiency Cost Efficiency (reduce manpow er cost)

future customer needs and regulatory environment

State Legislation (voluntary), customer satisfaction, reliability inprovements.

Company has had a number of companies giving presentations on the capabilities of smart grids and w hat other companies have achieved or are w orking on.

Demand Management, Operating Efficiency, Customer Satisfaction, maximizing use of existing capacity

None

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12| HOW ARE THESE EFFORTS GOING TO BE FUNDED?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q12.1

Response

Utilize existing staff & approved budget.

various including rate base

TBA

Each of the above applications had been justified piece by piece looking at the global vision. It will be the same for future applications.

individual business cases

Surcharge available when certain requirements are meet.

From Tx and Dx rate bases

None

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13| WHAT BENEFITS ARE YOU SEEING FROM DEPLOYMENT?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q13.1

Response

Increased know ledge to support capital and O&M spend decisions.

meter read accuracy, engineering data from equipment

Improved Customer Service, Improved system reliability, Increase amount and optimize use of system data

Although the remote controlling project is very young w e are starting to see some SAIDI improvement. For other pilot projects benefits are being evaluated within each pilot and results are, so far, promising Reduce cost of doing business in the long run

not yet deployed

System upgrades replace older equipment.

OMS and Command Sequence sw itching, firm customer satisfaction, firm w ork efficiency, improved SAIDI

Thru Summer Saver, seeing reduced peak load w hich results in less generation needs. It also helps defer distribution investment.

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14| PLEASE DESCRIBE BENEFITS ACHIEVED IN EACH OF THE FOLLOWING: DEMAND REDUCTION

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q14.1

Response
45 MW immediate load shed via A/C load control available,
in test
TBD
N/a
none yet
Not tracked and reported

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14| PLEASE DESCRIBE BENEFITS ACHIEVED IN EACH OF THE FOLLOWING: DURATION OF INTERRUPTIONS

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q14.3

Response
CAIDI reductions achieved w ith improved DMS, OMS & SCADA additions,
in test
TBD
Expected 20 % on SAIDI
none yet
None

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14| PLEASE DESCRIBE BENEFITS ACHIEVED IN EACH OF THE FOLLOWING: ENERGY LOSSES

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q14.4

Response
Minimal gains due to cost of conversion
in test
TBD
Not know n yet
none yet
Not tracked and reported

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14| PLEASE DESCRIBE BENEFITS ACHIEVED IN EACH OF THE FOLLOWING: FREQUENCY OF INTERRUPTIONS

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q14.2

Response
Unknown at this time
in test
TBD
Not known yet
none yet. Reliability related to dist automation is being calculaed.
None

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15| DESCRIBE HOW THE INTELLIGENT GRID FITS IN WITH OTHER DEMAND RESPONSE INITIATIVES YOU HAVE UNDERWAY.

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q15.1

Response

Advanced monitoring & models have allow ed dist. planning engineers to evaluate impacts of distributed generation (DG) & load control devices on the SS & feeder basis.

n/a

TBD

n/a

allow s time of use rates and peak shaving

Demand response is not a function of the Transmission Distribution service provider in Texas. We are enabling Demand Response by providing a communications pathw ay for meter data and DR signal from the Retail Electric Provider to their customers.

Could fit in w ith air conditioning control project piloted in SLC and distribution automation pilot.

None

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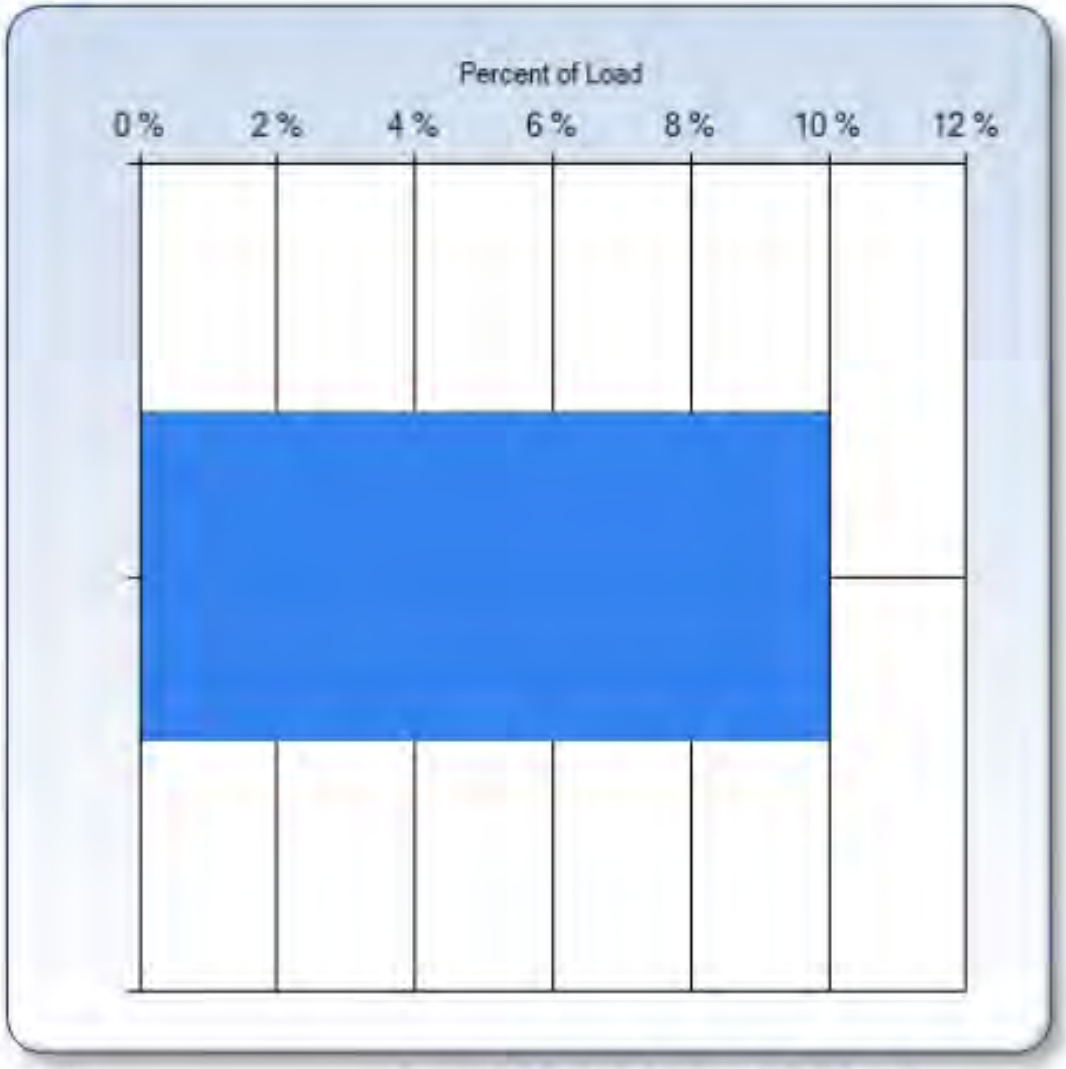
16| PERCENT C/I LOAD IS INTERRUPTIBLE TODAY?



Mean Quartile	
Mean	10 %
Quartile 1	10 %
Quartile 2:	10 %
Quartile 3:	10 %

Comments

Calculation used

Q16.1

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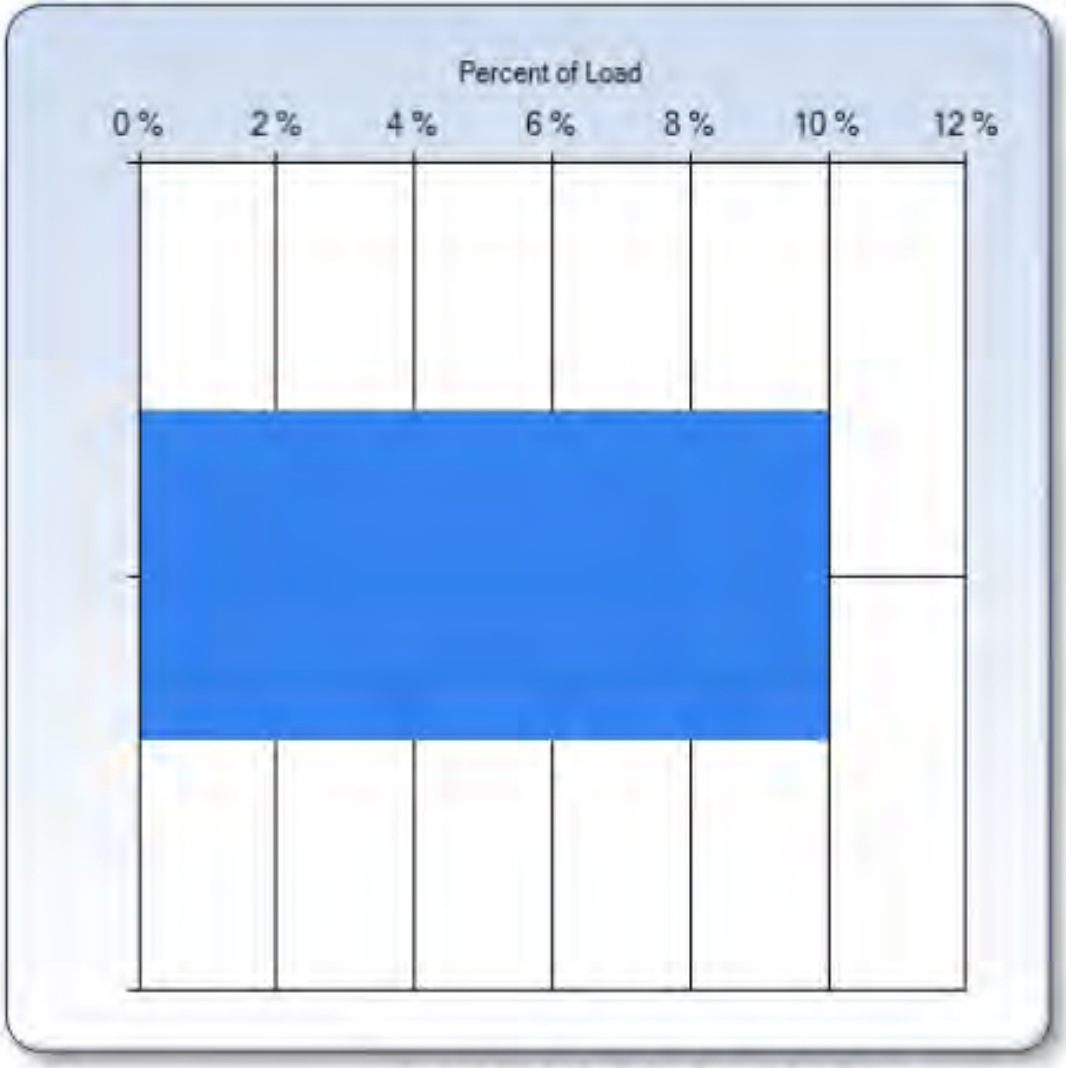
17| PERCENT RESIDENTIAL LOAD INTERRUPTIBLE TODAY



Mean Quartile	
Mean	10 %
Quartile 1	10 %
Quartile 2:	10 %
Quartile 3:	10 %

Comments

Calculation used

Q17.1

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18| WHAT RATES SUPPORT INTERRUPTIBLE LOADS?

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q18.1

Response
Residential, Industrial
n/a
TBD
Frequency Interruptible, Notice interruptible
unavailable

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19| DO YOU CURRENTLY HAVE TIME OF USE RATES?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q19.1

Response
Yes
no
TBD
NO
pilot only
Yes
yes

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20| HOW WILL INTELLIGENT GRID IMPROVE DEMAND RESPONSE?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q20.1

Response

Provide customers with real-time prices of electricity & the ability to control in-house usage.

n/a

TBD

N/A

smart meters will enable demand response

Provide information and a communication pathway for the Retail Electric Provider to the customer.

Improve response, flexibility, and tracking of MW impact

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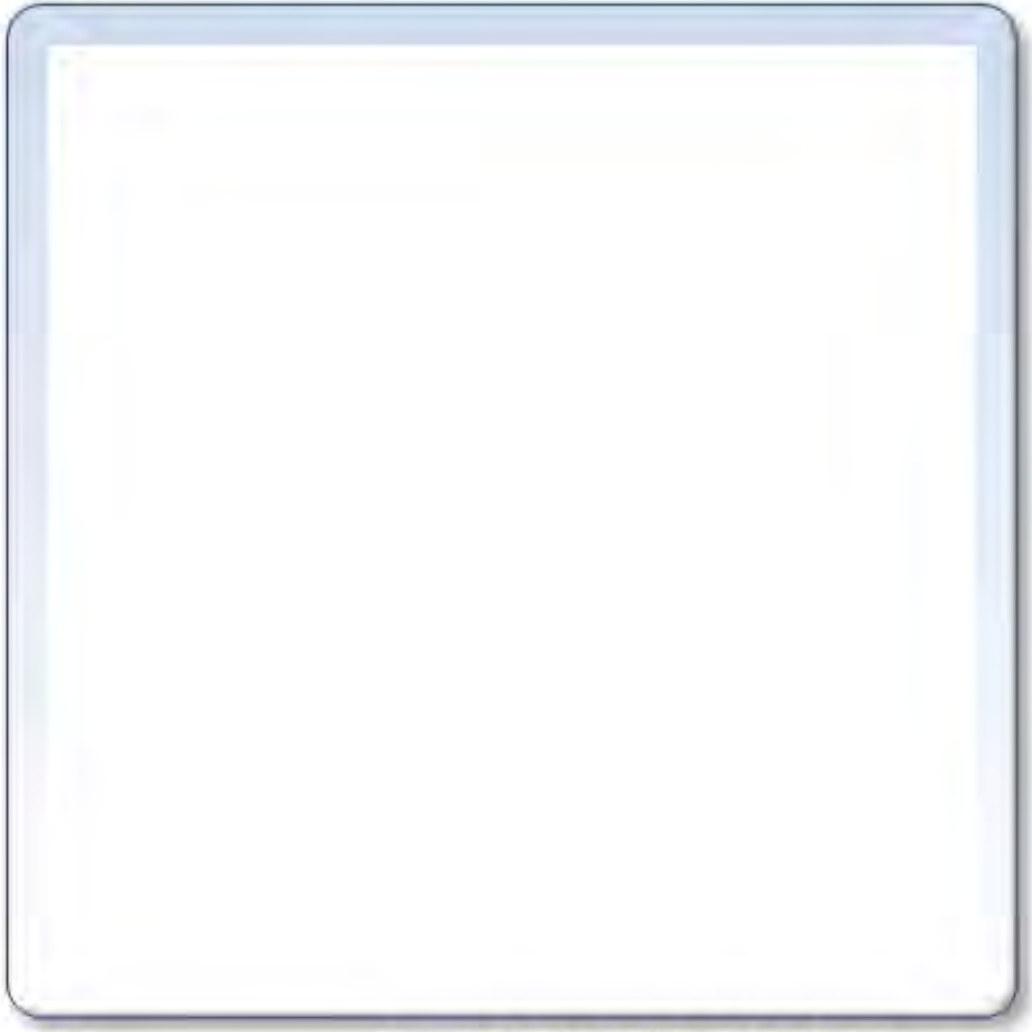
21| STANDBY GENERATION ON SYSTEM [MW]



Mean Quartile	
Mean	Empty
Quartile 1	Empty
Quartile 2:	Empty
Quartile 3:	Empty

Comments

Calculation used

Q21.1

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22| WHAT PROGRAMS ARE UNDERWAY TO DISPATCH CUSTOMER-OWNED RESOURCES?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q22.1

Response

Electric service rules currently in place for small distributed generation (DG) (e.g., wind, solar PV, & landfill).

none at this time due to regulatory market

Part of the Smart Grid Planning

Program available but very few customers are joining it.

Independent Power Producer program; Distribution Management System will support

None

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23| HOW WILL INTELLIGENT GRID IMPACT DISTRIBUTED GENERATION?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q23.1

Response

Advanced metering technology will help enable DG by providing real-time pricing signals & cost information to small generators.

IG will support acceptance of DG, no net

Enable full DG control

Few impact for now due to the energy cost in Quebec

Smart Grid applications will enable distributed generation integration.

Improve response, flexibility, and tracking of MW impact

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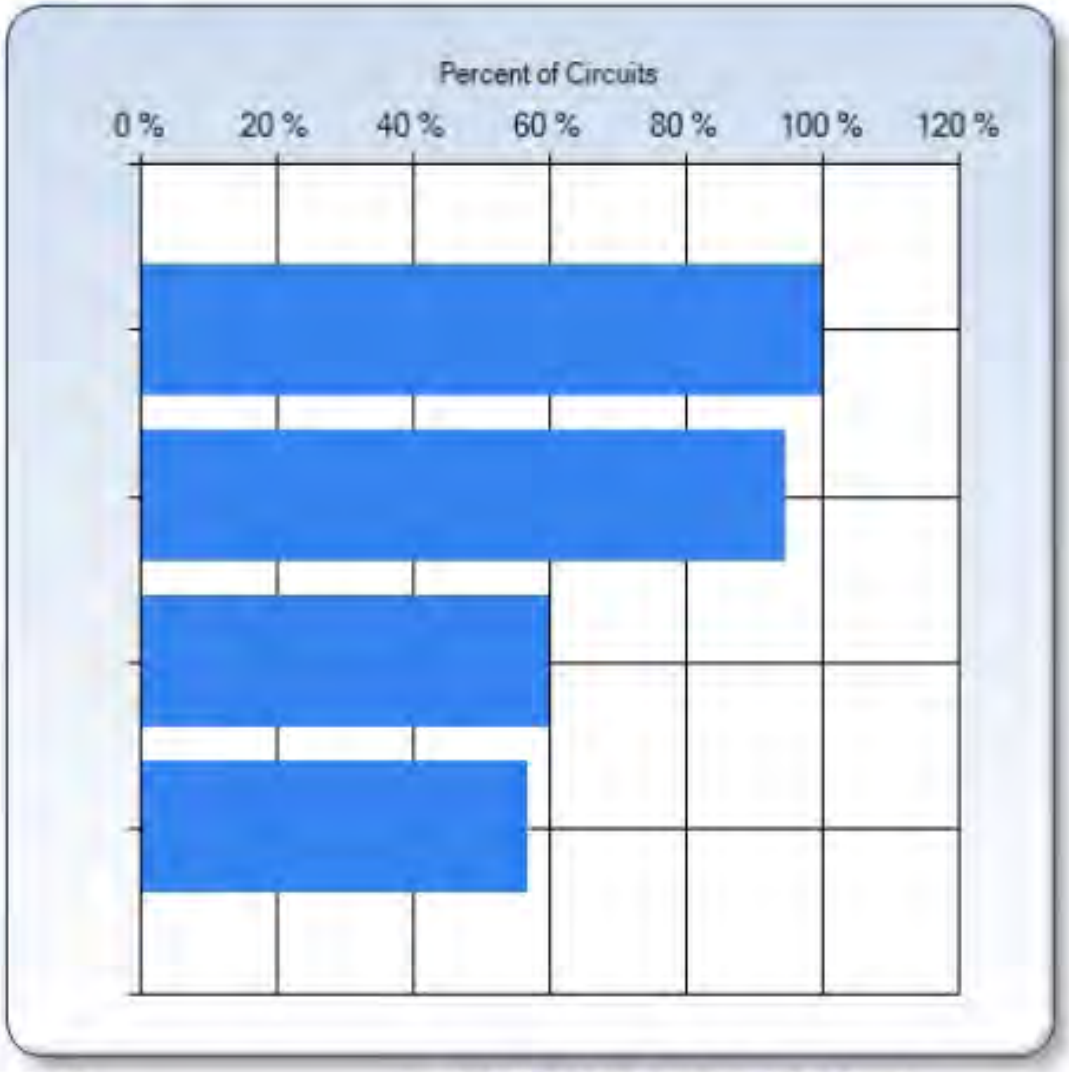
24| DISTRIBUTION CIRCUITS CAPABLE OF BEING REMOTELY OPERATED



Mean Quartile	
Mean	78 %
Quartile 1	96 %
Quartile 2:	78 %
Quartile 3:	59 %

Comments

Calculation used

Q24.1

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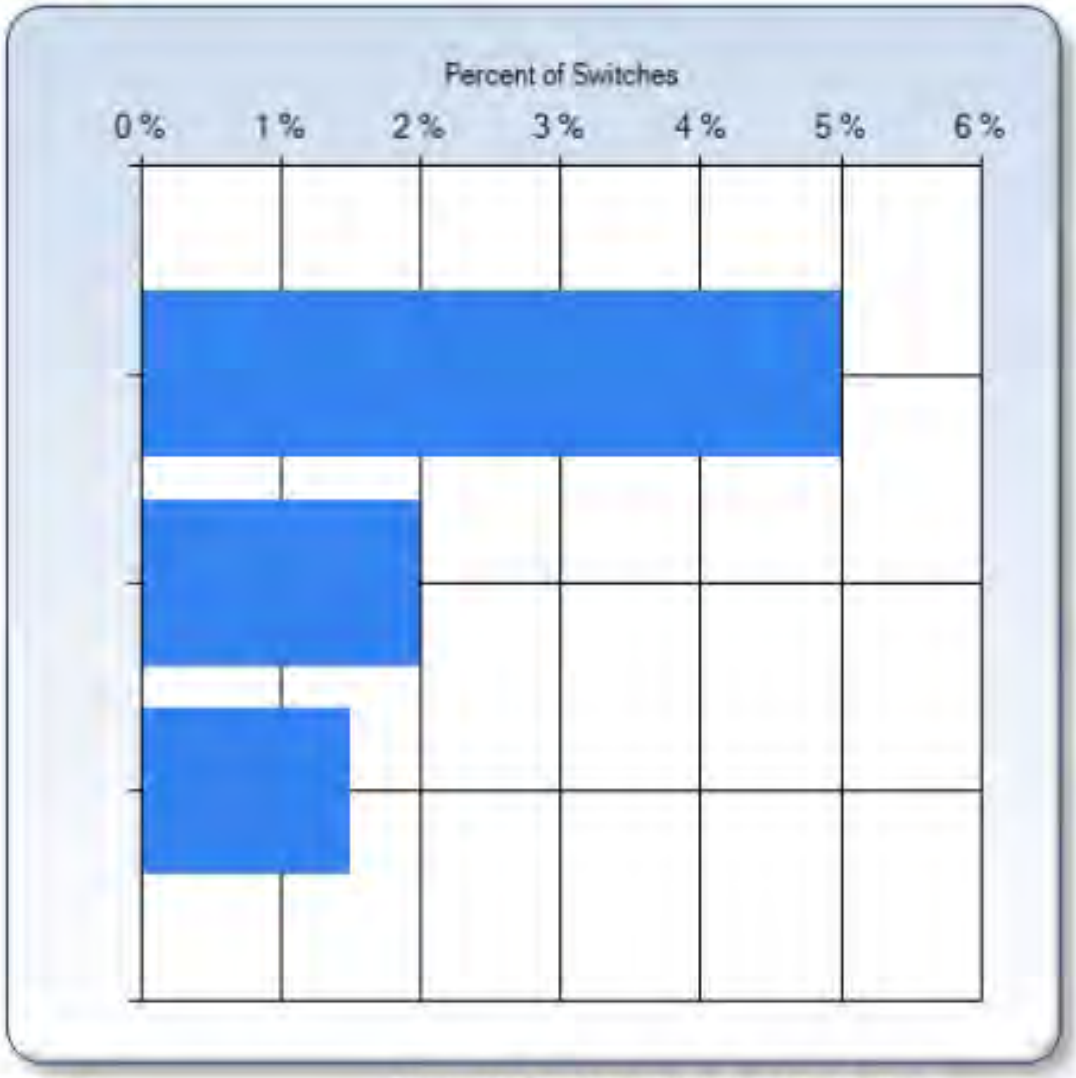
25| SWITCHES OUTSIDE THE SUBSTATION REMOTELY OPERABLE



Mean Quartile	
Mean	3 %
Quartile 1	4 %
Quartile 2:	2 %
Quartile 3:	2 %

Comments

Calculation used

Q25.1

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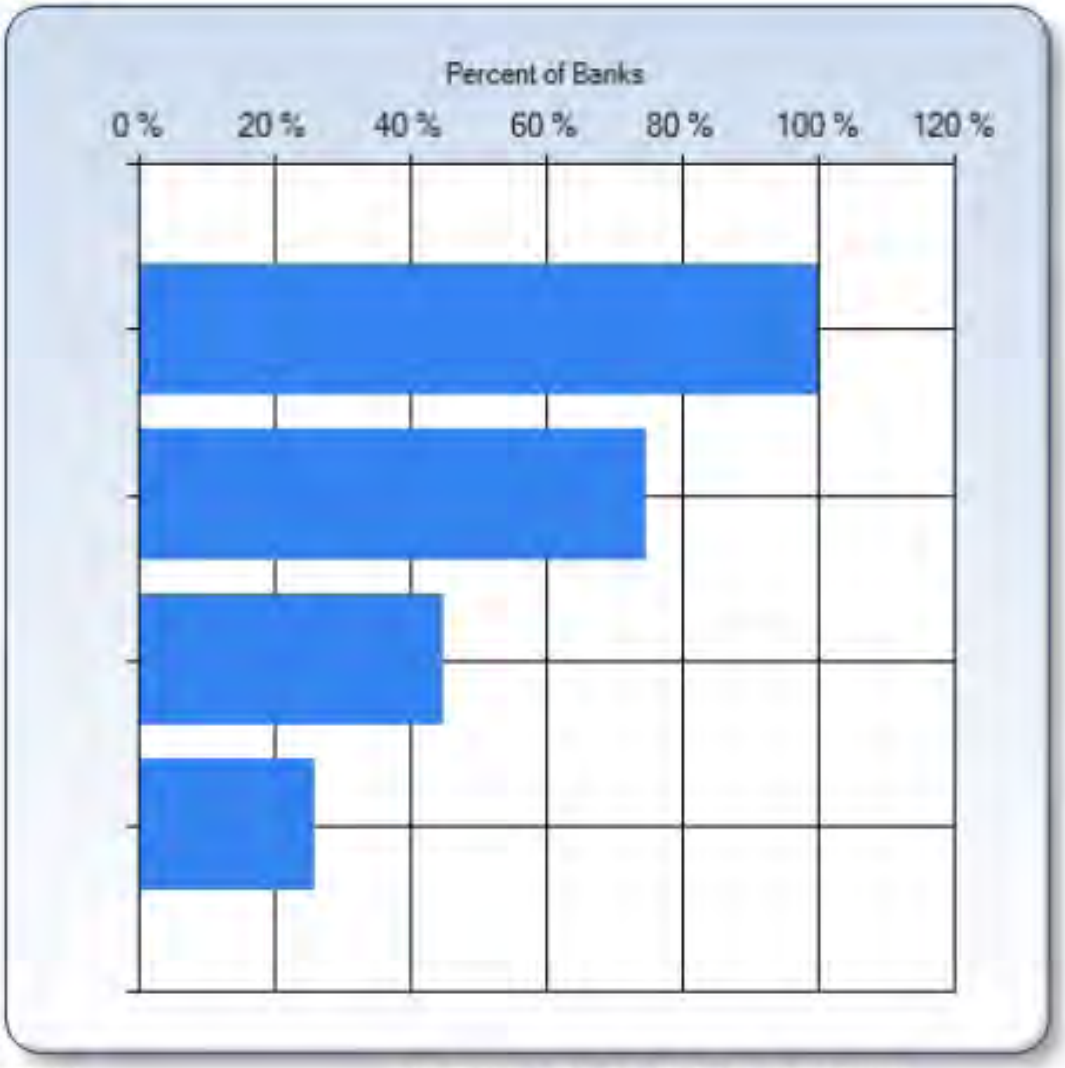
26| CAPACITOR BANKS REMOTELY OPERATED



Mean Quartile	
Mean	62 %
Quartile 1	81 %
Quartile 2:	60 %
Quartile 3:	40 %

Comments

Calculation used

Q26.1

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27| WHAT IS YOUR LONG-TERM GOAL FOR AMI PENETRATION?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q27.1

Response
97
100%
100
100
100
100
0.00

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28| HOW WILL INTELLIGENT GRID IMPACT DISTRIBUTION AUTOMATION INITIATIVES?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q28.1

Response

Provide 2-way communication network for monitoring & control.

design will facilitate further deployment

SG will enable DA on selected feeders

End of remote controlling project 2013, beginning of automatic reconfiguration 2013

support

They are strategically linkes with overview managemnt teams.

It is an enabler

Improve communication to field devices, system response time, flexibility of options.

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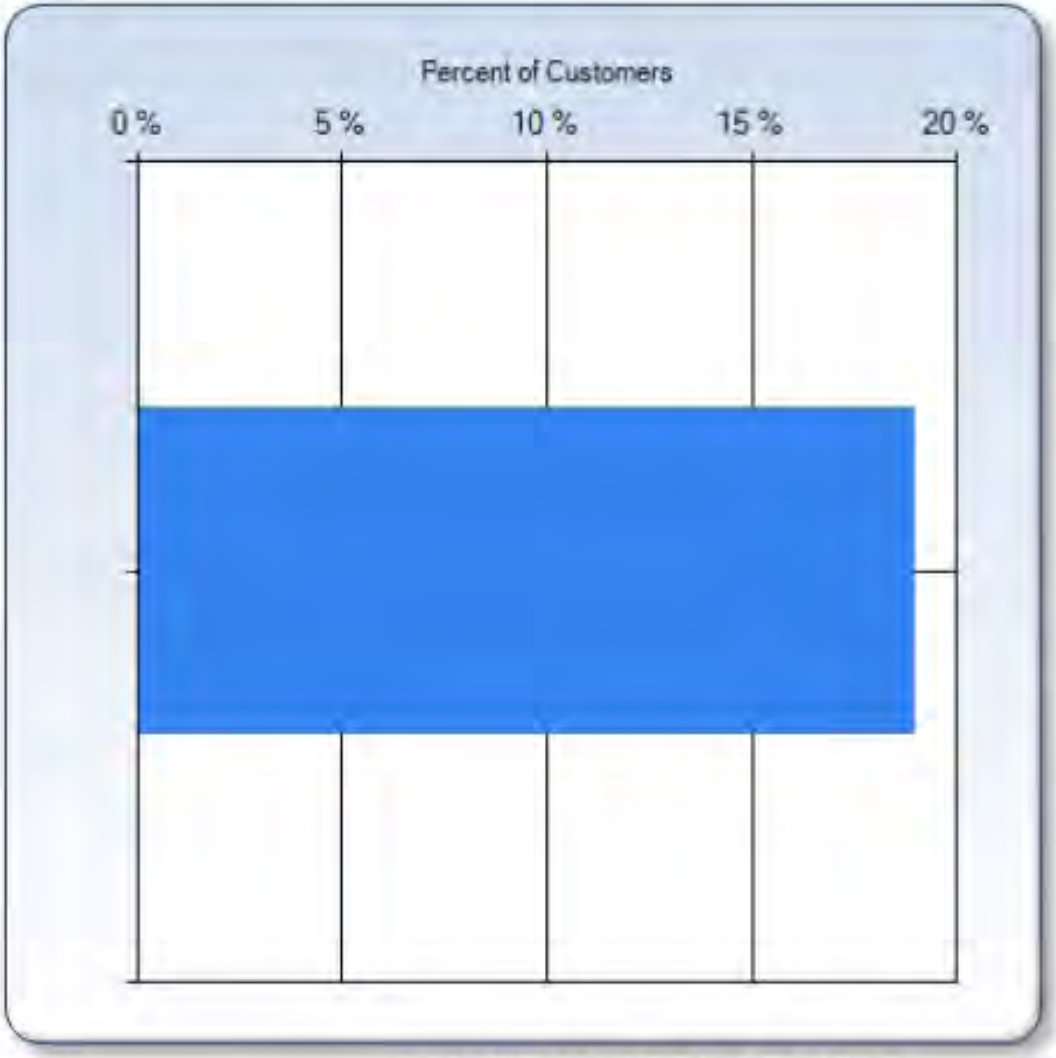
29| CUSTOMERS WITH TWO-WAY AMI



Mean Quartile	
Mean	19 %
Quartile 1	19 %
Quartile 2:	19 %
Quartile 3:	19 %

Comments

Calculation used

Q29.1

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30| HOW WILL INTELLIGENT GRID IMPACT AMI INITIATIVES?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q30.1

Response

May drive schedule in order to obtain system data or control loads.

Consideration of IG in AMI design helps establish meter functionality and performance requirements,as well as, back office and communication infrastructure design for moving metered data supporting IG to IG systems.

AMI is integral part of SG initiative

Although AMI is implemented in several Distribution utilities, HQ roadmap does not justify it before 2018

DMS will liaise with meters to control customer loads

None

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31| HOW WILL AMI SUPPORT INTELLIGENT GRID?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q31.1

Response

Data source and communication path (2-way AMI)

AMI can support IG with outage/restoration notification, voltage, voltage alerts, fault detection inputs, and meter to phase relationships.

AMI is integral part of SG system

AMI meters can add valuable information for operation and maintenance of the distribution system

AMI will provide a communications network to support Smart Grid

Provide outage and restoration information, voltae sags and swells, outage duration

None

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32| PLEASE DESCRIBE ANY DISTRIBUTED STORAGE INITIATIVES UNDERWAY?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q32.1

Response
n/a
TBD
Some acitivies on R&D Benchmark and surveys
Vanadium redox battery in Moab Utah - pilot in place for over 4 years
None
None

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33| HOW WILL INTELLIGENT GRID IMPACT DISTRIBUTED STORAGE?

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q33.1

Response
n/a
Enable full DS control
Far on our horizon
see #30
Probably w on't - in rural area that w ould most likely not have intelligent grid implemented
N/A
None

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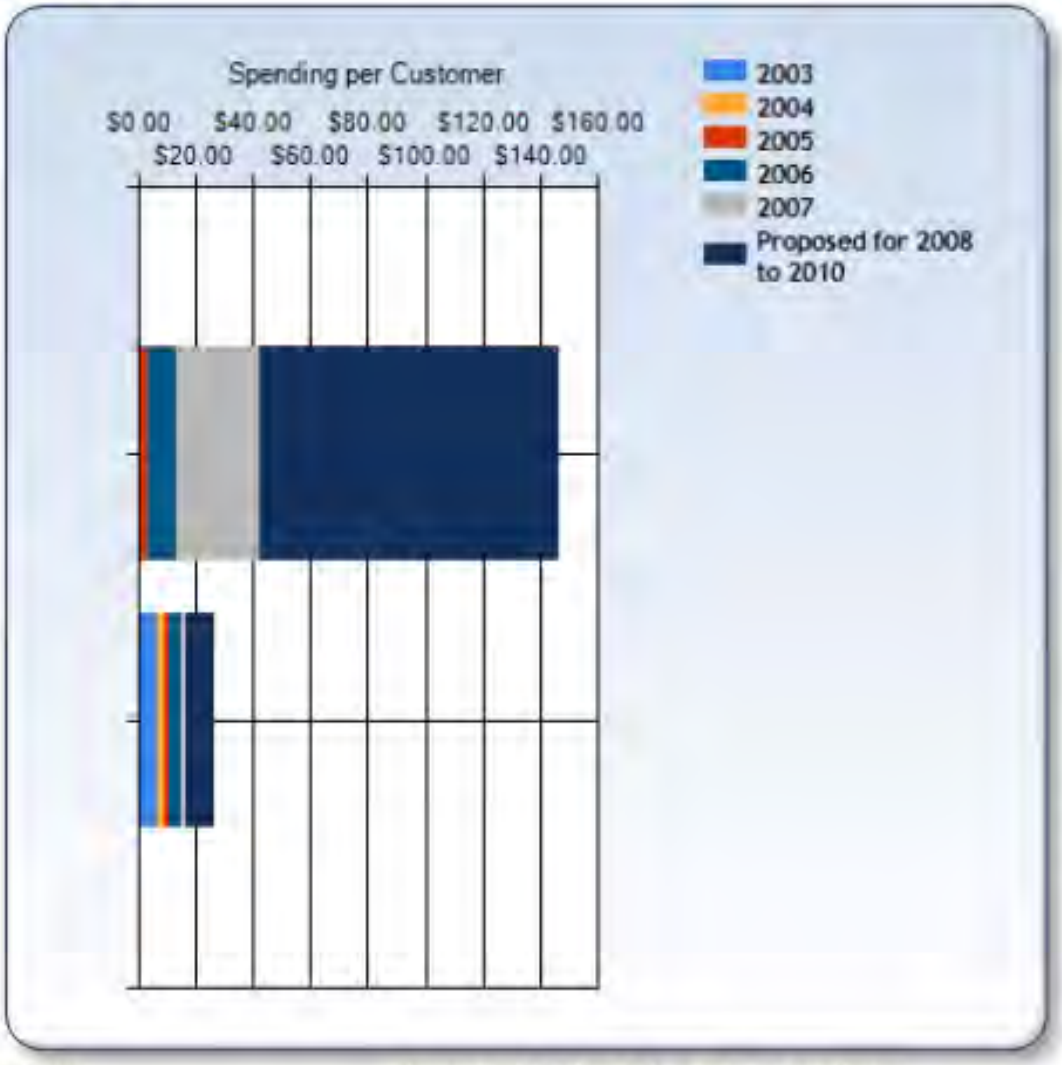
34| INTELLIGENT GRID SPENDING PER CUSTOMER



Mean Quartile	
Mean	$86.51
Quartile 1	$116.36
Quartile 2:	$86.51
Quartile 3:	$56.67

Comments

Calculation used

Q34.1 / (T&D Dist End Use Customers), Q34.2 / (T&D Dist End Use Customers), Q34.3 / (T&D Dist End Use Customers), Q34.4 / (T&D Dist End Use Customers), Q34.5 / (T&D Dist End Use Customers), Q34.6 / (T&D Dist End Use Customers)

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35| PLEASE DESCRIBE ANY DYNAMIC ISLANDING INITIATIVES UNDERWAY [E.G. STRATEGIES TO MINIMIZE CUSTOMER OUTAGES BY USING CUSTOMER-OWNED GENERATION?]

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q35.1

Response
None
n/a
TBD
1 R&D project (Senneterre) in 2003
see #30
Considered it with Vanadium battery but funding never was established
none
none

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36| WHAT BARRIERS DID YOU HAVE TO OVERCOME: CHANGES IN RATES? PRIORITIZATION OF CRITICAL LOADS?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q36.1

Response
Not applicable
n/a
TBD
Project did not reach this point
None
none

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37| IS THERE A RISK OF OVER-PROMISING THE ROLE OF OUTAGE REDUCTION?

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q37.1

Response

Not applicable

n/a

TBD

Existing Dispersed generation standards leave the door open for DER to generate during outages, but it was never asked nor used.

Yes

none

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38| HOW IS RESPONSIBILITY FOR INTELLIGENT GRID INITIATIVES ORGANIZED?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q38.1

Response

Presently distributed throughout organization

matrix

TBD

Each application is developped under two steering committees involving Operation, Asset management and Maintenance directions

Smart Grid Program team directs overall development; individual applications led by appropriate departments.

CIO in charge of Technology Team; Manager involved with Dist auto and substation auto informd or AMS and OMS/Dms programs.

Currently discussions are originating only at president and vice president level

AMI management structure, other initiatives are project based (usual processes)

none

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39| WHAT PROBLEMS HAVE YOU SEEN IN DEPLOYING ADVANCED COMMUNICATION INTO ORGANIZATIONS?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q39.1

Response

Significant cost & lack of long term commitment to communications protocols by vendor.

communications technology not ready for full deployment, cost

TBD

Gathering the needs for broadly dispersed distribution system covering all kind of networks and having several hurdles (geographical, several telcommunications technologies...)

Rapidly evolving technology, security issues, and lack of standards.

Training for operation/trouble shooting. Future organizational issue.

From past project experience, always the concern with reliability and security

Telecom cost major factor for large, geographic, rural utility

none

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40| HAVE EMPLOYEES BEEN RESISTANT TO THE CHANGE CAUSED BY THE ESTABLISHMENT OF THE INTELLIGENT GRID?

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q40.1

Response

No, the concepts related to the intelligent grid (IG) have been under development for some time.

somew hat

TBD

Negligeable but communication plans are required

Change management and organizational development w ll be key to success.

No

Not so much the change as the allocation of resources, concern w hether smart grid is the best place to spend funds

It's here, the question is the extent to w hich..

none

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41| WHEN DO YOU THINK THERE WILL BE A SMART GRID IN NORTH AMERICA?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q41.1

Response

Already here in some areas. Future deployment should be value driven by the customer & distribution system needed to most effectively serve customer load.

2020

2018 at 50% of utilities

Depending of the definition of smart grid and considering that the life expectancy of the distribution system can be 40 years, it can take 20 years to have 50 % of the system covered by some smart Grid applications

Smart Grid is an evolution.

After discussions with others in the utility industry, I believe a number of companies are nearing a implementation pilot or are studying AMI with the intention to move forward soon on a pilot.

It's here , the question is the extent to which

no answer

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42| MAJOR ISSUES IMPEDING BETTER TRANSMISSION AND DISTRIBUTION IN NORTH AMERICA TODAY [1 = LOWEST, 9 = HIGHEST]

Total Respondents	9
Lack of investment capital	74
Lack of political or regulatory support for change	53
Aging Workforce issues	52
Relentless cost pressures ;	60
Lack of standards	61
Lack of visibility into customer behavior	27
Lack of off the shelf equipment w ith a proven trac	53
Little or no predictability of usage	36
Little or no predictability of capacity demand	34
Cyber Security	45

Comments

Calculation used

Q42.1, Q42.2, Q42.3, Q42.4, Q42.5, Q42.6, Q42.7, Q42.8, Q42.9, Q42.10

Legends									
Lack of investment capital	10	10	4	10	1	10	9	10	10
Lack of political or regulatory support for change	5	7	9	1	3	6	6	9	7
Aging Workforce issues	7	6	6	2	10	9	4	2	6
Relentless cost pressures ;	6	2	10	5	2	8	10	8	9
Lack of standards	9	9	8	9	5	4	7	5	5

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Lack of visibility into customer behavior	3	4	3	3	6	5	1	1	1
Lack of off the shelf equipment with a proven trac	8	9	5	8	4	3	6	7	2
Little or no predictability of usage	1	3	2	4	8	7	5	3	3
Little or no predictability of capacity demand	2	5	1	6	9	1	2	4	4
Cyber Security	4	1	7	7	7	2	3	6	8

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Financial

Distribution Line O&M Expense per End-Use Customer

Distribution Lines O&M Expense per Circuit Mile

Distribution Lines O&M Expense per MWh Sold

Distribution Lines O&M Expense per Asset

3-Yr Avg Distribution Line Capital Spending less New Business per Asset

Distribution Reliability

1| SAIFI (Including Major Events and Planned Interruptions)

1| SAIFI (Excluding Major Events and Planned Interruptions)

1| CAIDI (Including Major Events and Planned Interruptions)

1| CAIDI (Excluding Major Events and Planned Interruptions)

1| SAIDI (Including Major Events and Planned Interruptions)

1| SAIDI (Excluding Major Events and Planned Interruptions)

5| SAIDI Percent of minutes by cause

8| Percent of customers with <3 interruptions last year

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DISTRIBUTION LINE O&M EXPENSE PER END-USE CUSTOMER



Mean Quartile	
Mean	$85.65
Quartile 1	$62.20
Quartile 2:	$80.19
Quartile 3:	$107.67

Comments

Calculation used

Q5.8A / (T&D Dist End Use Customers)

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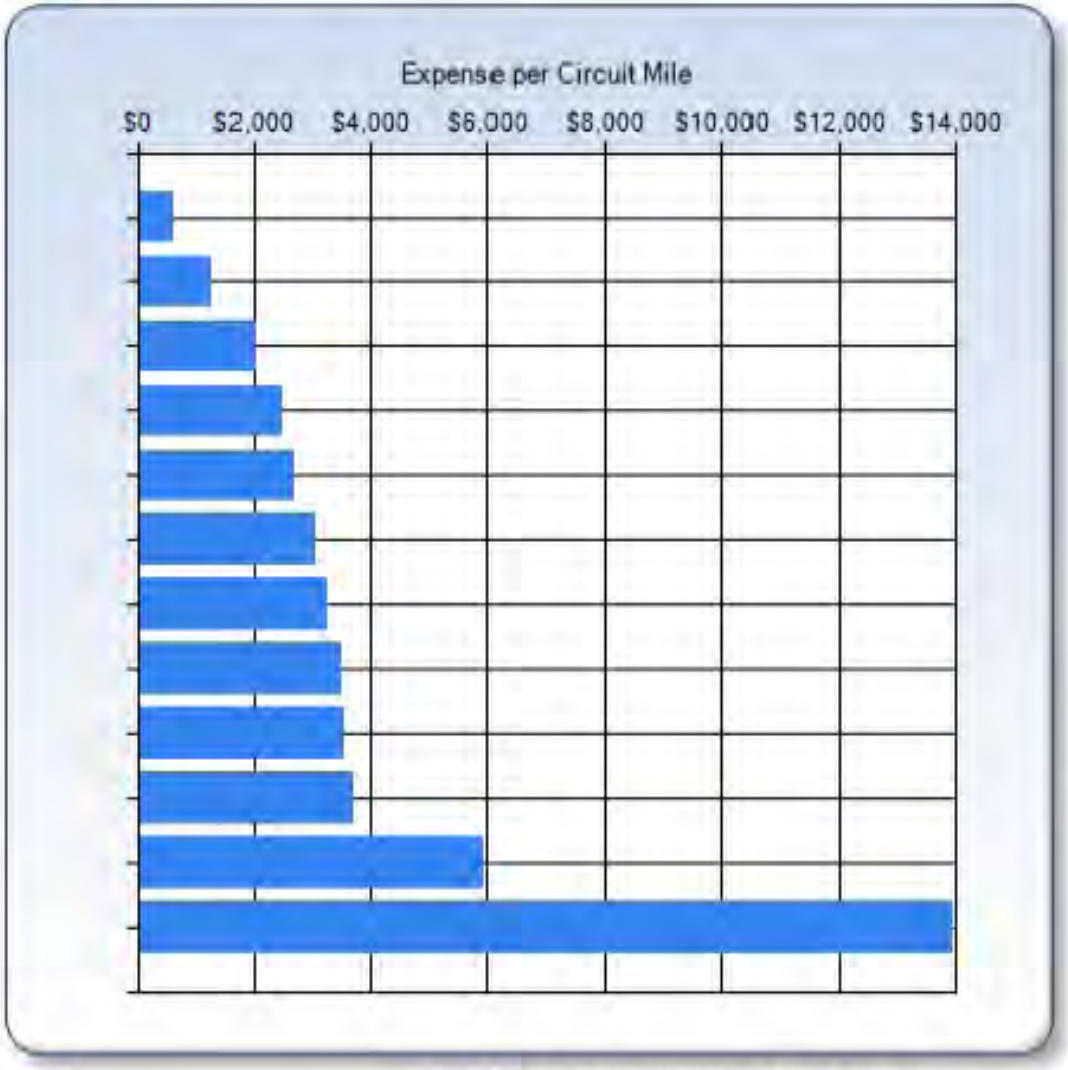
DISTRIBUTION LINES O&M EXPENSE PER CIRCUIT MILE



Mean Quartile	
Mean	$3,837
Quartile 1	$2,356
Quartile 2:	$3,154
Quartile 3:	$3,562

Comments

Calculation used

Q5.8A / (Dist Circ Miles)

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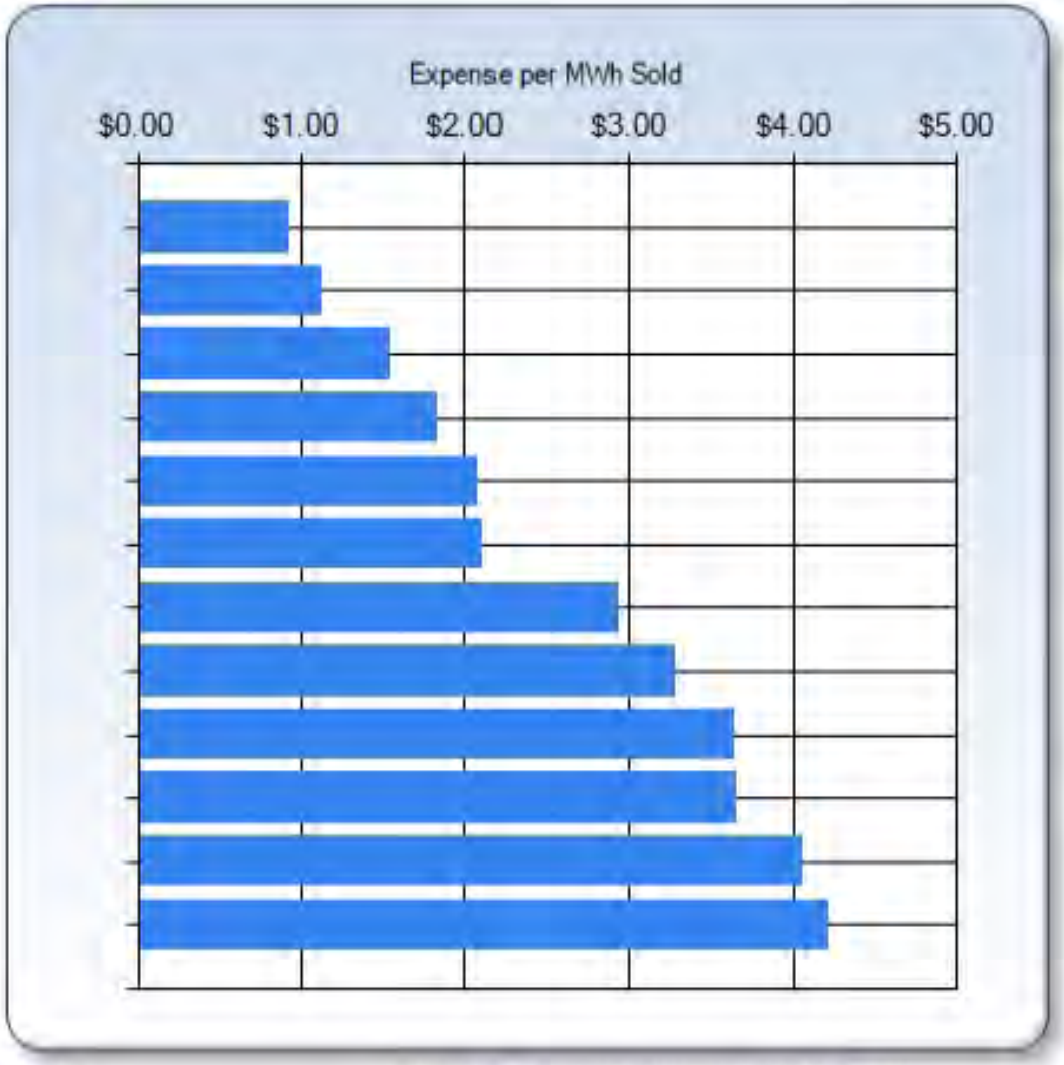
DISTRIBUTION LINES O&M EXPENSE PER MWH SOLD



Mean Quartile	
Mean	$2.62
Quartile 1	$1.76
Quartile 2:	$2.53
Quartile 3:	$3.65

Comments

Calculation used

Q5.8A / Q3.1A

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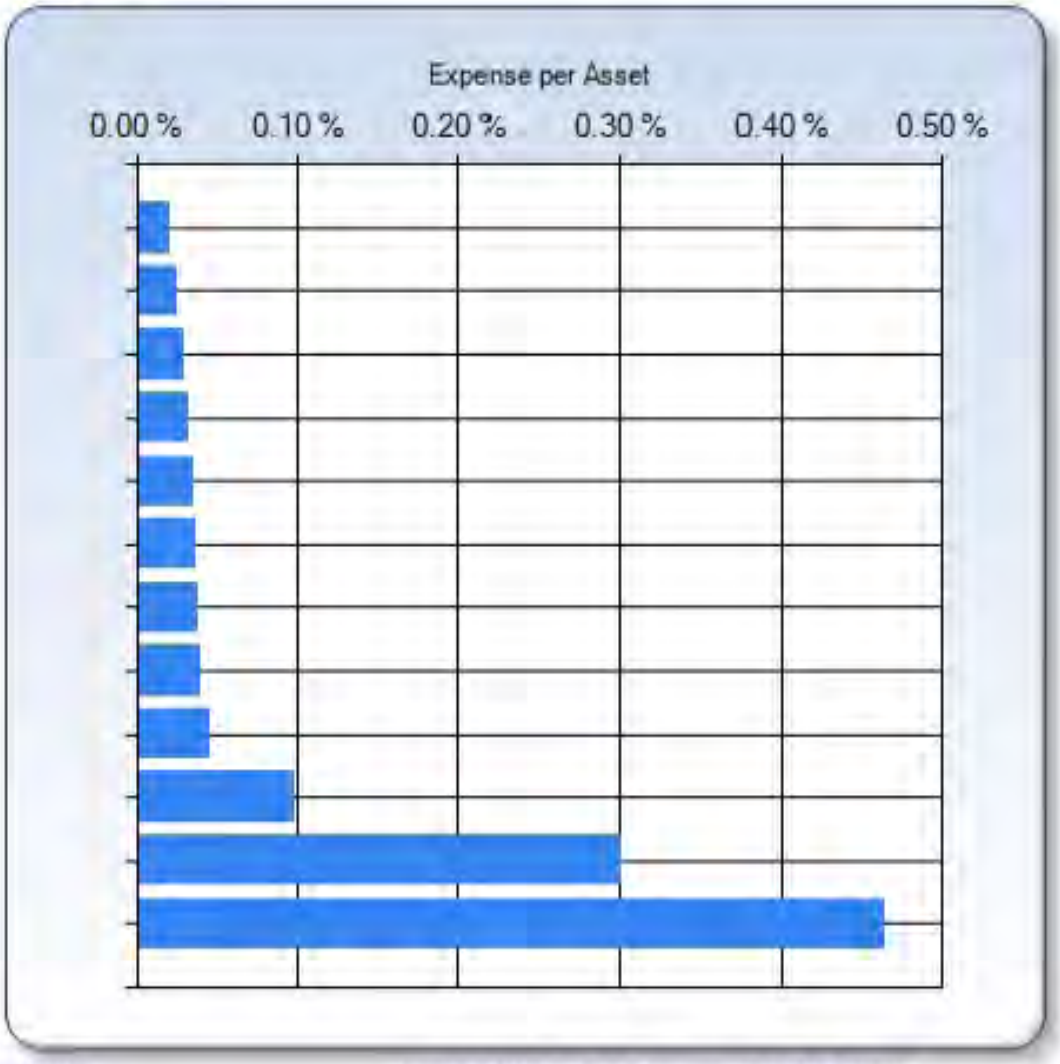
DISTRIBUTION LINES O&M EXPENSE PER ASSET



Mean Quartile	
Mean	0.098 %
Quartile 1	0.032 %
Quartile 2:	0.038 %
Quartile 3:	0.060 %

Comments

Calculation used

Q5.8A / Q16.1A

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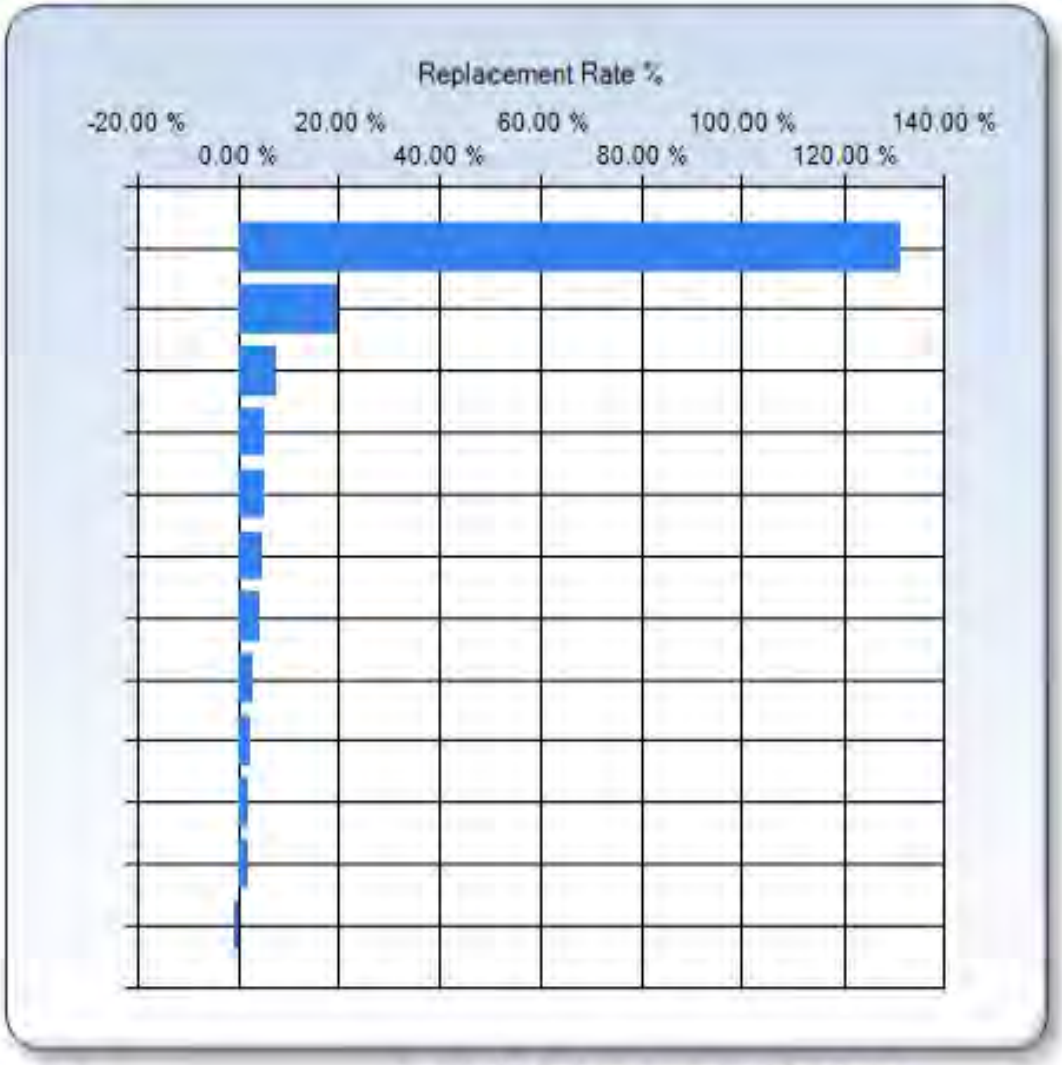
3-YR AVG DISTRIBUTION LINE CAPITAL SPENDING LESS NEW BUSINESS PER ASSET



Mean Quartile	
Mean	15.57 %
Quartile 1	5.86 %
Quartile 2:	4.44 %
Quartile 3:	2.42 %

Comments

Median asset replacement rate is 4.5%

Calculation used

((((Q1.7A - Q9.1A - Q1.5A) / Q16.1A) + ((Q1.7B - Q9.1B - Q1.5B) / Q16.1B) + ((Q1.7C - Q9.1C - Q1.5C) / Q16.1C)) / 3) * 100

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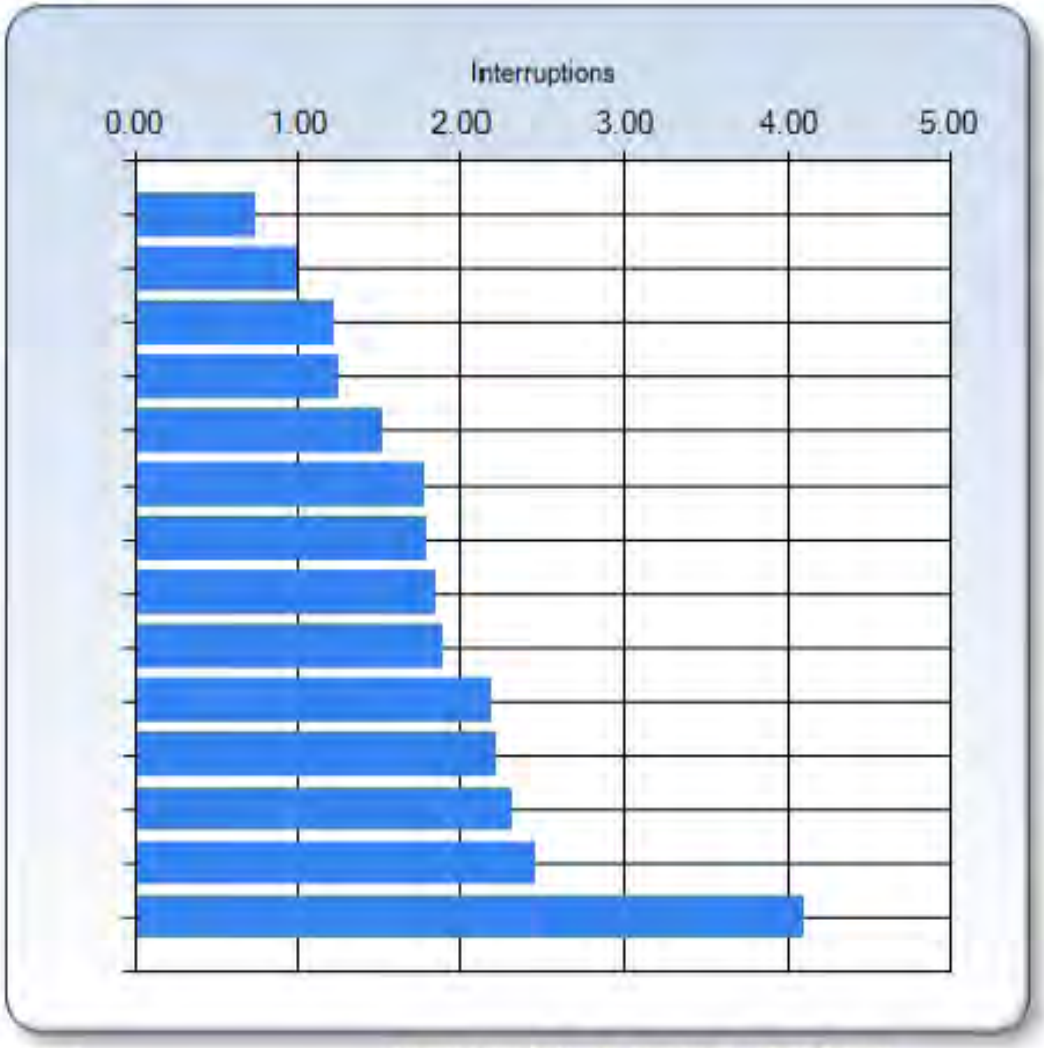
1| SAIFI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1.88
Quartile 1	1.32
Quartile 2:	1.83
Quartile 3:	2.21

Comments

Calculation used

Q1.2A

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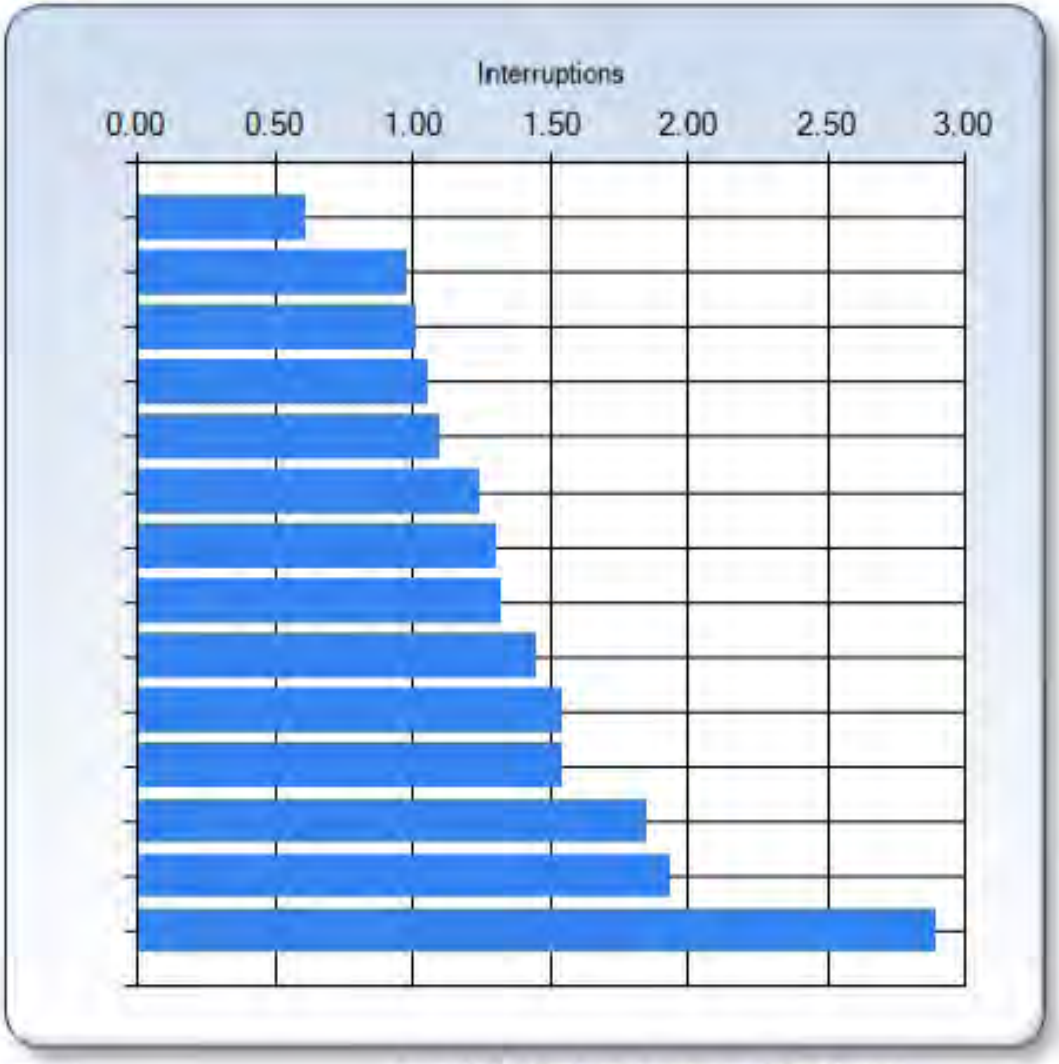
1| SAIFI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	1.42
Quartile 1	1.07
Quartile 2:	1.31
Quartile 3:	1.54

Comments

Calculation used

Q1.2B

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1| CAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	140
Quartile 1	106
Quartile 2:	124
Quartile 3:	177

Comments

Calculation used

Q1.3A

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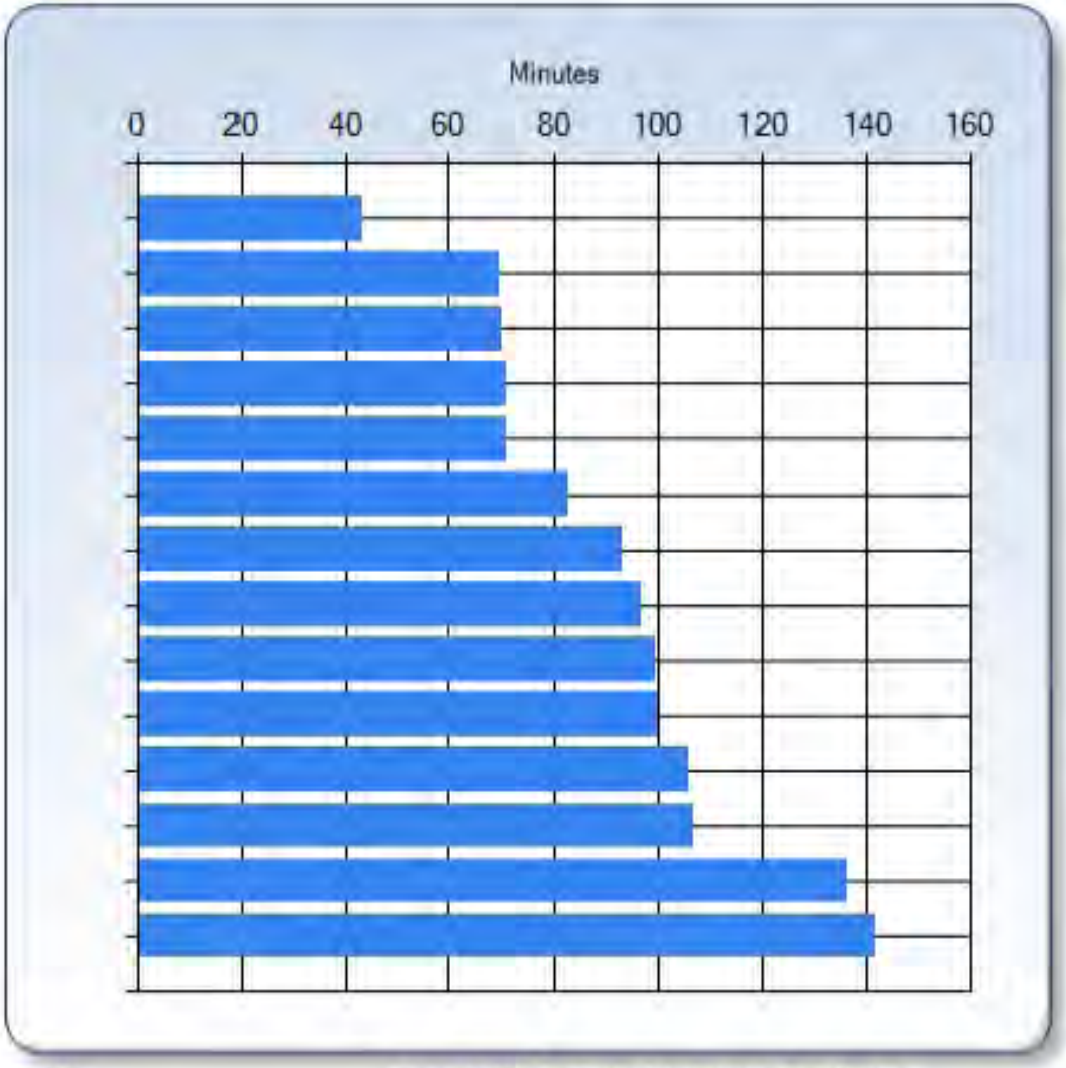
1| CAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	92
Quartile 1	71
Quartile 2:	95
Quartile 3:	105

Comments

Calculation used

Q1.3B

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1| SAIDI (INCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	275
Quartile 1	126
Quartile 2:	239
Quartile 3:	331

Comments

Calculation used

Q1.1A

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1| SAIDI (EXCLUDING MAJOR EVENTS AND PLANNED INTERRUPTIONS)



Mean Quartile	
Mean	135
Quartile 1	86
Quartile 2:	108
Quartile 3:	142

Comments

Calculation used

Q1.1B

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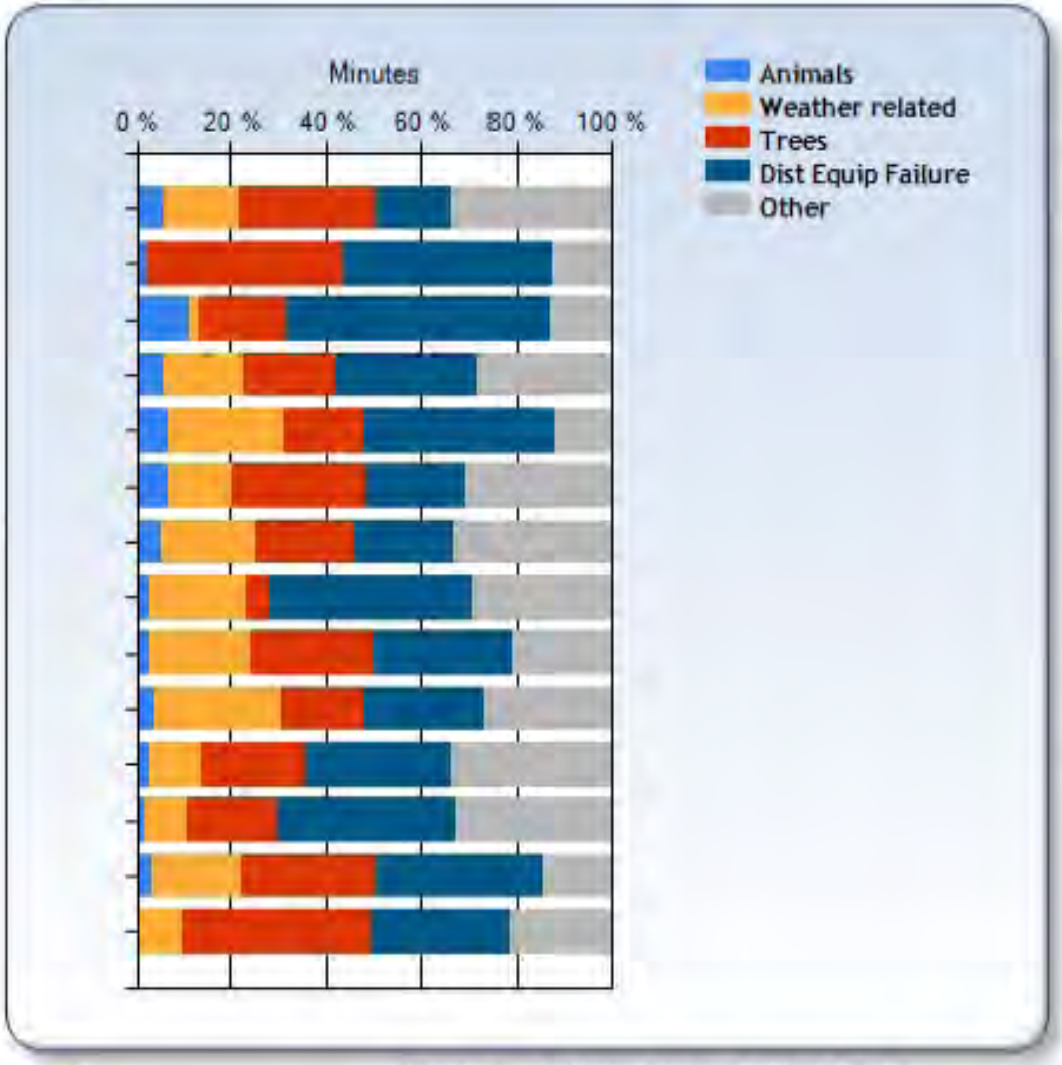
5| SAIDI PERCENT OF MINUTES BY CAUSE



Mean Quartile	
Mean	118 %
Quartile 1	113 %
Quartile 2:	104 %
Quartile 3:	77 %

Comments

Calculation used

Q5.5A, Q5.3A + Q5.4A, Q5.2A, Q5.6A, Q5.11A

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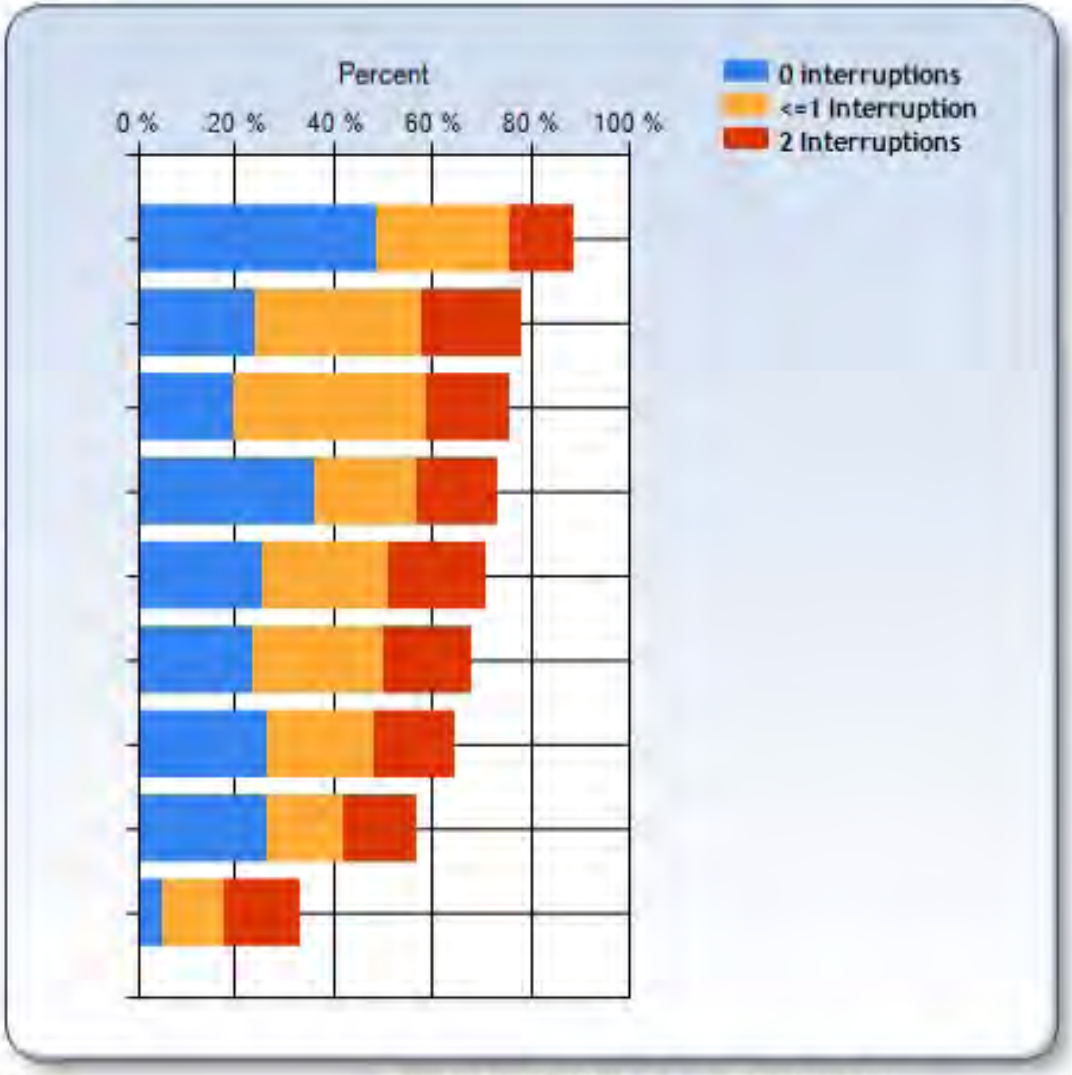
8| PERCENT OF CUSTOMERS WITH <3 INTERRUPTIONS LAST YEAR



Mean Quartile	
Mean	68 %
Quartile 1	76 %
Quartile 2:	71 %
Quartile 3:	65 %

Comments

Calculation used

Q8.1A, Q8.1A, Q8.1A

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1| Recordable Incident Rate: Substations
1| Recordable Incident Rate: Transmission Lines
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1| Lost Time Incident Rate: Distribution Lines
1| Lost Time Incident Rate: Substations
1| Lost Time Incident Rate: Transmission Lines
1| Lost Time Severity Rate: Total T&D
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1| Vehicle Incident Rate: Transmission Lines
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8| How do you manage the safety performance of contractors [e.g. monitoring, incentives, selection criteria]
9| Safety statistics are influenced by your following policies: Doctors visits following an at-work injury
9| Safety statistics are influenced by your following policies: Working at reduced level following at at-work injury

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10| Rules and policies that affect return to work: Light duty work rules

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11| Safety-related initiatives successful in reducing injuries for personnel Field

11| Safety-related initiatives successful in reducing injuries for personnel Office

12| What wellness [physical and mental] initiatives or cultural changes have been successful in reducing illnesses for personnel? Include date of inception.

13| Corporate goal regarding changes to safety

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1| RECORDABLE INCIDENT RATE - TOTAL T&D



Mean Quartile	
Mean	3.99
Quartile 1	1.66
Quartile 2:	3.15
Quartile 3:	4.10

Comments

Calculation used

Q1.1A

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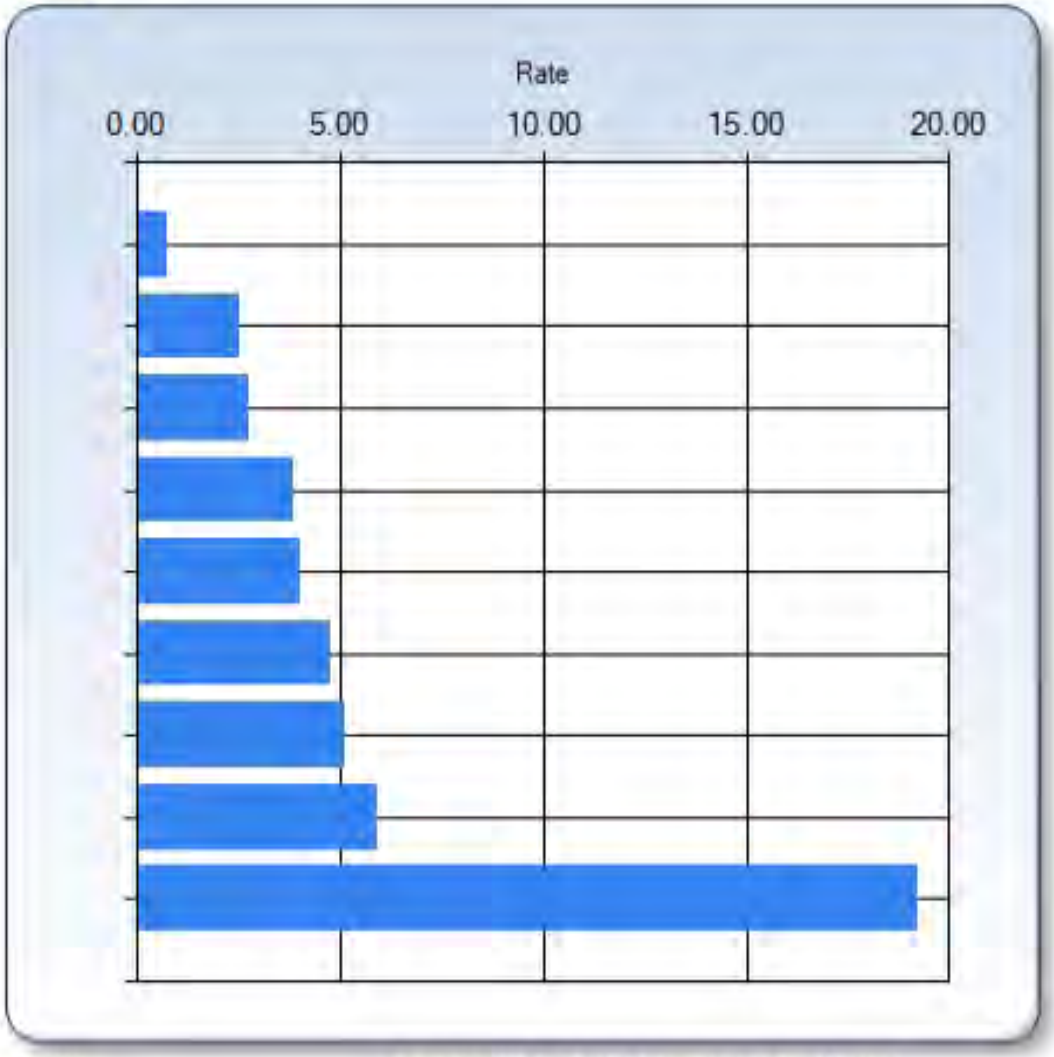
1| RECORDABLE INCIDENT RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	5.44
Quartile 1	2.74
Quartile 2:	4.05
Quartile 3:	5.13

Comments

Calculation used

Q1.1D

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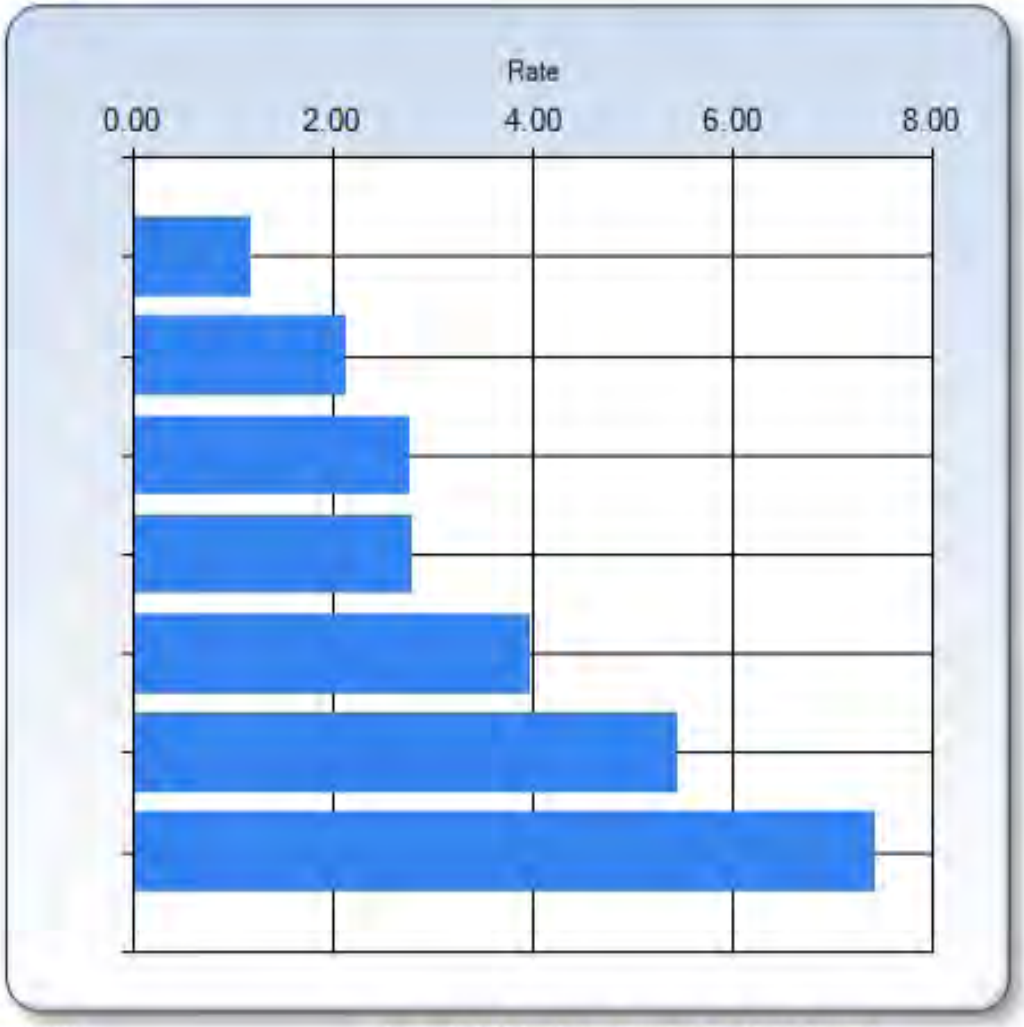
1| RECORDABLE INCIDENT RATE: SUBSTATIONS



Mean Quartile	
Mean	3.68
Quartile 1	2.46
Quartile 2:	2.81
Quartile 3:	4.72

Comments

Calculation used

Q1.1C

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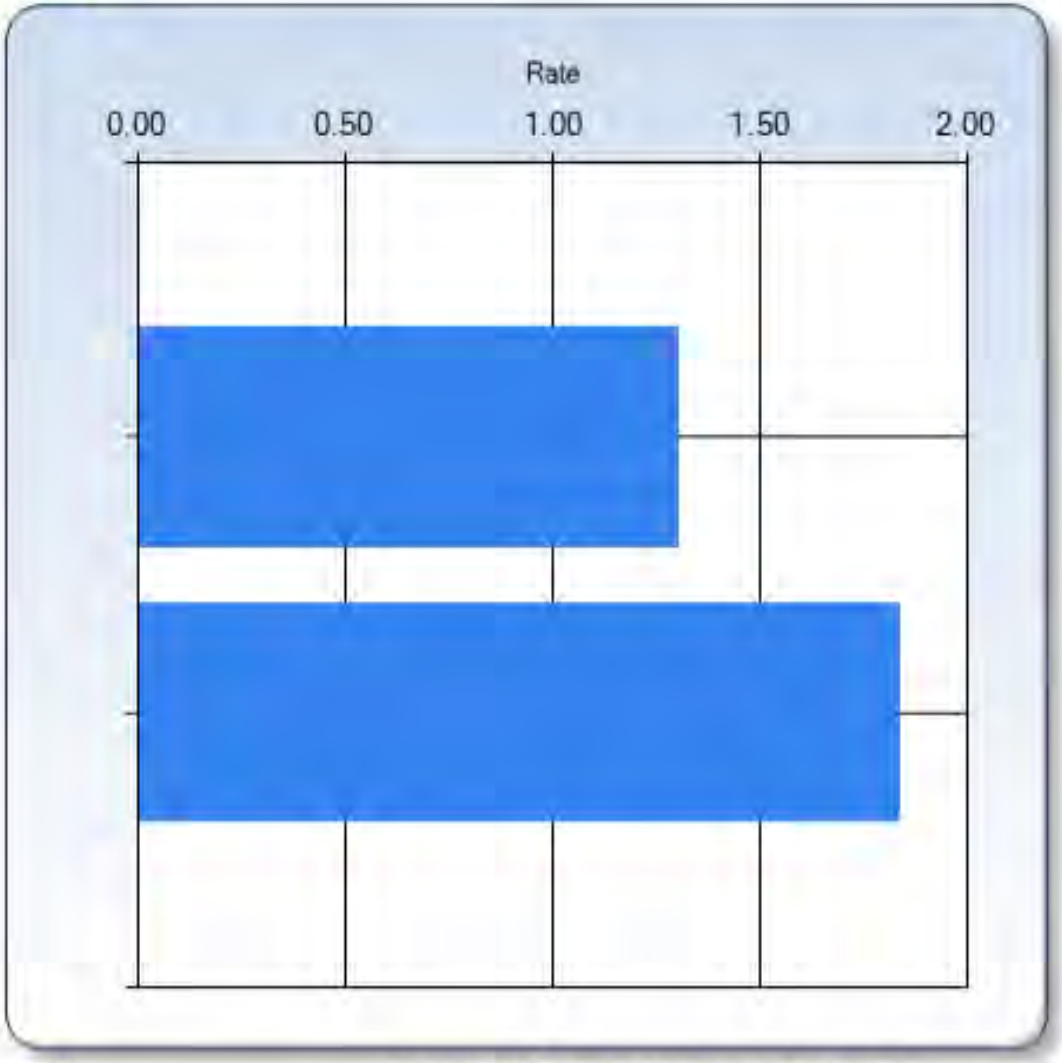
1| RECORDABLE INCIDENT RATE: TRANSMISSION LINES



Mean Quartile	
Mean	1.58
Quartile 1	1.44
Quartile 2:	1.58
Quartile 3:	1.71

Comments

Calculation used

Q1.1B

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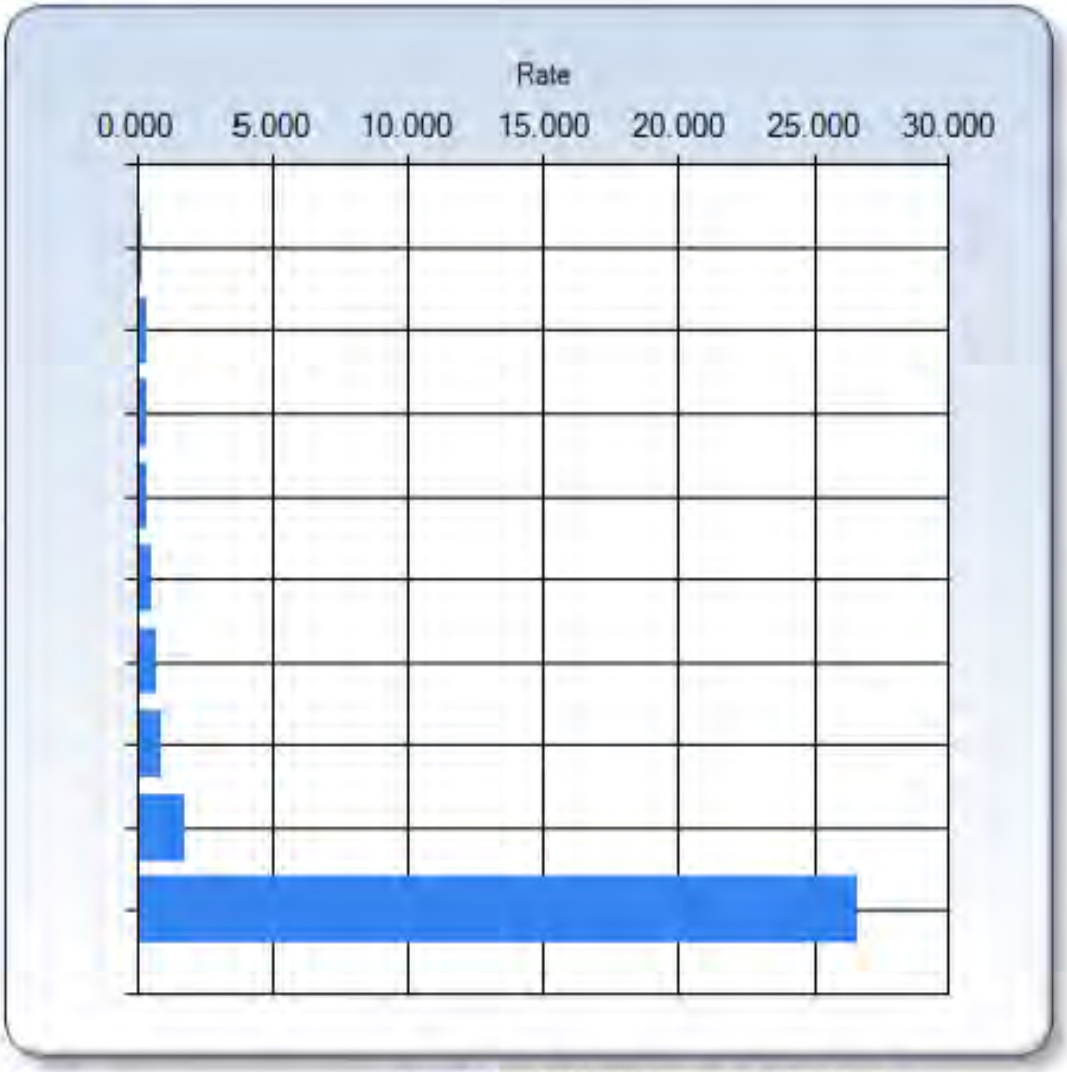
1| LOST TIME INCIDENT RATE: TOTAL T&D



Mean Quartile	
Mean	3.555
Quartile 1	0.376
Quartile 2:	0.570
Quartile 3:	0.890

Comments

Calculation used

Q1.2A

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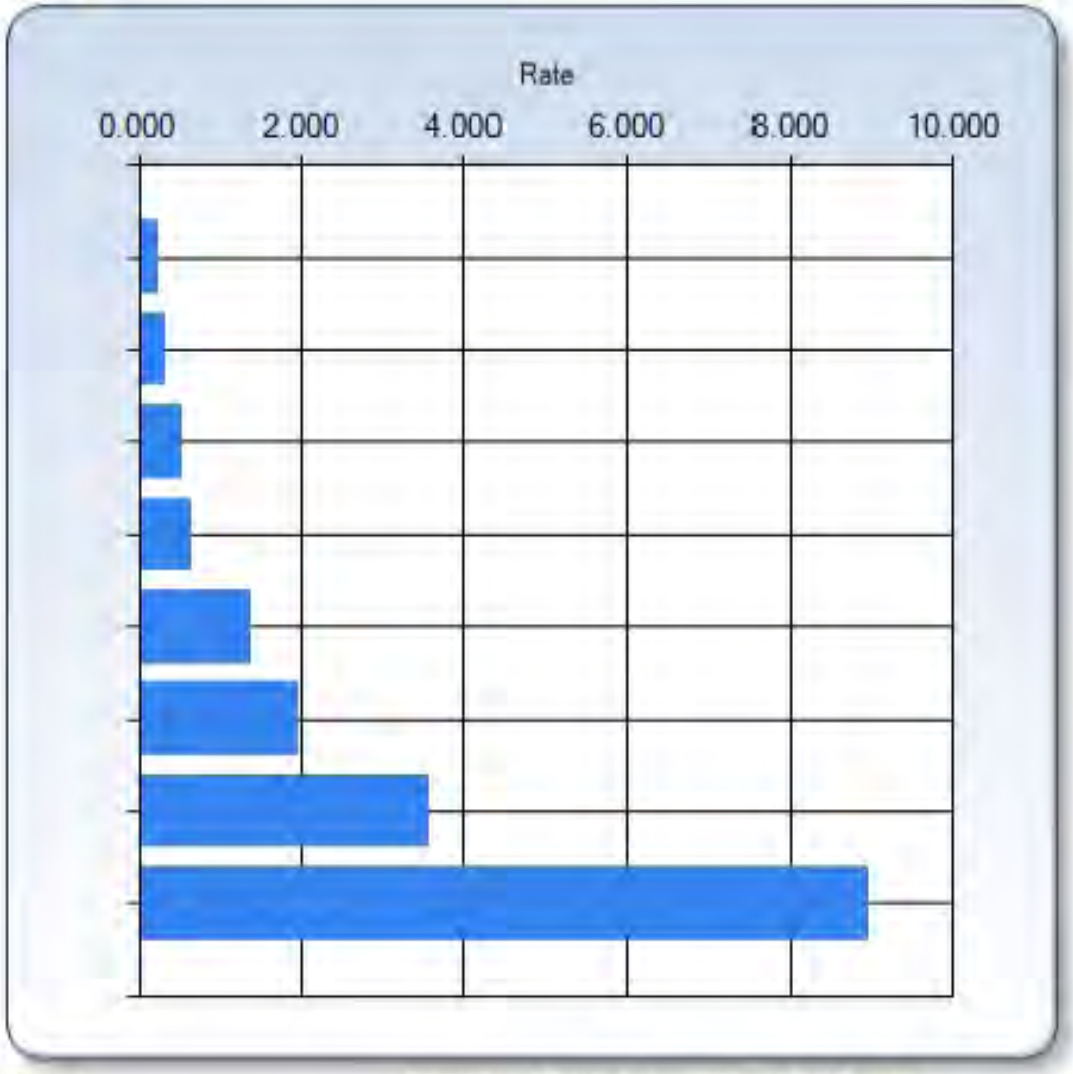
1| LOST TIME INCIDENT RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	2.210
Quartile 1	0.499
Quartile 2:	1.015
Quartile 3:	2.358

Comments

Calculation used

Q1.2D

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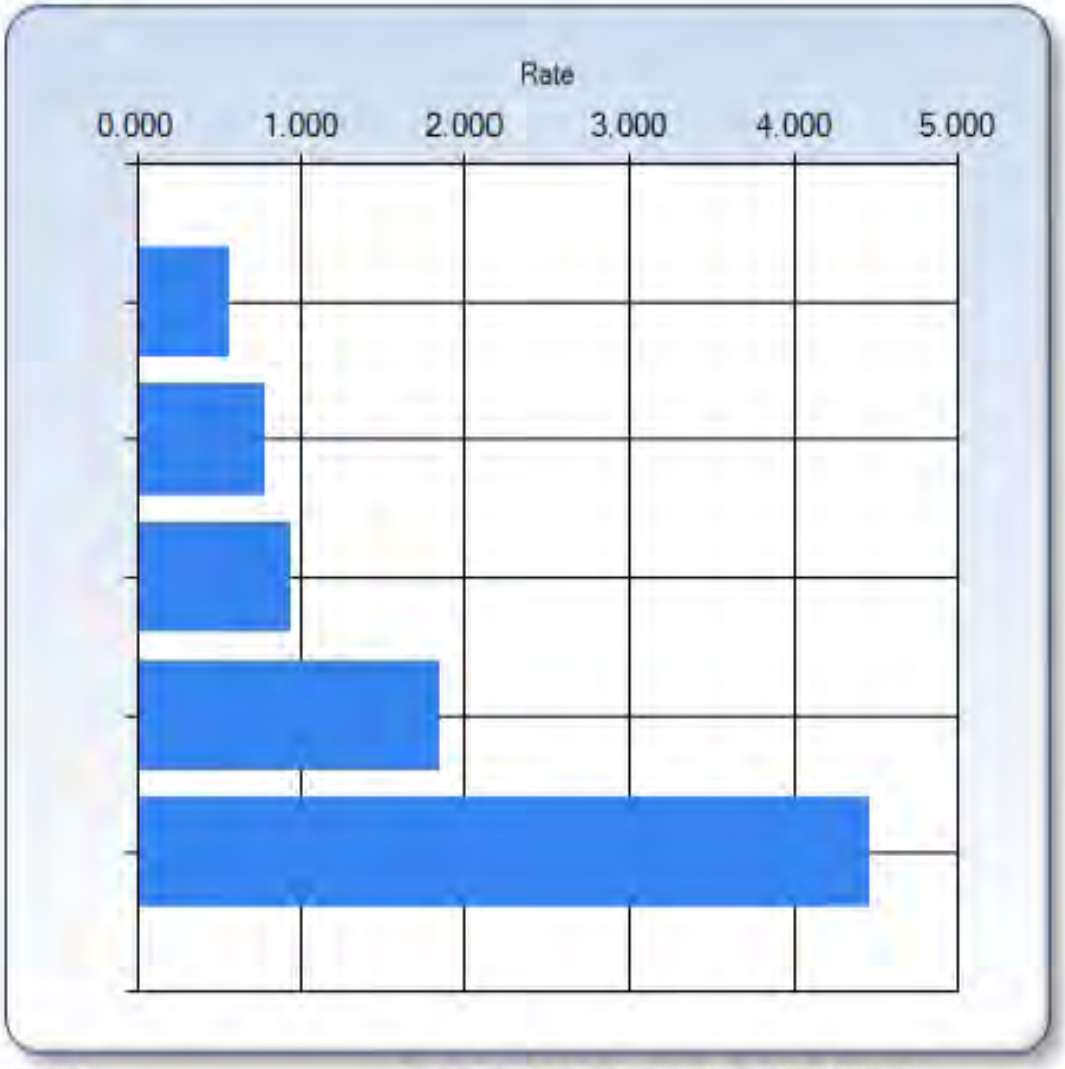
1| LOST TIME INCIDENT RATE: SUBSTATIONS



Mean Quartile	
Mean	1.720
Quartile 1	0.780
Quartile 2:	0.940
Quartile 3:	1.850

Comments

Calculation used

Q1.2C

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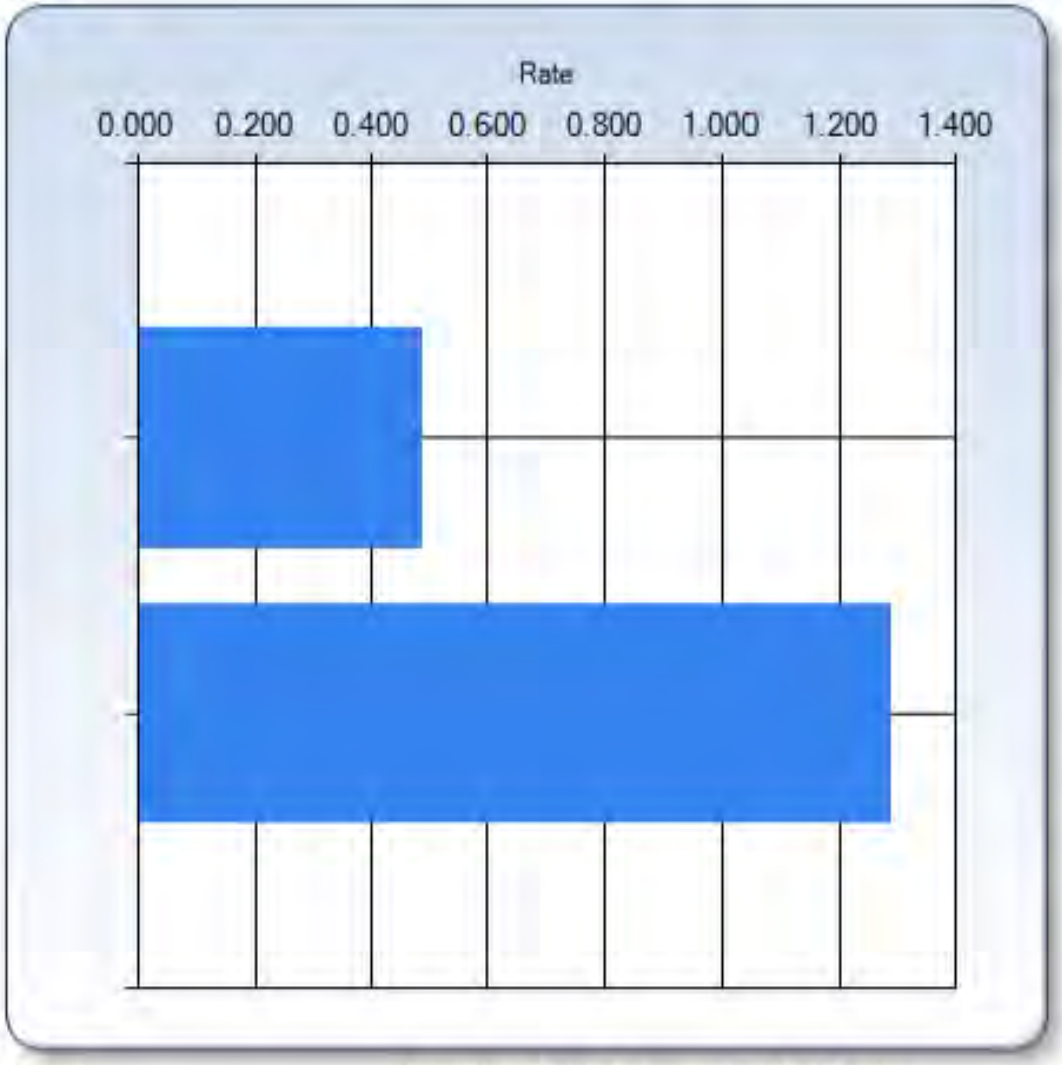
1| LOST TIME INCIDENT RATE: TRANSMISSION LINES



Mean Quartile	
Mean	0.890
Quartile 1	0.690
Quartile 2:	0.890
Quartile 3:	1.090

Comments

Calculation used

Q1.2B

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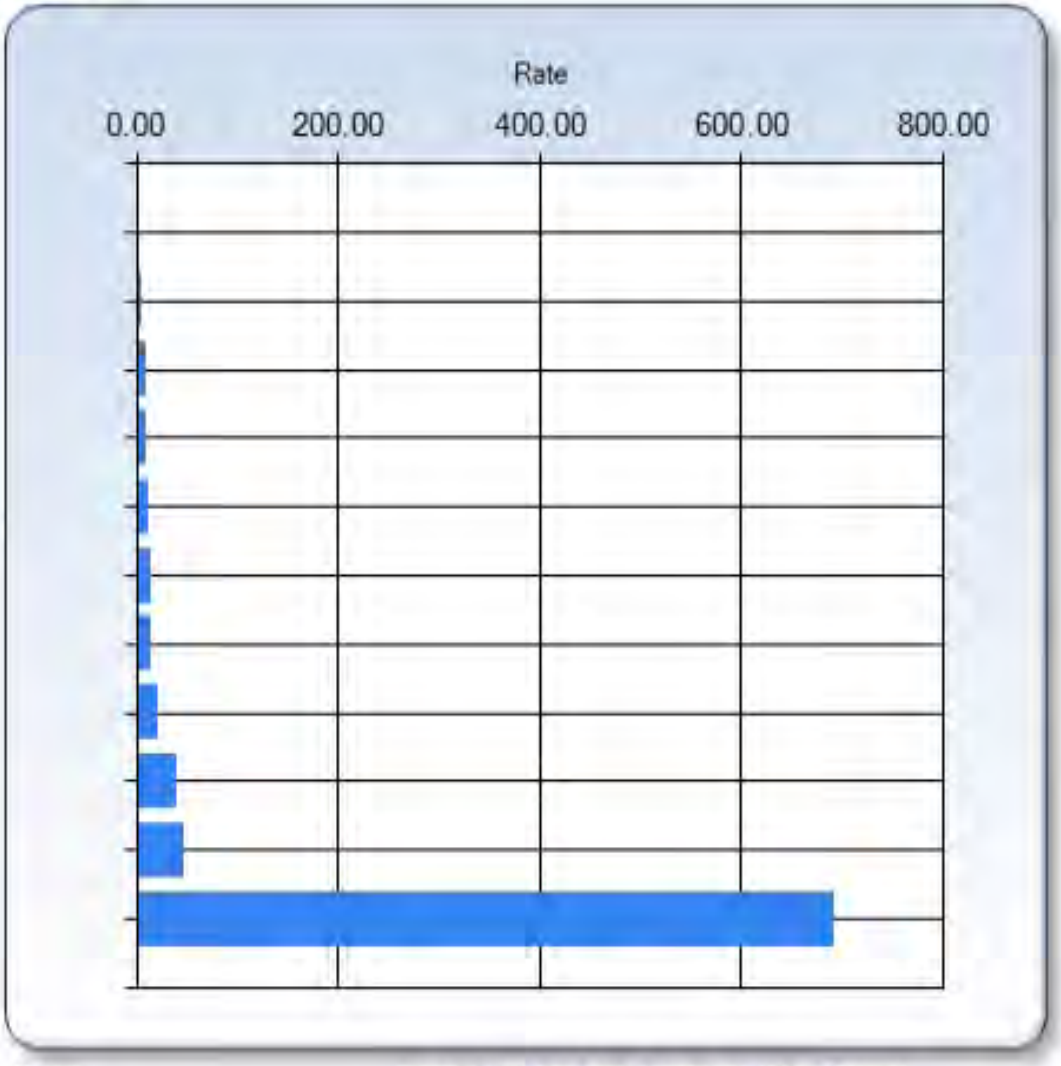
1| LOST TIME SEVERITY RATE: TOTAL T&D



Mean Quartile	
Mean	79.65
Quartile 1	10.32
Quartile 2:	14.20
Quartile 3:	32.10

Comments

Calculation used

Q1.3A

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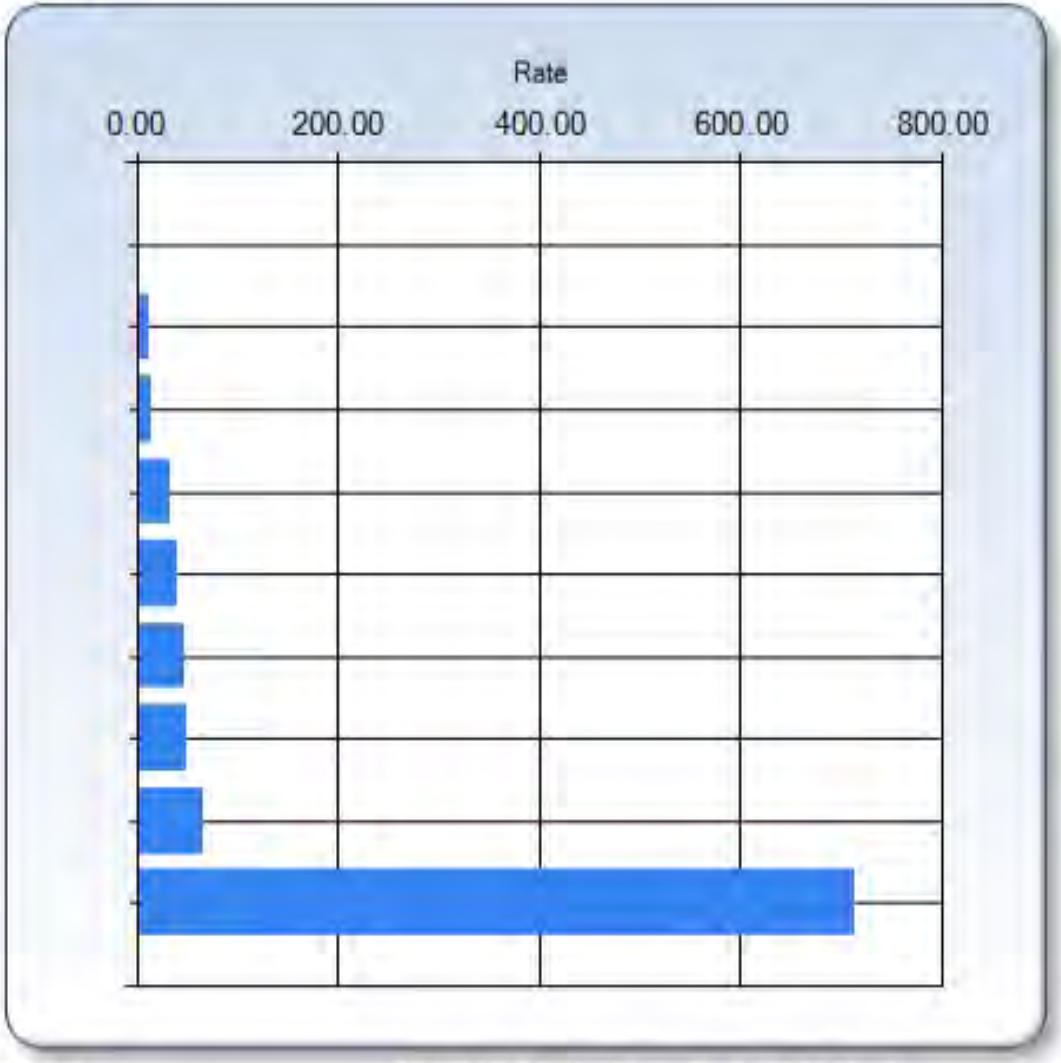
1| LOST TIME SEVERITY RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	109.50
Quartile 1	15.93
Quartile 2:	41.05
Quartile 3:	50.31

Comments

Calculation used

Q1.3D

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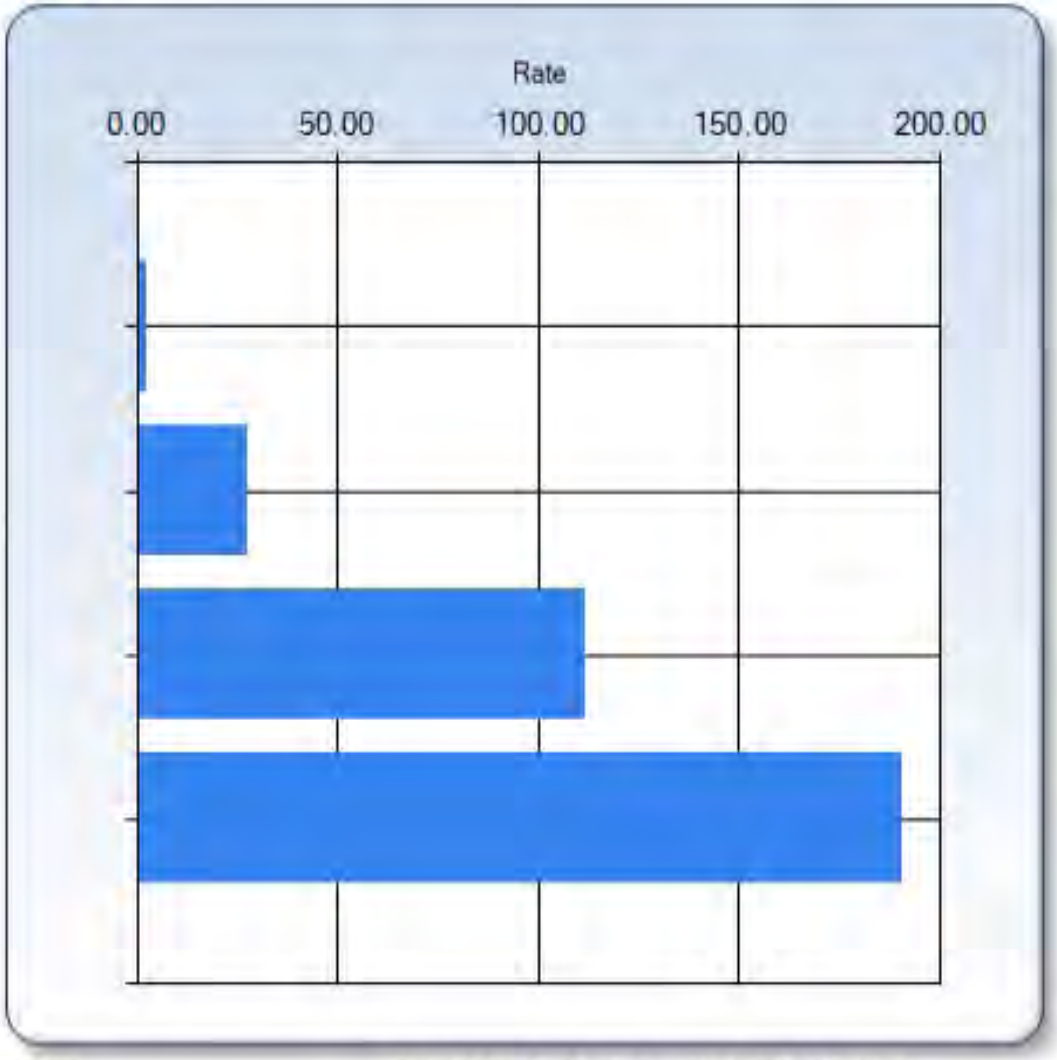
1| LOST TIME SEVERITY RATE: SUBSTATIONS



Mean Quartile	
Mean	83.00
Quartile 1	21.08
Quartile 2:	69.36
Quartile 3:	131.27

Comments

Calculation used

Q1.3C

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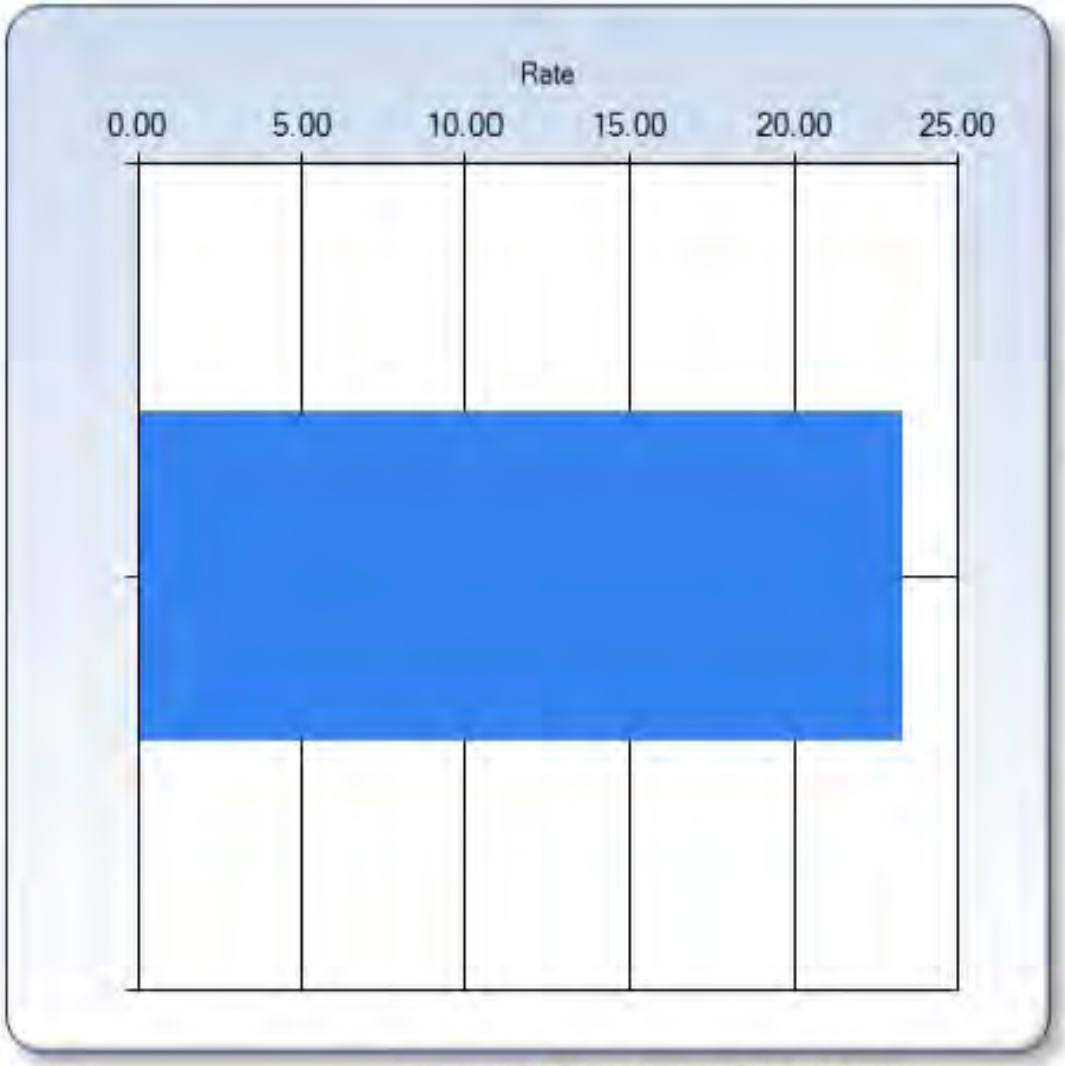
1| LOST TIME SEVERITY RATE: TRANSMISSION LINES



Mean Quartile	
Mean	23.36
Quartile 1	23.36
Quartile 2:	23.36
Quartile 3:	23.36

Comments

Calculation used

Q1.3B

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1| VEHICLE INCIDENT RATE: TOTAL T&D



Mean Quartile	
Mean	20.34
Quartile 1	2.68
Quartile 2:	6.21
Quartile 3:	8.31

Comments

Calculation used

Q1.4A

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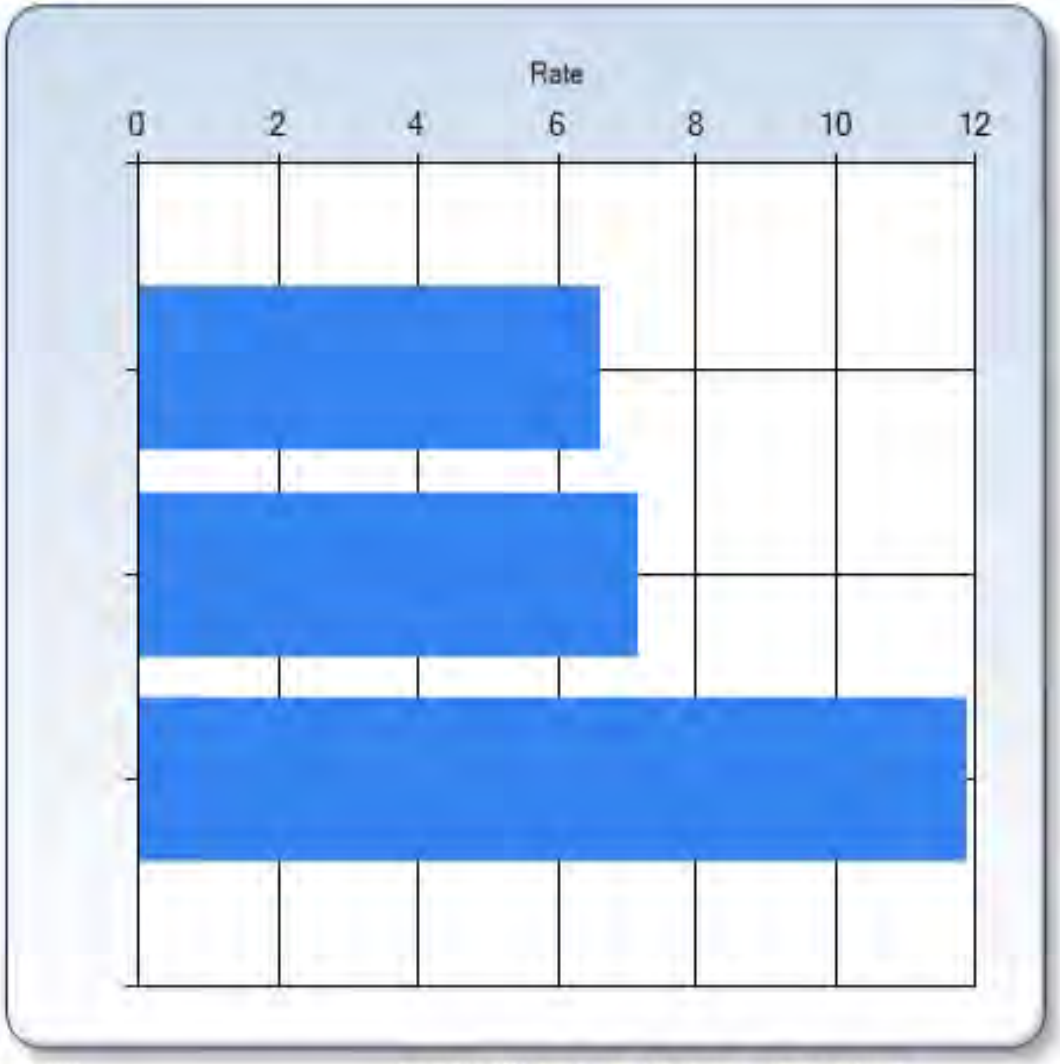
1| VEHICLE INCIDENT RATE: DISTRIBUTION LINES



Mean Quartile	
Mean	8.56
Quartile 1	6.90
Quartile 2:	7.16
Quartile 3:	9.52

Comments

Calculation used

Q1.4D

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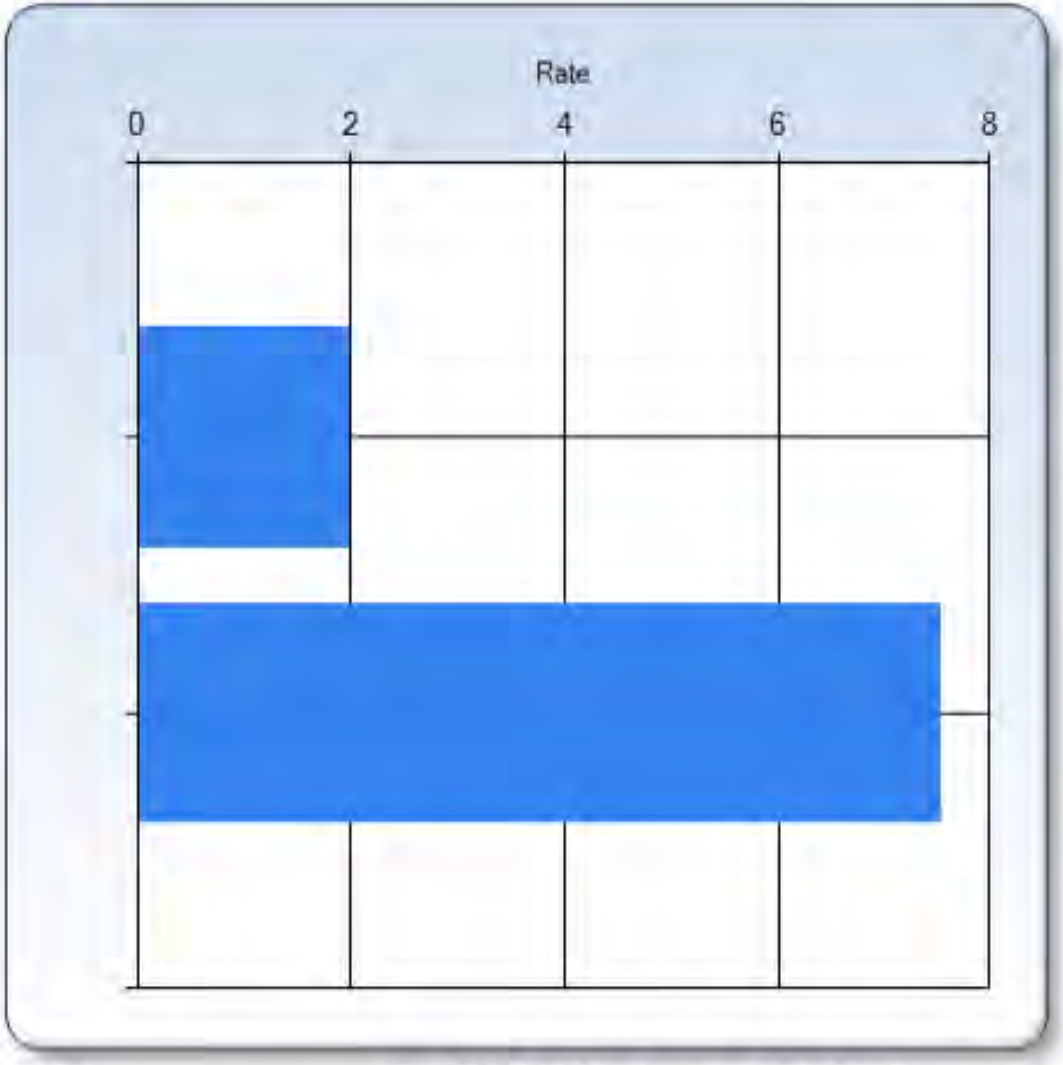
1| VEHICLE INCIDENT RATE: SUBSTATIONS



Mean Quartile	
Mean	4.78
Quartile 1	3.39
Quartile 2:	4.78
Quartile 3:	6.17

Comments

Calculation used

Q1.4C

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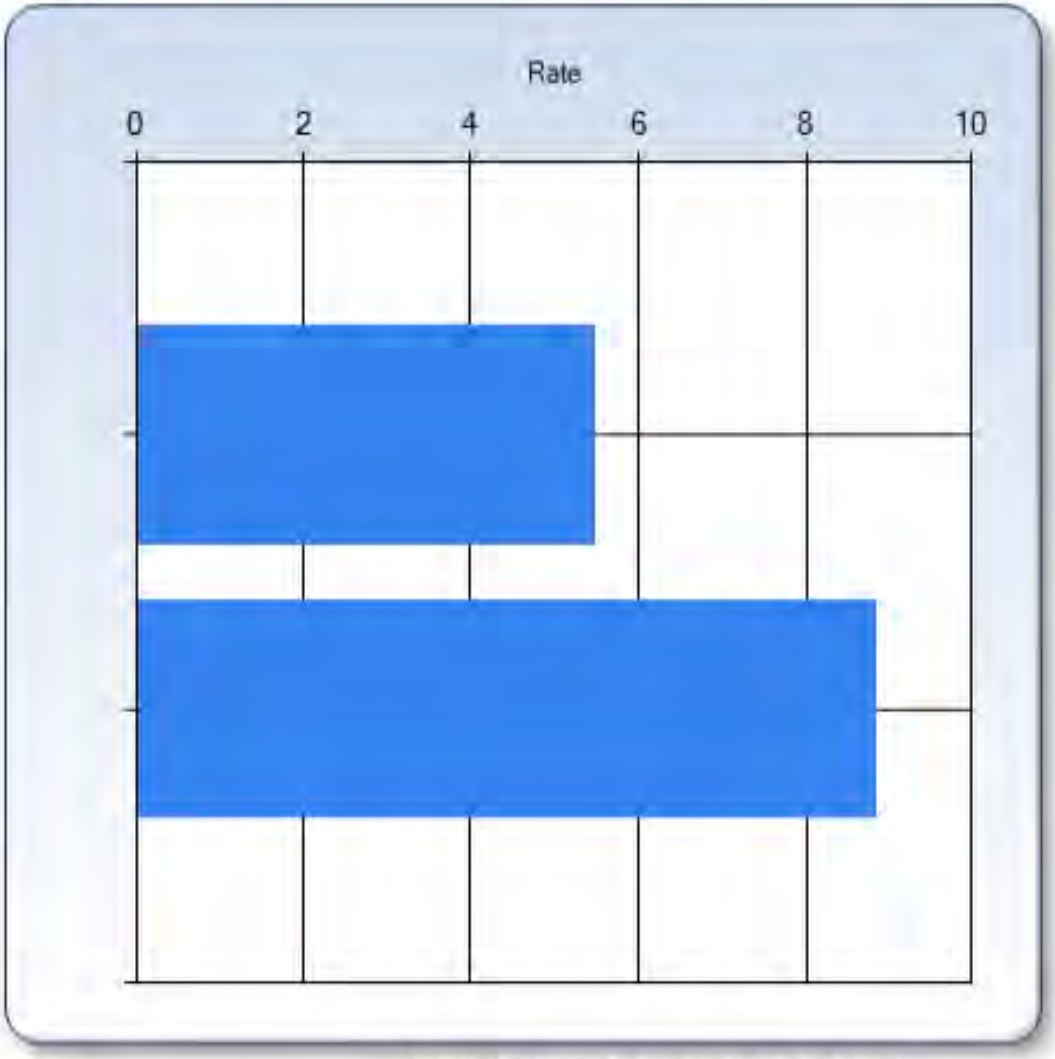
1| VEHICLE INCIDENT RATE: TRANSMISSION LINES



Mean Quartile	
Mean	7.18
Quartile 1	6.34
Quartile 2:	7.18
Quartile 3:	8.01

Comments

Calculation used

Q1.4B

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5| DO YOU TRACK THE SAFETY STATISTICS FOR YOUR CONTRACTORS [TURN-KEY CONTRACTS, NOT CONTRACT EMPLOYEES]?

Total Respondents	16
Yes	81.25%
No	18.75%

Comments

Calculation used

Q5.1, Q5.2

Legends																
Yes	♦	♦	♦	♦		♦	♦	♦	♦	♦		♦		♦	♦	♦
No					♦						♦		♦			

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6| DO YOU HAVE INCENTIVES OR PENALTIES ATTACHED TO THE SAFETY STATISTICS OF YOUR CONTRACTORS?

Total Respondents	15
Yes	40%
No	60%

Comments

Calculation used

Q6.1, Q6.2



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7| DO YOU USE CONTRACTOR SAFETY PERFORMANCE AS ONE OF YOUR SELECTION CRITERIA WHEN SELECTING CONTRACTORS?

Total Respondents	15
Yes	73.33%
No	26.67%

Comments

Calculation used

Q7.1, Q7.2

Legends															
Yes	♦		♦	♦	♦	♦	♦	♦			♦		♦	♦	♦
No		♦							♦	♦		♦			

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8| HOW DO YOU MANAGE THE SAFETY PERFORMANCE OF CONTRACTORS [E.G. MONITORING, INCENTIVES, SELECTION CRITERIA]

	Responses	Comments
Total Participants	16	
Number of Respondants	12	

Calculation used

Q8.1

Response

Quarterly meetings to review Key Selection Indices. Experience Modification rate of 1.0 or less is the safety target sought for contractor selection.

Monitoring

Evaluate them on an annual basis as in the contract

Monitoring

Set expectations in contract, contract administrator/officer assigned (monitoring), selection criteria, commitment to demanding equal level of safety as employees

All accidents are reported to us through a w ritten report. Near misses are not reported unless there is a flash involved.

Weekly safety reporting and statistics; safety representatives

Weekly reporting, safety representative guidance

Evaluation of contractor safety performance and health & safety Management System prior to hire; Monitor contractor as w ork proceeds

Monitoring (field superviosors, 3rd party safety audits), incentives (bonuses and contractor penalties), performance scorecards.

Monitor / Some Incentives

On-going monitoring; performance incentives as part of the contract.

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9| SAFETY STATISTICS ARE INFLUENCED BY YOUR FOLLOWING POLICIES: DOCTORS VISITS FOLLOWING AN AT-WORK INJURY

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q9.1

Response

Nursing staff/supervisor is involved with cases requiring medical treatment. A Return to Work Recommendations form letter is provided.

Reportable incident.

If the employee sees a doctor & is not given a prescription & released by the doctor to return to work, it is not a recorded injury. However, if the doctor gives the employee a prescription & they are able to return to work, it is a recordable injury. If the employee is unable to return to work due to the injury, the doctor is asked to send a written statement to that effect and it is recorded as a lost time injury.

A Return to Work program and Lost Time injury rate has been reduced beecause of effort to accommodate restricted duties.

Our safety statistics are not influenced buy this policy because we simply don't apply this policy in our company. If a worker is injured at work, it's the employee's doctor who is responsable of treating the victim and not the utility doctor.

Often, doctors will prescibe the quick fix or preventive prescriptions and unnecessary time loss. Time loss after doctor's visit is excluded following return to work.

We give Medical Assistance Guidelines and documentation to the attending medical personnel to promote a better understanding of our commitment to returning the employee to work including light duty.

Doctor's visit required after each injury; Early & Safe return to work program to bring worker back to work sooner and reduces lost time

We follow the OSHA definitions and guidelines when keeping safety statistics (recordables, lost time etc.)

We encourage to report every incident to ensure that we can get early intervention from a medical perspective

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9| SAFETY STATISTICS ARE INFLUENCED BY YOUR FOLLOWING POLICIES: WORKING AT REDUCED LEVEL FOLLOWING AT AT-WORK INJURY

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q9.2

Response

Nursing staff/supervisor is involved with cases requiring medical treatment. They will assess the employee's limitations and determine if suitable work is available within the limitations for the anticipated duration of the limitations.

Increases DART

Is considered a recordable injury, but not a lost time injury.

A Return to Work program and Lost Time injury rate has been reduced beecause of effort to accommodate restricted duties.

Restricted duty

Very few of our incidents result in restricted time or duties at this time. Whenever used, it should be closely monitored.

We give Medical Assistance Guidelines and documentation to the attending medical personnel to promote a better understanding of our commitment to returning the employee to work including light duty.

Require doctor's diagnosis prior to developing a return to work plan. This would include restricted work. Return worker to full duties as soon as possible

We follow the OSHA definitions and guidelines when keeping safety statistics (recordables, lost time etc.)

We find work for all restricted duty cases

We have a light duty and return to work program

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10| RULES AND POLICIES THAT AFFECT RETURN TO WORK: LIGHT DUTY WORK RULES

	Responses	Comments
Total Participants	18	
Number of Respondants	12	

Calculation used

Q10.1

Response

Depending on the nature of the case, the Supervisor shall as a minimum, contact the injured the day following the injury/illness and weekly until the injured appears ready to return to work. The Supervisor will then arrange to have the employee's condition evaluated by the Medical Services group to assess the employee's fitness to return to work. Case Management oversight is owned by our Medical Services department. A nurse/physician would review the case prior to allowing the employee to return to work.

A physician's statement is required that states the employee can return to full duty after a lost time injury or restricted duty. Management reserves the right to determine the duration of any Restricted Duty. In all cases, restricted duty will terminate when an employee has eocpleted the Elimination Period required to qualify for Long Term Disability benefits.

The medical provider is the ultimate decision maker on an employee returning to regular work. However, if the employee's restrictions do not hinder the employee from performing all aspects of their normal job as determined by the supervisor and the employee, the employee may resume regular work.

1) Since it's the employee's doctor who decides when the employee returns to regular, there is a reason to think that the return to regular work will done less rapidly. 2) Since the level of compensation received during work-related injury absence is 100 %, there is a reason to believe that the return of the employee will be done less rapidly.

At this time, simply collaboration and agreement by Manager, Employee, Medical Service Provider and RTW Facilitator, using communication and a functional assessment for the determination. HR may also get involved in complex cases.

The attending physician decides when an employee is relaesed to return wo work, both restricted and full releases. Supervisors provide

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our light duty guidelines to assist the attending physician's understanding of our light duty provisions and remains in continual communication with the employee about proper timing as to when to return to regular work.

Company abides by medical diagnosis and assigns light duty that is available. Doctor/medical writes light duty restrictions

Doctor writes light duty restrictions. Company abides by doctor's diagnosis and uses light duty that is available.

Return to work dependant on doctor's diagnosis; Dependant on the core duties of the work done by the worker.

M.D. decides depending on tasks or duties involved

The doctor decides when an employee returns to full-duty. We have return to work policy that requires doctor releases to com back to work for off the job injuries

This is a medical decision. The medical community determines the conditions upon which an employee may return to work. The company allows an employee to return to work if work is available that the employee is capable of performing withnot violating the medical restrictions.

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10| RULES AND POLICIES THAT AFFECT RETURN TO WORK: PERCENT OF COMPENSATION RECEIVED DURING WORK-RELATED INJURY ABSENCE

	Responses	Comments
Total Participants	18	
Number of Respondants	10	

Calculation used

Q10.2

Response

The City of seattle pays employees 80% of their normal w age tax free for 261 days follow ing w ork related injury. If the employee is off for more than 261 days the employee is paid the state mandated rate w hich could range form 60% to 75% of their w ages depending on the number of dependents.

Total compensation: 100 %

100% of normal net - and this provides no incentive to return to w ork.

If a w ork related injury determined to be compensable by the w orkers compensation carrier results in lost time, the w orkers' compensation carrier w ill pay the employee w eekly income benefits in the amount of 70-75% of the employee's average w eekly w age, not to exceed the maximum amount payable under the w orkers' compensation statute. If the employee is covered under the Company's Salary Continuation Policy, they may request the company to supplement the income benefits paid by the w orkers' comp carrier by an amount not to exceed the difference betw een the employee's income benefit and their pre-injury w age. If it is determined that the employee is not eligible for pay under the Companys' Salary Continuation policy, then the supplemental pay w ill not be a consideration for the employee and they w ill receive only the income benefits paided by the w orkers' compensation carrier fot the lost time.

Worker's Comp and the company pay 75% for some employees (125) and 80% for others (659, 197)

Worker's Comp and the company pay 75% for some employees (125) and 80% for others (659, 197).

100% - Company pays the difference betw een Worker's Comp and salary

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Represented - Workers compensation Non-represented - 100% on short term disability.

100

Employees wages are replaced until they are able to return to work.

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11| SAFETY-RELATED INITIATIVES SUCCESSFUL IN REDUCING INJURIES FOR PERSONNEL FIELD

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q11.1

Response

Since 2005, we have had these initiatives: Weekly safety conference calls; Area Safety Teams; ergonomic initiatives; Personal Safety Management Program: Behavioral Safety Programs; Employee Engagement efforts.

A Value Based Safety Program was started in Oct. 2006 & are beginning to see some success & improvement

Recognize individual participation in safety through Culture Change, Focus Team, Safety Training Camp,and Light Power and Pride initiatives. Employees that volunteer to get involved in safety are recognized with shirts, jackets, and mugs. Light Power and Pride offers a monetary recognition gift. Extending safety recognition to people who put in safety suggestions, reconize work place hadzards and report near misses. There will be a monthly give away for participants in these proactive programs.

Last year, we have been introducing a global safety program in our company. Our goal with the application of this program is to reduce by 25 % our recordable incident rate over the next 5 years.

Although not a "safety initiative" focus on and commitment to safety by Senior Mgmt has been impactful

Accountability, Health/Wellness

Accountability, Health/Wellness

Have implemented some stretching routines to help reduce exertion injuries

Formal safety program with support from CEO. Safety training, bonuses etc.

We have 5 & 10 meetings on a weekly basis, monthly safety meetings. Detailed safety improvement plan for the organization. Weekly

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11| SAFETY-RELATED INITIATIVES SUCCESSFUL IN REDUCING INJURIES FOR PERSONNEL OFFICE

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q11.2

Response

Recognize individual participation in safety through Culture Change, Focus Team, Safety Training Camp,and Light Pow er and Pride initiatives. Employees that volunteer to get involved in safety are recognized w ith shirts, jackets, and mugs. Light Pow er and Pride offers a monetary recognition gift. Extending safety recognition to people w ho put in safety suggestions, reconize w ork place hadzards and report near misses. There w ill be a monthly give aw ay for participants in these proactive programs.

Same answ er

Accountability, Health/Wellness

Accountability, Health/Wellness

Ergonomic assessments of w ork stations

Safety committee formed. Training, bonuses etc.

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12| WHAT WELLNESS [PHYSICAL AND MENTAL] INITIATIVES OR CULTURAL CHANGES HAVE BEEN SUCCESSFUL IN REDUCING ILLNESSES FOR PERSONNEL? INCLUDE DATE OF INCEPTION.

	Responses	Comments
Total Participants	18	
Number of Respondants	11	

Calculation used

Q12.1

Response

We have had the Health Enhancement Initiative (since 1997) which offers programs on nutrition, physical fitness, stress management (etc.). They also work with Food Service for healthier options in cafe/vending, alignment of preventive health benefits, and support safety programs like stretching/back programs as needed. Success has been demonstrated relative to participation and health care expenditure trends.

Data not available - Advertisement & reminders of available resources are more common.

Wellness program for employees - not sure of date.

Do not have Wellness program, but have bugeted money for the 2009-2010 calender year for a new initiative which includes onsite "wellness coaching". Also we bugeted for blood pressure machines and the new excercise equipment.

Last year, we have been introducing a global safety program in our company. Our goal with the application of this program is to reduce by 25 % our recordable incident rate over the next 5 years.

Nothing New - but historic commitment to personal lifestyle and more current corporate focus on safety both continue to have influence

Health and Wellness program (2007). Post offer, pre-placement fitness testing (2008)

Health and Wellness program (2007) Post offer, pre placement fit test (2008)

We are just beginning to look at the areas of health and wellness and will develop programs in the near future.

Stretching program / industrial athlete training program / nurse available for on an off the job injuries

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13| CORPORATE GOAL REGARDING CHANGES TO SAFETY

	Responses	Comments
Total Participants	18	
Number of Respondants	12	

Calculation used

Q13.1

Response

We aim for zero injuries and are evaluating our company culture's impact on safety. Leadership safety training; Risk Assessment; Behavior Based Safety are key areas.

Management & safety committees meet monthly to partner for safety actions that promote safe behavior.

No compromise, safety #1 priority.

Goal of reaching industry average in injury rates which will position organization to pursue "world class" safety designation through OSHA's 15% redution in injuries. Currently have a 38% reduction over 2007 year to date.

Improve our statistics

Corporate target 0.5 AIF and <10 Severity by 2025, current focus on serious injury, hazard ID and risk reduction, control enhancement (safety by design)

Leading indicators for goals including training, attending safety meetings, and others.

We have leading indicators for goals, that would include training, attending safety meetings, and others.

We put safety first; We focus on preventing injuries; We work safely and efficiently all the time; We have high standards for public safety; We ensure that employees understand their responsibilities through the Health, Safety & Environment Management System;

We are committed to providing a safe workplace for all of our employees and contractors. We believe that safety is an attitude.

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Provide a w ork place free from hazards. Management pay and bonus is based on safety performance. Our goal is to be in the top 10% of a designated peer group. Pursuing a single organizational behavioral safety program.

A corporate level peer team (Incident Free Culture Committee) has been established to monitor and make recommendations on all aspectes of safety performance.

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Staffing & Outsourcing

T&D Staffing: FTEs per 100,000 Customers
Distribution Staffing: FTEs per 100,000 Customers
Distribution Staffing: FTEs per 100,000 Customers by Staffing Category
1| Wage Rate: Distribution Journey Level Line Worker
1| Wage Rate: Distribution Engineering Entry Level
1| Wage Rate: Substation Entry Level Engineer
1| Wage Rate: Substation Journey Level Electrician
1| Wage Rate: Transmission Entry Level Engineer
1| Wage Rate: Transmission Journey Level Line Worker
5| Percent of staffing group represented by a union/bargaining unit: Distribution Field
5| Percent of staffing group represented by a union/bargaining unit: Distribution Engineering
5| Percent of staffing group represented by a union/bargaining unit: Substation Electrician
5| Percent of staffing group represented by a union/bargaining unit: Substation Engineering
5| Percent of staffing group represented by a union/bargaining unit: Transmission Field
5| Percent of staffing group represented by a union/bargaining unit: Transmission Engineering
6| Initiatives underway to manage the changes in your workforce: Changing work attitudes
6| Initiatives underway to manage the changes in your workforce: Recruiting
6| Initiatives underway to manage the changes in your workforce: Retention
6| Initiatives underway to manage the changes in your workforce: Retirements
Outsourcing Percentages: Distribution
Outsourcing Percentages: Substation
Outsourcing Percentages: Transmission

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8| Recent changes made in amount of contracting Engineering

8| Recent changes made in amount of contracting Field Construction

8| Recent changes made in amount of contracting Field Maintenance

8| Recent changes made in amount of contracting Other

8| Recent changes made in amount of contracting Trouble Response

8| Recent changes made in amount of contracting Vegetation Management

9| Describe any recent changes made in types of work contracted.

10| Describe any recent changes made in contracting policies.

11| Describe any approaches that have made outsourcing a successful decision for you.

12| Describe any approaches that have been successful for pooling or sharing resources [separate from outsourcing].11| Describe any approaches that have made outsourcing a successful decision for you.

13| What initiatives do you have underway to improve contracting management?

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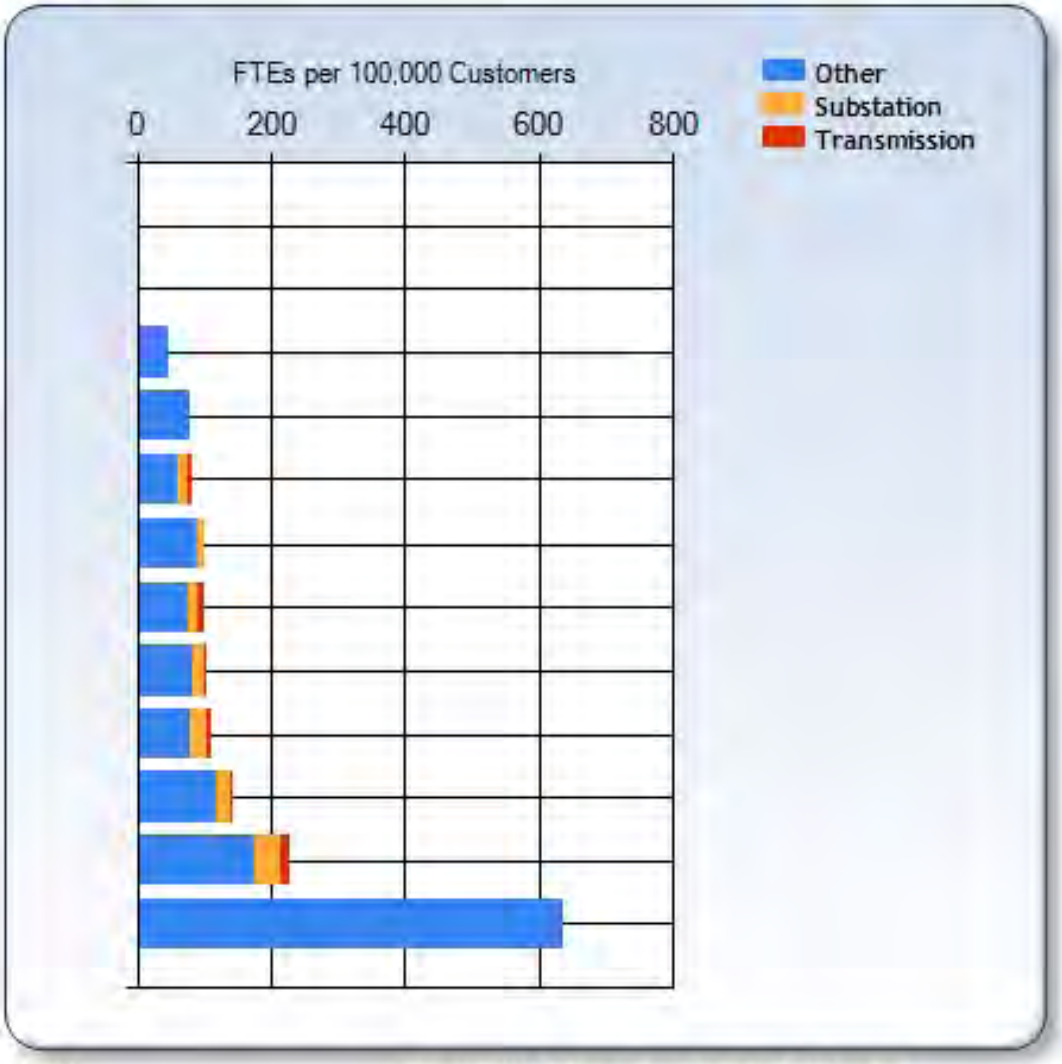
T&D STAFFING: FTES PER 100,000 CUSTOMERS



Mean Quartile	
Mean	137
Quartile 1	72
Quartile 2:	102
Quartile 3:	119

Comments

Calculation used

(Distribution FTEs) / ((T&D Dist End Use Customers) / 100000), (Substation FTEs) / ((T&D Dist End Use Customers) / 100000), (Transmission FTEs) / ((T&D Dist End Use Customers) / 100000)

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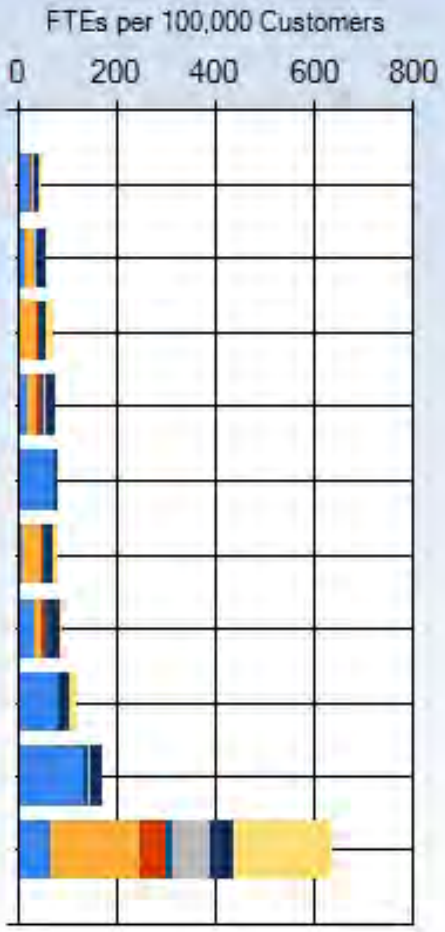
DISTRIBUTION STAFFING: FTES PER 100,000 CUSTOMERS



Field Construction
Field Maintenance
Trouble Response
Dispatch
Vegetation Management
Engineering and Design
Other

Mean Quartile	
Mean	145
Quartile 1	76
Quartile 2:	83
Quartile 3:	112

Comments

Calculation used

(Q2.1A + Q2.1B + Q2.1C + Q2.1D) / ((T&D Dist End Use Customers) / 100000), (Q2.2A + Q2.2B + Q2.2C + Q2.2D) / ((T&D Dist End Use Customers) / 100000), (Q2.3A + Q2.3B + Q2.3C + Q2.3D) / ((T&D Dist End Use Customers) / 100000), (Q2.4A + Q2.4B + Q2.4C + Q2.4D) / ((T&D Dist End Use Customers) / 100000), (Q2.5A + Q2.5B + Q2.5C + Q2.5D) / ((T&D Dist End Use Customers) / 100000), (Q2.6A + Q2.6B + Q2.6C +

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DISTRIBUTION STAFFING: FTES PER 100,000 CUSTOMERS BY STAFFING CATEGORY



Mean Quartile	
Mean	145
Quartile 1	76
Quartile 2:	83
Quartile 3:	112

Comments

Calculation used

(Q2.1A + Q2.2A + Q2.3A + Q2.4A + Q2.5A + Q2.6A + Q2.7A) / ((T&D Dist End Use Customers) / 100000), (Q2.1B + Q2.2B + Q2.3B + Q2.4B + Q2.5B + Q2.6B + Q2.7B) / ((T&D Dist End Use Customers) / 100000), (Q2.1D + Q2.2D + Q2.3D + Q2.4D + Q2.5D + Q2.6D + Q2.7D) / ((T&D Dist End Use Customers) / 100000), (Q2.1C + Q2.2C + Q2.3C + Q2.4C + Q2.5C + Q2.6C + Q2.7C) / ((T&D Dist End Use Customers) / 100000)

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1| WAGE RATE: DISTRIBUTION JOURNEY LEVEL LINE WORKER



Mean Quartile	
Mean	$32.28
Quartile 1	$29.58
Quartile 2:	$32.47
Quartile 3:	$34.75

Comments

Calculation used

Q1.5

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1| WAGE RATE: DISTRIBUTION ENGINEERING ENTRY LEVEL



Mean Quartile	
Mean	$30.45
Quartile 1	$26.09
Quartile 2:	$27.62
Quartile 3:	$34.55

Comments

Calculation used

Q1.6

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FIRST QUARTILE CONSULTING

1| WAGE RATE: SUBSTATION ENTRY LEVEL ENGINEER



Mean Quartile	
Mean	$30.26
Quartile 1	$27.48
Quartile 2:	$27.88
Quartile 3:	$32.66

Comments

Calculation used

Q1.4

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1| WAGE RATE: SUBSTATION JOURNEY LEVEL ELECTRICIAN



Mean Quartile	
Mean	$33.19
Quartile 1	$31.12
Quartile 2:	$33.72
Quartile 3:	$35.94

Comments

Calculation used

Q1.3

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1| WAGE RATE: TRANSMISSION ENTRY LEVEL ENGINEER



Mean Quartile	
Mean	$31.15
Quartile 1	$27.48
Quartile 2:	$27.88
Quartile 3:	$35.17

Comments

Calculation used

Q1.2

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1| WAGE RATE: TRANSMISSION JOURNEY LEVEL LINE WORKER



Mean Quartile	
Mean	$32.49
Quartile 1	$28.85
Quartile 2:	$33.74
Quartile 3:	$33.80

Comments

Calculation used

Q1.1

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FIRST QUARTILE CONSULTING

5| PERCENT OF STAFFING GROUP REPRESENTED BY A UNION/BARGAINING UNIT: DISTRIBUTION FIELD



Mean Quartile	
Mean	87 %
Quartile 1	94 %
Quartile 2:	100 %
Quartile 3:	100 %

Comments

Calculation used

Q5.1

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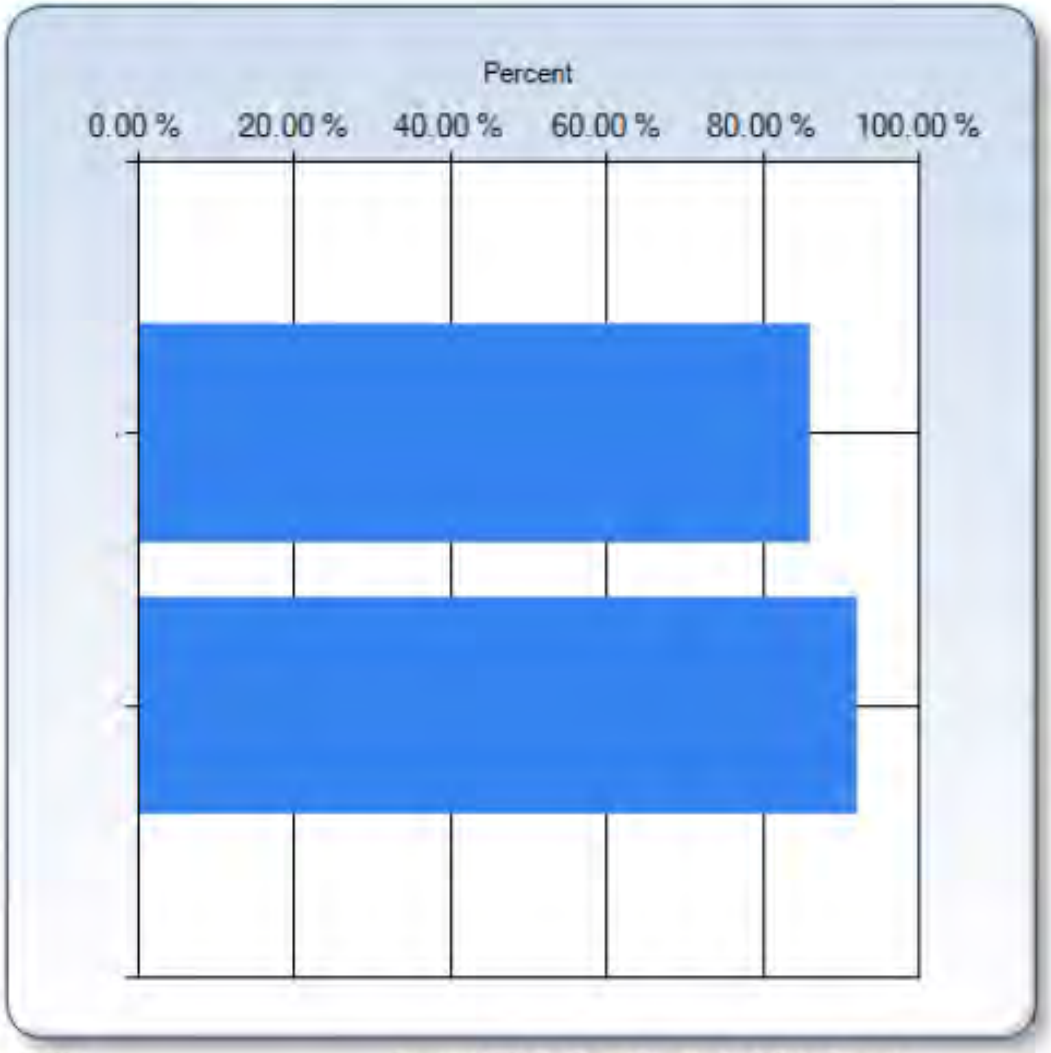
FIRST QUARTILE CONSULTING

5| PERCENT OF STAFFING GROUP REPRESENTED BY A UNION/BARGAINING UNIT: DISTRIBUTION ENGINEERING



Mean Quartile	
Mean	89.00 %
Quartile 1	87.50 %
Quartile 2:	89.00 %
Quartile 3:	90.50 %

Comments

Calculation used

Q5.2

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FIRST QUARTILE CONSULTING

5| PERCENT OF STAFFING GROUP REPRESENTED BY A UNION/BARGAINING UNIT: SUBSTATION ELECTRICIAN



Mean Quartile	
Mean	88 %
Quartile 1	100 %
Quartile 2:	100 %
Quartile 3:	100 %

Comments

Calculation used

Q5.3

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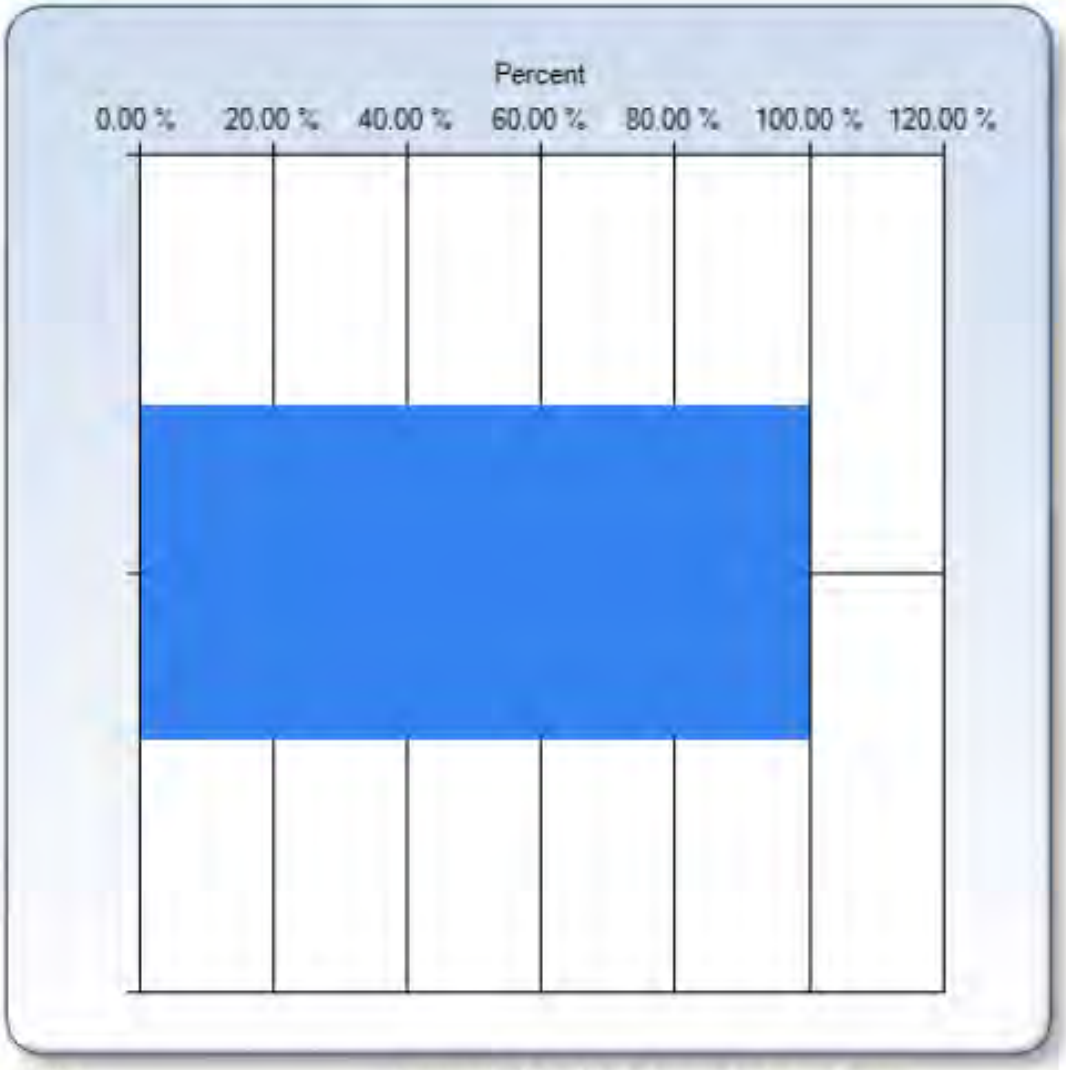
5| PERCENT OF STAFFING GROUP REPRESENTED BY A UNION/BARGAINING UNIT: SUBSTATION ENGINEERING



Mean Quartile	
Mean	100.00 %
Quartile 1	100.00 %
Quartile 2:	100.00 %
Quartile 3:	100.00 %

Comments

Calculation used

Q5.4

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FIRST QUARTILE CONSULTING

5| PERCENT OF STAFFING GROUP REPRESENTED BY A UNION/BARGAINING UNIT: TRANSMISSION FIELD



Mean Quartile	
Mean	84 %
Quartile 1	100 %
Quartile 2:	100 %
Quartile 3:	100 %

Comments

Calculation used

Q5.5

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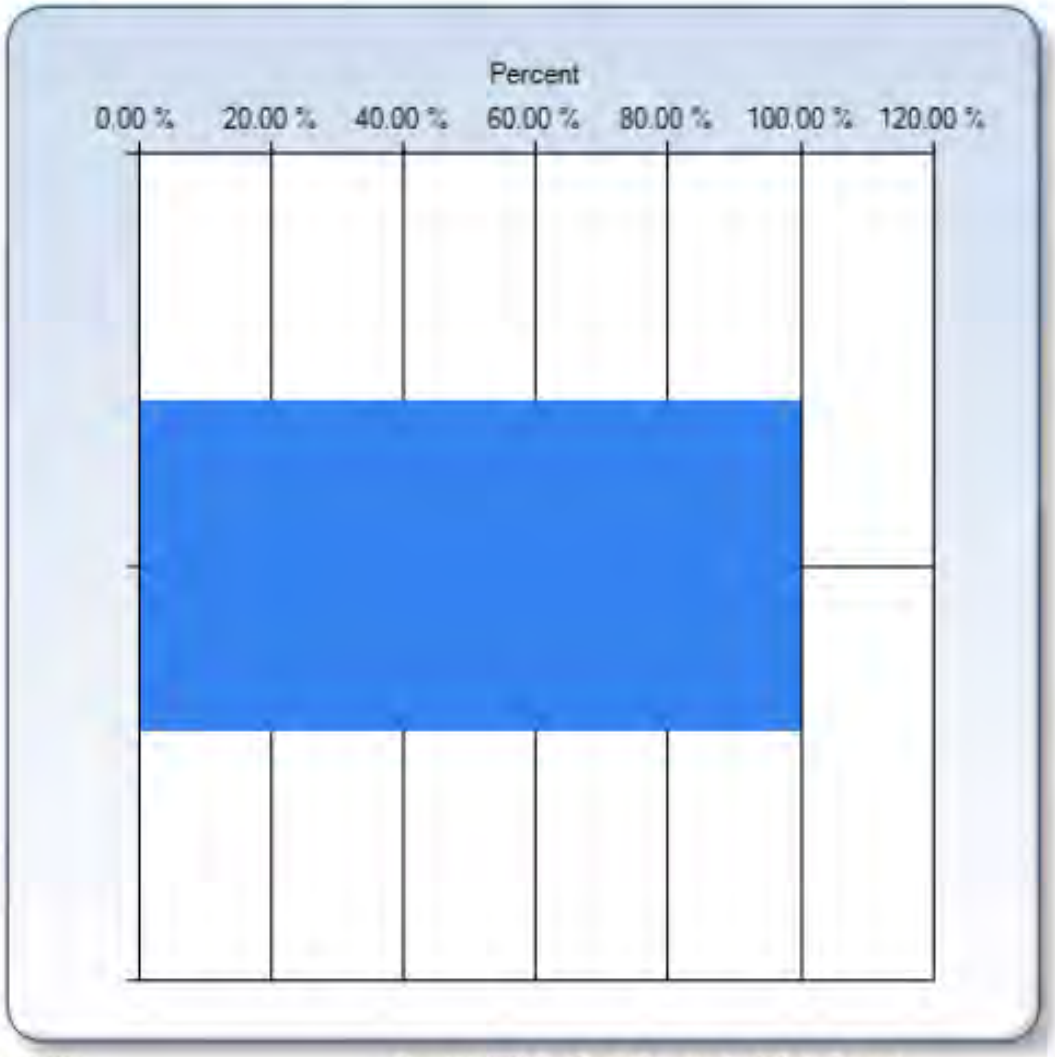
5| PERCENT OF STAFFING GROUP REPRESENTED BY A UNION/BARGAINING UNIT: TRANSMISSION ENGINEERING



Mean Quartile	
Mean	100.00 %
Quartile 1	100.00 %
Quartile 2:	100.00 %
Quartile 3:	100.00 %

Comments

Calculation used

Q5.6

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6| INITIATIVES UNDERWAY TO MANAGE THE CHANGES IN YOUR WORKFORCE: CHANGING WORK ATTITUDES

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q6.5

Response

Providing our supervisors various "meeting in a box" presentations to aid in change management.

Considering flex hours & flex schedules. Field personnel are encouraged to pursue education to allow them to be qualified for other positions. This could be external, formal education or by taking advantage of CNP University. CNP University is a Intranet tool that allows employees to take interactive classes in time management, 'people' skills, etc. and lends self help books, videos, & CDs. These can be ordered on line & sent to the employee via company mail.

Employee Engagement

Looking at changing demographics, no changes implemented yet.

Conducting employee engagement survey this year to assess whats working/where changes are needed in our workforce retention an engagement strategies

Designating career paths for employees

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6| INITIATIVES UNDERWAY TO MANAGE THE CHANGES IN YOUR WORKFORCE: RECRUITING

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q6.3

Response

Better outreach to colleges to recruit new engineering talent and to various workforce development agencies and community groups to recruit a diverse pool of qualified candidates for line mechanic apprentice and other entry level field positions.

Continuously recruiting people with experience, as well as those new to the workforce

A key focus because many field positions are vacant

Ongoing

Working with colleges to develop and recruit future employees.

Significantly increased Apprentice, Technical Trainee and University Graduate hiring, Hiring of Foreign-Trained Professionals through Career Bridge,All time high levels of Co-Op/Intern/Fellowship hiring for students

Hiring more entry-level candidates due to difficulty recruiting experienced candidates.

Data analysis of reseach on what attracts/retains employees to compare against current state. Targeted advertising for critical positions Designating career paths for employees Implement career awareness curriculum to high schools. A pilot has been conducted and curriculum being revised based on feedback. Creating career awareness video

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6| INITIATIVES UNDERWAY TO MANAGE THE CHANGES IN YOUR WORKFORCE: RETENTION

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q6.1

Response

Ensuring that our pay and benefits remain competitive, particularly for engineers.

Individual performance & development plans. Considering plan to bring back retirees to work part time without detriment to retirement benefits.

Employee mentoring and conducting salary analysis.

Mentoring Program. Accelerated Development opportunities for High-Potential Employees

Data analysis of reseach on what attracts/retains employees to compare against current state. Revised relocation policy to address loss of sale on homes

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6| INITIATIVES UNDERWAY TO MANAGE THE CHANGES IN YOUR WORKFORCE: RETIREMENTS

	Responses	Comments
Total Participants	18	
Number of Respondants	5	

Calculation used

Q6.2

Response

Taking advantage of current "retirement bubble" to decide whether we should downsize our own line construction and operations workforce. We will outsource more work if viable cost-effective contracting options are available but will also give our unions a chance to make changes that would make their workforce more competitive. Have firm plans now to allow retirements to downsize our design workforce while we implement new processes and tehnology that will improve efficiency; We are hiring into key engineering and management development positions ahead of anticipated retirements to allow effective knowledge transfer.

Succession plans for key positions. Distributing the work of retiree among existing employees to defer hiring a new employee when practical.

None

No changes as yet

Pre-hiring in anticipation of retirements

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OUTSOURCING PERCENTAGES: DISTRIBUTION

Total Respondents	6
Field Construction	46
Field Maintenance	25
Trouble Response	16.33
Vegetation Management	99.17
Engineering	5.4

Comments

Calculation used

Q7.1A, Q7.2A, Q7.3A, Q7.4A, Q7.5A

Legends						
Field Construction	80 %	15 %		35 %	70 %	30 %
Field Maintenance	30 %	5 %		20 %	60 %	10 %
Trouble Response	45 %	5 %	0 %	3 %	15 %	30 %
Vegetation Management	100 %	100 %	100 %	100 %	100 %	95 %
Engineering	10 %	0 %	5 %		2 %	10 %

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OUTSOURCING PERCENTAGES: SUBSTATION

Total Respondents	7
Field Construction	80.43
Field Maintenance	31.14
Trouble Response	30.71
Vegetation Management	80.83
Engineering	39.29

Comments

Calculation used

Q7.1B, Q7.2B, Q7.3B, Q7.4B, Q7.5B

Legends							
Field Construction	99 %	90 %	100 %	30 %	80 %	99 %	65 %
Field Maintenance	99 %	5 %	0 %	15 %	0 %	99 %	0 %
Trouble Response	100 %	5 %	0 %	0 %	0 %	100 %	10 %
Vegetation Management	95 %	100 %	100 %		95 %	95 %	0 %
Engineering	75 %	35 %	5 %	5 %	10 %	75 %	70 %

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OUTSOURCING PERCENTAGES: TRANSMISSION

Total Respondents	7
Field Construction	87.57
Field Maintenance	56.33
Trouble Response	52.5
Vegetation Management	95.83
Engineering	48.57

Comments

Calculation used

Q7.1C, Q7.2C, Q7.3C, Q7.4C, Q7.5C

Legends							
Field Construction	99 %	90 %	90 %	100 %	95 %	99 %	40 %
Field Maintenance	99 %	60 %	50 %		30 %	99 %	0 %
Trouble Response	100 %	75 %	0 %		30 %	100 %	10 %
Vegetation Management	95 %	100 %	90 %		95 %	95 %	100 %
Engineering	75 %	40 %	5 %	85 %	10 %	75 %	50 %

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8| RECENT CHANGES MADE IN AMOUNT OF CONTRACTING ENGINEERING

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q8.5

Response
No recent changes
2 design engineers brought in
Beginning to move up due to vacancies
NA
none
none
50-60% of all the engineering is contracted.

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8| RECENT CHANGES MADE IN AMOUNT OF CONTRACTING FIELD CONSTRUCTION

	Responses	Comments
Total Participants	18	
Number of Respondants	9	

Calculation used

Q8.1

Response

Moved most street light installation work to a contractor. We are now working with the same contractor to outource street light underground fault location and repairs as one package. Also outsourced a special program to provide electric services to ATT boxes being installed on an accelerated schedule to roll-out their "ATT Universal" service (competition to Cable TV).

We are contracting for the first time on 30 years

More outsourcing because of the increasing number of retirements

Amount of contracting is dependant upon overall work loads.

NA

none

none

No change in practice - Resources change with workloads

All grading work was assigned to internal construction.

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8| RECENT CHANGES MADE IN AMOUNT OF CONTRACTING FIELD MAINTENANCE

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q8.2

Response
Increased contracting of pole replacement work (program maintenance). We have contracted pole inspection and treatment/reinforcement work for 10+ years
up
Amount of contracting is dependant upon overall work loads.
NA
none
none
No change in practice - Resources change with workloads

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8| RECENT CHANGES MADE IN AMOUNT OF CONTRACTING OTHER

	Responses	Comments
Total Participants	18	
Number of Respondants	3	

Calculation used

Q8.6

Response
NA
none
none

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8| RECENT CHANGES MADE IN AMOUNT OF CONTRACTING TROUBLE RESPONSE

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q8.3

Response
Using on site overhead contract crew s more frequently in a trouble response role during w eather events
Covered w ith mutual aid agreements w ith other utilities
NA
none
none
Storm restoration mainly
Emergent w ork is typically done by internal const. forces.

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8| RECENT CHANGES MADE IN AMOUNT OF CONTRACTING VEGETATION MANAGEMENT

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q8.4

Response
No recent changes
Renew ed 4-yr contract w ith tree trimming firm
NA
none
none
No change since the mid 90s

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9| DESCRIBE ANY RECENT CHANGES MADE IN TYPES OF WORK CONTRACTED.

	Responses	Comments
Total Participants	18	
Number of Respondants	10	

Calculation used

Q9.1

Response

Moved most street light installation work to a contractor. We are now working with the same contractor to outsource street light underground fault location and repairs as one package. Also outsourced a special program to provide electric services to ATT boxes being installed on an accelerated schedule to roll-out their "ATT Universal" service (competition to Cable TV).

Engineering design contracted for the first time

Focus on high voltage electrical construction

More outsourcing because of the increasing number of retirements

Pulling and splicing of plastic feeder work.

Since 2005 we have outsourced additional construction, maintenance, civil and underground, and estimating work.

NA

none

Types have remained constant. Percent contracted will vary with workload

Grading work is now being done exclusively by internal construction forces.

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10| DESCRIBE ANY RECENT CHANGES MADE IN CONTRACTING POLICIES.

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q10.1

Response

Policy now is to identify and evaluate contracting options before considering replacement of company staff. In the past our policy in most areas including overhead line work was to contract only large projects plus "peak shaving" when we were falling behind on due dates for more routine work.

Increase amount of work contracted

Our contracting philosophy has migrated to more firm bid and unit pricing of capital and maintenance work.

NA

Continued administrative notification requirements. More unit and firm bidding.

All jobs over a certain size are awarded by sealed bid or reverse auction.

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11| DESCRIBE ANY APPROACHES THAT HAVE MADE OUTSOURCING A SUCCESSFUL DECISION FOR YOU.

	Responses	Comments
Total Participants	18	
Number of Respondants	6	

Calculation used

Q11.1

Response

Competitive bidding of larger projects using electronic reverse auctions - we have achieved signficant "discounts" when the market is right and have never needed to accept bids that exceeded our internal cost estimate for the work.

Significant executive support

Multi year service agreements with multiple contractors in a geographic area. Flexibility is key to success.

NA

Continue to use contracting as peaking service. More unit and firm bid pricing

Competition between Partners has made outsourcing more cost competetive.

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12| DESCRIBE ANY APPROACHES THAT HAVE BEEN SUCCESSFUL FOR POOLING OR SHARING RESOURCES [SEPARATE FROM OUTSOURCING].11| DESCRIBE ANY APPROACHES THAT HAVE MADE OUTSOURCING A SUCCESSFUL DECISION FOR YOU.

	Responses	Comments
Total Participants	18	
Number of Respondants	7	

Calculation used

Q12.1

ID	Response
	Central scheduling and resource allocation for all company line construction crews. We regularly move work and/or crews between company service center locations to levelize workloads. We are now developing plans to expand this proceess to encompass designers.
	Coordination of internal joint trenching for gas and electric along with coordination of joint trenching with phone & cable whenever practically possible
	Mutual aid during emergencies
	Centralization of emergency centre during major event managing resources to best restore power
	NA
	Past success in traveling company personnel when resources available.
	On a regular basis equipment is shared among different construction groups on site.

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13| WHAT INITIATIVES DO YOU HAVE UNDERWAY TO IMPROVE CONTRACTING MANAGEMENT?

	Responses	Comments
Total Participants	18	
Number of Respondants	8	

Calculation used

Q13.1

Response

Combined gas and electric blanket contracts were implemented last year for underground work. We are now hiring and shifting supervisors into a central contractor management group within our business unit to perform quality inspections of both gas and electric work and audit the pay paperwork. In the past these duties were handled by a multitide of field supervisors and separately for gas and electric work at the same locations. This new arrangement should improve consistency, reduce redundant job site trips and better manage contracting costs.

Currently in discussions with our contractors to determine the feasibility of an Alliance rather than a simple contractor arrangement

New construction management office, increased staff to contract and manage projects

Rollout of Indus Suite scheduling tool

We are moving towards an improved inspection program to further verify quality of work and conformance to standards.

NA

More field audits and documentation of audits

Quarterly evaluations to review schedule, cost, and quality.

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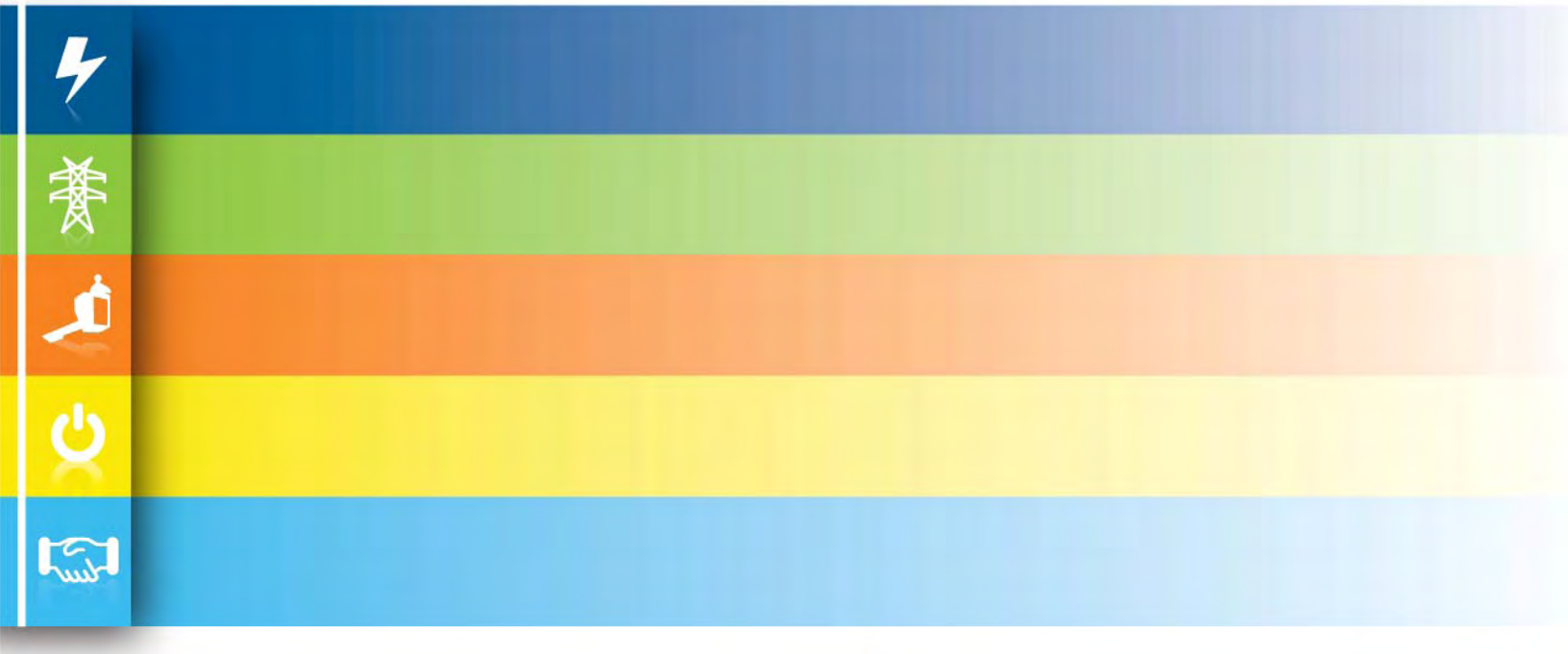
2008

ANNUAL SERVICE CONTINUITY REPORT ON DISTRIBUTION SYSTEM PERFORMANCE IN ELECTRICAL UTILITIES

Composite Version



2008

ANNUAL SERVICE CONTINUITY REPORT ON DISTRIBUTION SYSTEM PERFORMANCE IN ELECTRICAL UTILITIES

Composite Version

June 2009

Canadian Electricity Association
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INTRODUCTION

This report presents the results of the forty-seventh consecutive survey of the performance of the Distribution Systems in electrical utilities. The report, prepared by the Canadian Electricity Association (CEA), presents a statistical summary of the Distribution Systems Performance for the year 2008 and compares it to 2007, as well as to the 2004-2008 five-year average.

The report presents some industry standard metrics for the Electricity Distribution including:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Frequency Index (Momentary) (SAIFI-MI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)
- Index of Reliability (IOR)

By using the above metrics in combination with the cause of an electricity interruption, utility companies can

- set targets for improvement
- develop programs in support of their improvement targets
- make design/build decisions that try to mitigate interruption causes

Members of the Service Continuity Committee and participants in the Service Continuity program follow a systematic procedure for collecting and analyzing data with regard to the Distribution System Performance according to definitions set by the Committee. This procedure follows the guidelines set out by CEA's Electric Power System Reliability Assessment program (EPSRA) which governs system continuity statistics for the entire electricity system. This includes the statistics captured in this report for the Distribution system and also statistics captured in the Bulk Electric System (BES) for service interruptions within the Transmission system. The EPSRA program is governed by the Consultative Committee on Outage Statistics (CCOS). The CCOS Committee is chaired by Dr. Roy Billinton of the University of Saskatchewan, a world renowned expert in the field of Electricity Equipment and Systems Reliability. The mission and vision of the Service Continuity Committee is below:

Mission:

Provide a comprehensive database of component and system reliability and performance data which will assist member utilities in the optimal utilization of corporate and financial resources.

Vision:

To be recognized as a world-class reliability database which meets the needs of its member utilities.

At the recommendation of the program participants, CCOS approved the creation of the Service Continuity Committee (SCC) in 2003. The objectives of the SCC are:

- To add value to SCC members by providing a forum for Distribution System personnel to identify, develop and monitor the relevancy of key performance indicators and actively seek ones that provide a perspective on the continuity of electric supply to the customer
- To facilitate development of inter-utility networking for Distribution System reliability
- To maintain, update and provide guidance on common definitions and terms used in service continuity performance measurement consistent with Canadian and international utility practices
- Provide guidance with respect to maintaining data integrity
- Reporting to CEA's Consultative Committee on Outage Statistics (CCOS) and supporting its overall mandate of providing its members with relevant comparative reliability information together with a network of contacts to enhance performance
- Coordinate with other CEA groups such as the Committee on Performance Excellence (COPE) and the Distribution and Customer Councils

The membership of SCC includes one member of each of the participating CEA Corporate member utilities. It is Chaired by Kevin Billay of ATCO Electric, the Vice-chair is Margaret DeFazio of Hydro Ottawa and the Past Chair is Blair Howell of ATCO Electric.

ACKNOWLEDGEMENT

We wish to thank the Consultative Committee on Outage Statistics (CCOS) and, in particular, its Chair, Dr. Roy Billinton, for their support and guidance.

We wish to thank the utilities that have contributed data for this report. They are:

ATCO Electric
B.C. Hydro
BELCO (Bermuda)
Brookfield Power (Great Lakes Power)
City of Medicine Hat
City of Red Deer
CLP Power Hong Kong Limited
Enersource Hydro Mississauga
ENMAX Power Corporation
EPCOR
FortisAlberta
FortisBC
Horizon Utilities
Hydro One
Hydro Ottawa
Hydro-Sherbrooke
Manitoba Hydro
Maritime Electric Company
New Brunswick Power
Newfoundland & Labrador Hydro
Newfoundland Power
Nova Scotia Power Inc.
PowerStream Inc.
Saskatoon Light & Power
SaskPower
St. Lucia Electricity Services
St. Thomas Energy
Toronto Hydro
Trinidad & Tobago Electricity Commission
Veridian Connections

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1.0 DEFINITIONS

1.0 DEFINITIONS

1.1 DEFINITION OF TERMS

DISTRIBUTION SYSTEM

A Distribution System is that portion of an electric power system which links the Bulk Electricity System (BES) or sources with the customer's facilities.

Subtransmission lines, distribution substations, primary feeders, distribution transformers, secondaries and customer's services all form different parts of what can generally be called Distribution Systems. The Delivery Point (DP) is the delineation point between the BES and the Distribution System. It is the low voltage busbar of the step down transformer station, whereby the transformer busbar is considered part of the BES System. At the transformer station the voltage is stepped down from a transmission voltage, which may cover a range of 60-750kV to a distribution voltage of under 60kV.

Where the reporting company does not own the equipment up to the Delivery Point as defined above, the delineation point shall be at the point of ownership.

CUSTOMERS

The average number of customers served in the region during the reporting period. This means the number of customer services fed at secondary, primary and subtransmission voltages. A customer is defined as a metered service. Municipal utilities buying power from Provincial utilities should not be reported as customers by the Provincial utility.

INTERRUPTION

An *interruption* is the loss of service to one or more customers and is the result of one or more component outages. A *momentary interruption* is defined as an interruption with a duration of less than one (1) minute. These are interruptions generally restored by automatic reclosure facilities, which are of a very short duration (of the order of a few seconds).

INTERRUPTION-DURATION

This is the period from the initiation of an interruption to a customer until service has been restored to that customer.

CUSTOMER-HOURS OF INTERRUPTION

This is the product of the customer services interrupted by the period of interruption.

CUSTOMER-INTERRUPTIONS

This is the sum of products of the customer services interrupted by the number of interruptions that affect those customer services.

SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (SAIFI)

This index is defined as the average number of interruptions per customer served per year.

$$\textbf{SAIFI} = \frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$$

SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX (MOMENTARY) SAIFI (MI)

This index is defined as the average number of interruptions per customer served per year for momentary interruptions (interruptions of a duration less than 1 minute).

$$\textbf{SAIFI (MI)} = \frac{\text{Total Momentary Customer-Interruptions}}{\text{Total Customers Served (in area where momentary interruptions are monitored)}}$$

SYSTEM AVERAGE INTERRUPTION DURATION INDEX (SAIDI)

This index is defined as the system average interruption duration for customers served per year.

$$\textbf{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

CUSTOMER AVERAGE INTERRUPTION DURATION INDEX (CAIDI)

This index is defined as the customer average interruption duration for customers interrupted during a year.

$$\textbf{CAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

INDEX OF RELIABILITY

The per unit of annual customer-hours that service is available.

$$\textbf{Index of Reliability} = \frac{\text{8,760 hours/year - SAIDI}}{\text{8,760 hours/year}}$$

1.2 CLASSIFICATION OF INTERRUPTIONS BY CAUSE

A customer interruption has been defined in terms of primary cause of the interruption. These causes have been assigned the following codes:

0 - *Unknown/Other*

Customer interruptions with no apparent cause or reason which could have contributed to the outage.

1 - *Scheduled Outage*

Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

2 - *Loss of Supply*

Customer interruptions due to problems in the bulk electricity supply system such as underfrequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.

3 - *Tree Contacts*

Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

4 - *Lightning*

Customer interruptions due to lightning striking the Distribution System, resulting in an insulation breakdown and/or flashovers.

5 - *Defective Equipment*

Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

6 - *Adverse Weather*

Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

7 - *Adverse Environment*

Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

8 - *Human Element*

Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage, or sabotage.

9 - *Foreign Interference*

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.

QUARTILE GRAPHS

This year, for the first time, the 2008 Service Continuity Report will include a number of quartile graphs, which can be found in sections 6 and 7.

Explanation of Quartile Graphs

To understand the quartiles, one needs to understand percentiles (or quantiles) as the quartile calculation depends on the percentiles definition. The First quartile is the 25th percentile (noted 1st quartile), the Median value is the 50th percentile (2nd quartile), and the Third quartile is the 75th percentile. A percentile is a value at or below which a given percentage or fraction of the variable values lie. For a set of measurements arranged in order of magnitude, the p-th percentile is the value that has p% of the measurements below it and (100-p)% above it. Thus, the 25th percentile (or 1st quartile) is the value such that one quarter of the data lie below it.

2.0 PERFORMANCE OF UTILITIES

2.0 PERFORMANCE OF UTILITIES

2.1 COMPARISON OF 2008 CANADIAN SYSTEM INDICES TO 2007

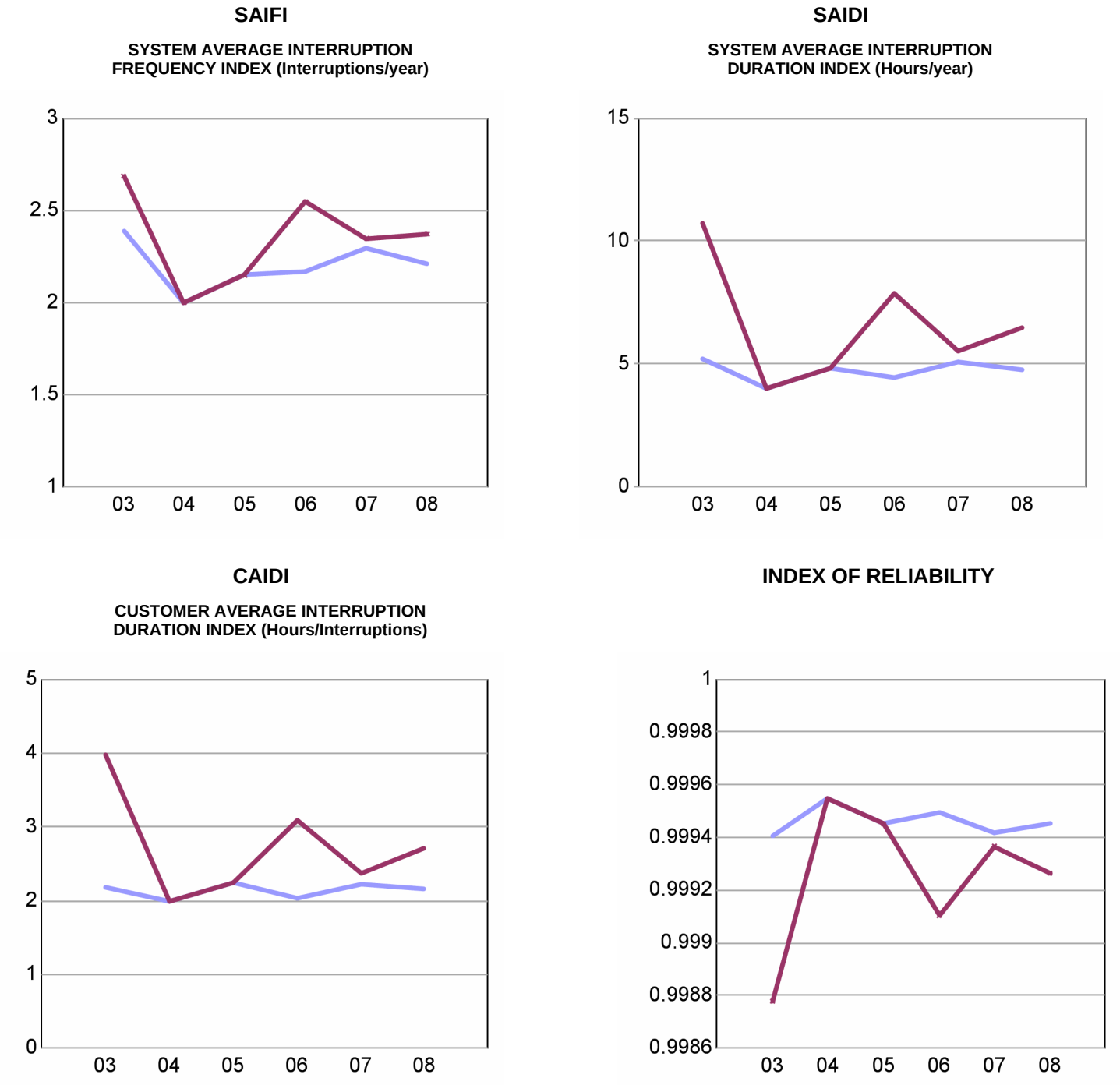
SAIFI The average number of interruptions per customer per year was 2.34, which represents an increase of 0.9% over the 2007 figure of 2.32.

SAIDI The system average interruption duration for customers served was 6.29 hours per year, which represents an increase of 13.0% over the 2007 figure of 5.47 hours.

CAIDI The average customer interruption duration per interruption was 2.69 hours, which represents an increase of 12.2% over the 2007 figure of 2.36 hours.

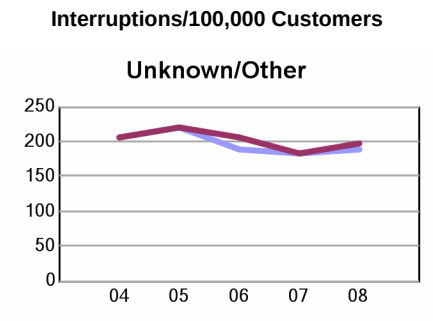
Index of Reliability or the per unit annual customer hours that service is available was 0.999282, as compared to 0.999376 in 2007.

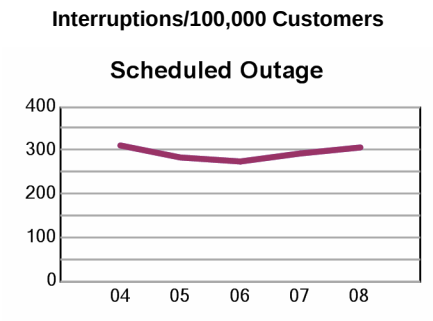
The annual variations in the service indices of SAIFI, SAIDI, CAIDI and the INDEX OF RELIABILITY for Canadian data for the period 2003 to 2008 are shown below in Graph 2.1.

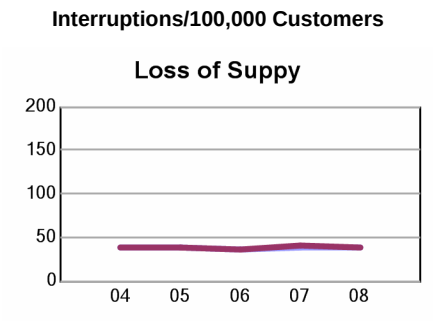


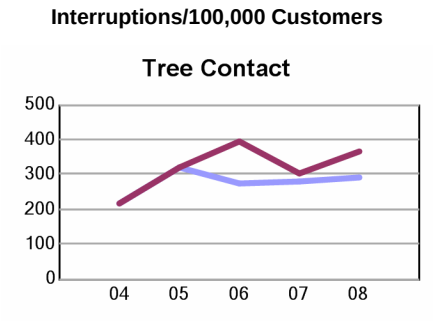
Note: ——— denotes the exclusion of Significant Event data (see Appendix E).

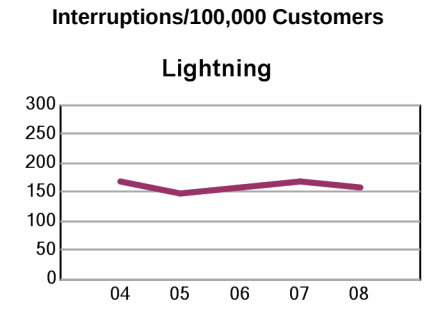
Graph 2-1 System Indices of SAIFI, SAIDI, CAIDI & IOR for 2003-2008 Canadian Data

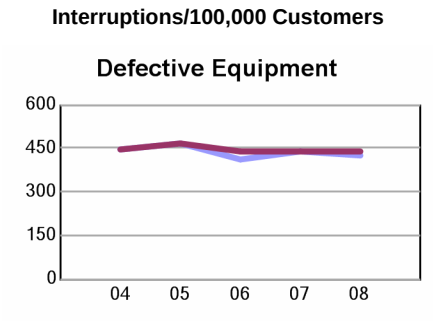


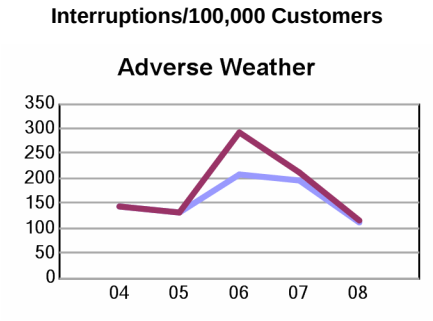


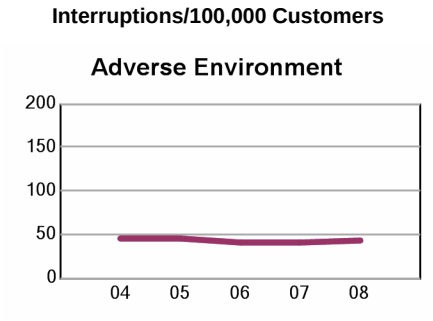


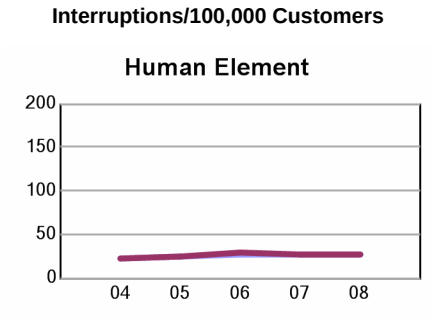


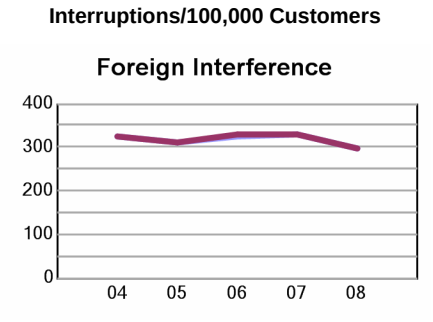


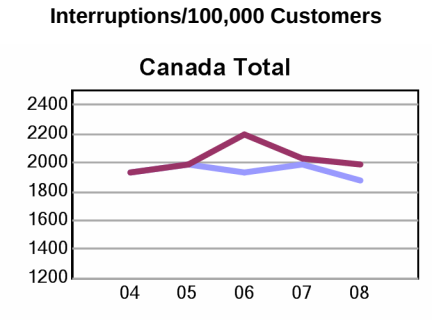






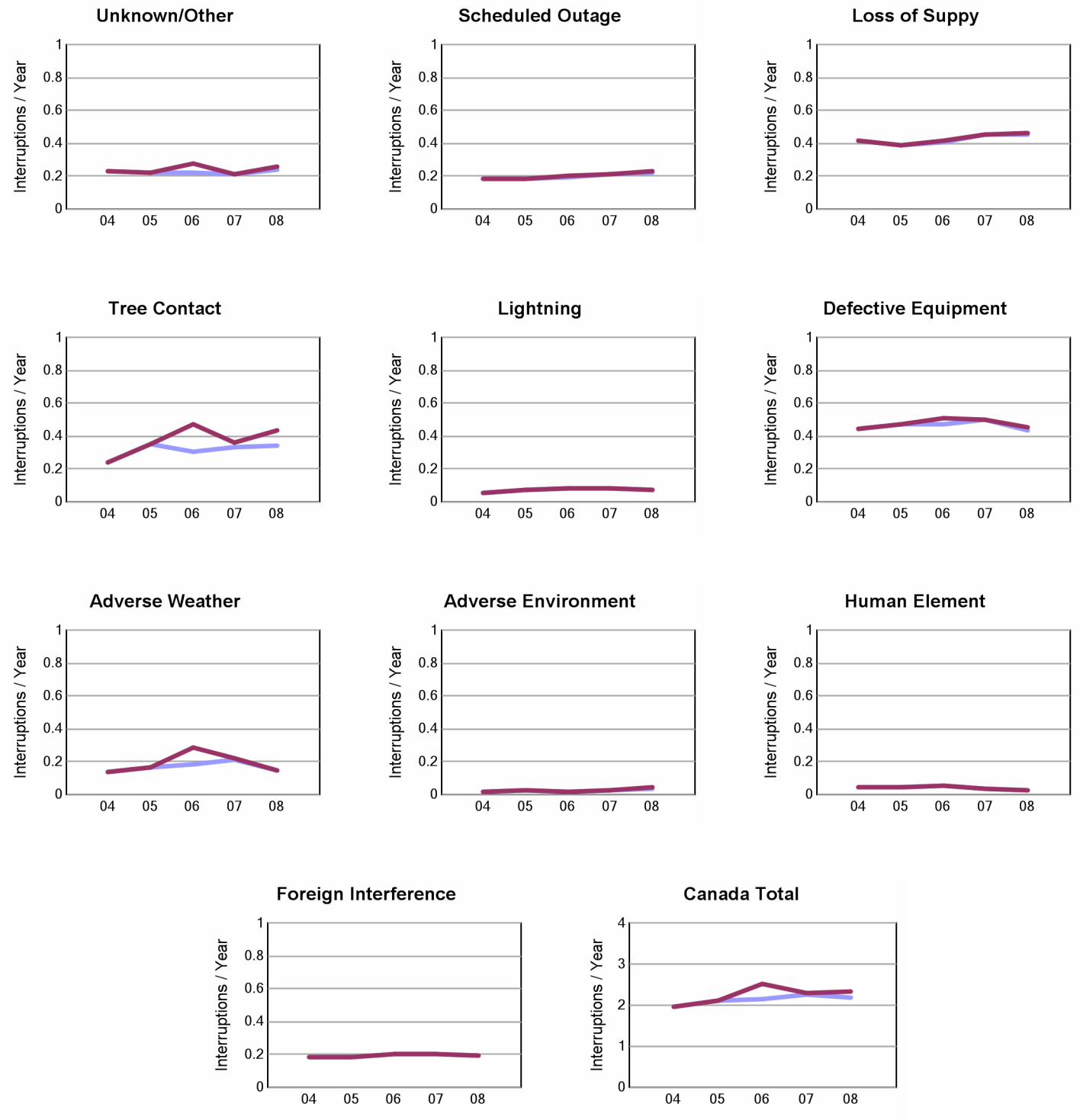






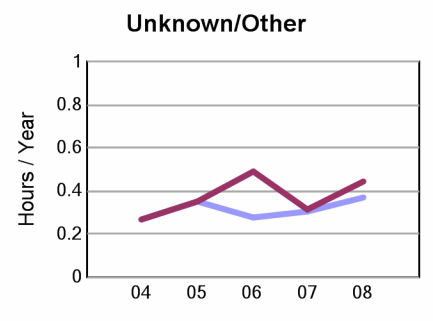
Note: ——— denotes the exclusion of Significant Event data (see Appendix E).

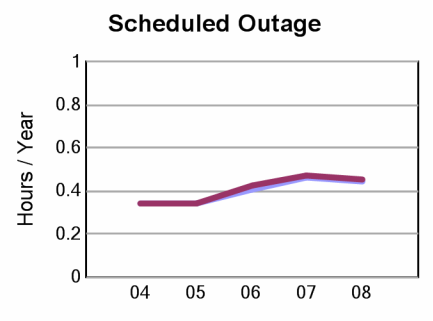
Graph 2-2 Causes of Interruptions for 2004-2008 Canadian Data - normalized to 100,000 customers

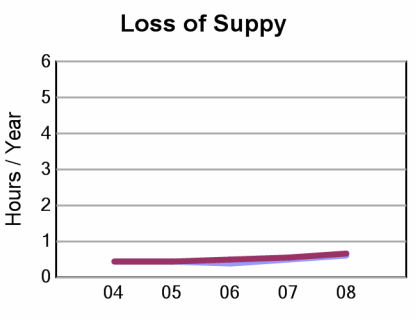


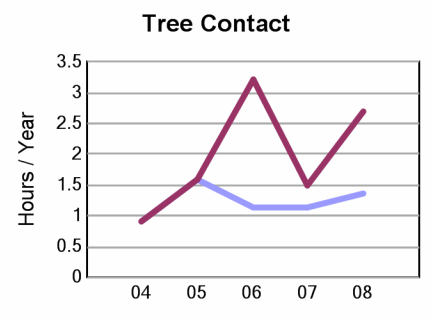
Note: denotes the exclusion of Significant Event data (see Appendix E).

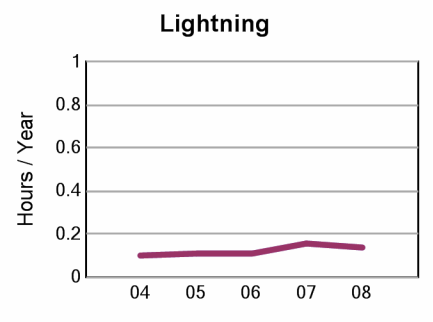
Graph 2-3 Contribution to SAIFI by Cause for 2004-2008 Canadian Data

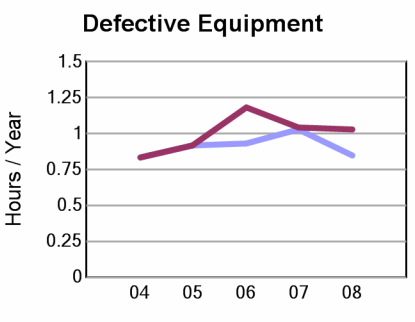


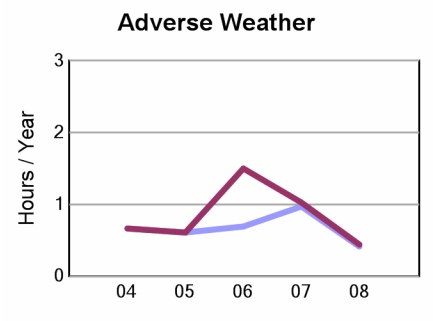


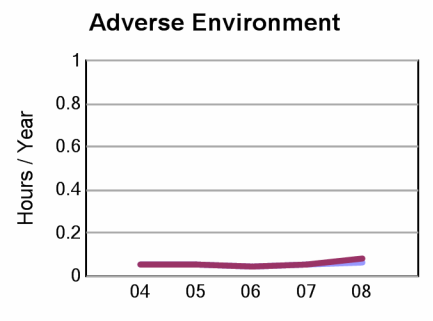


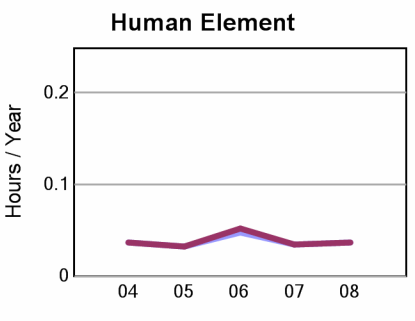


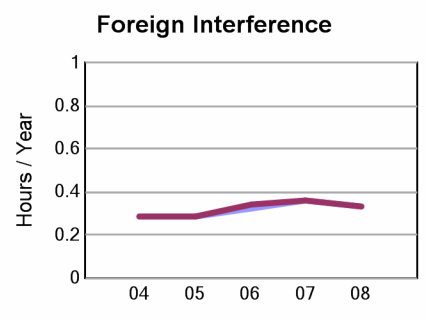


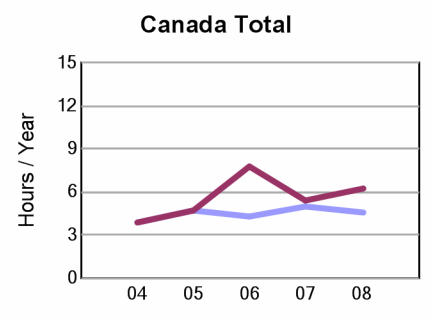






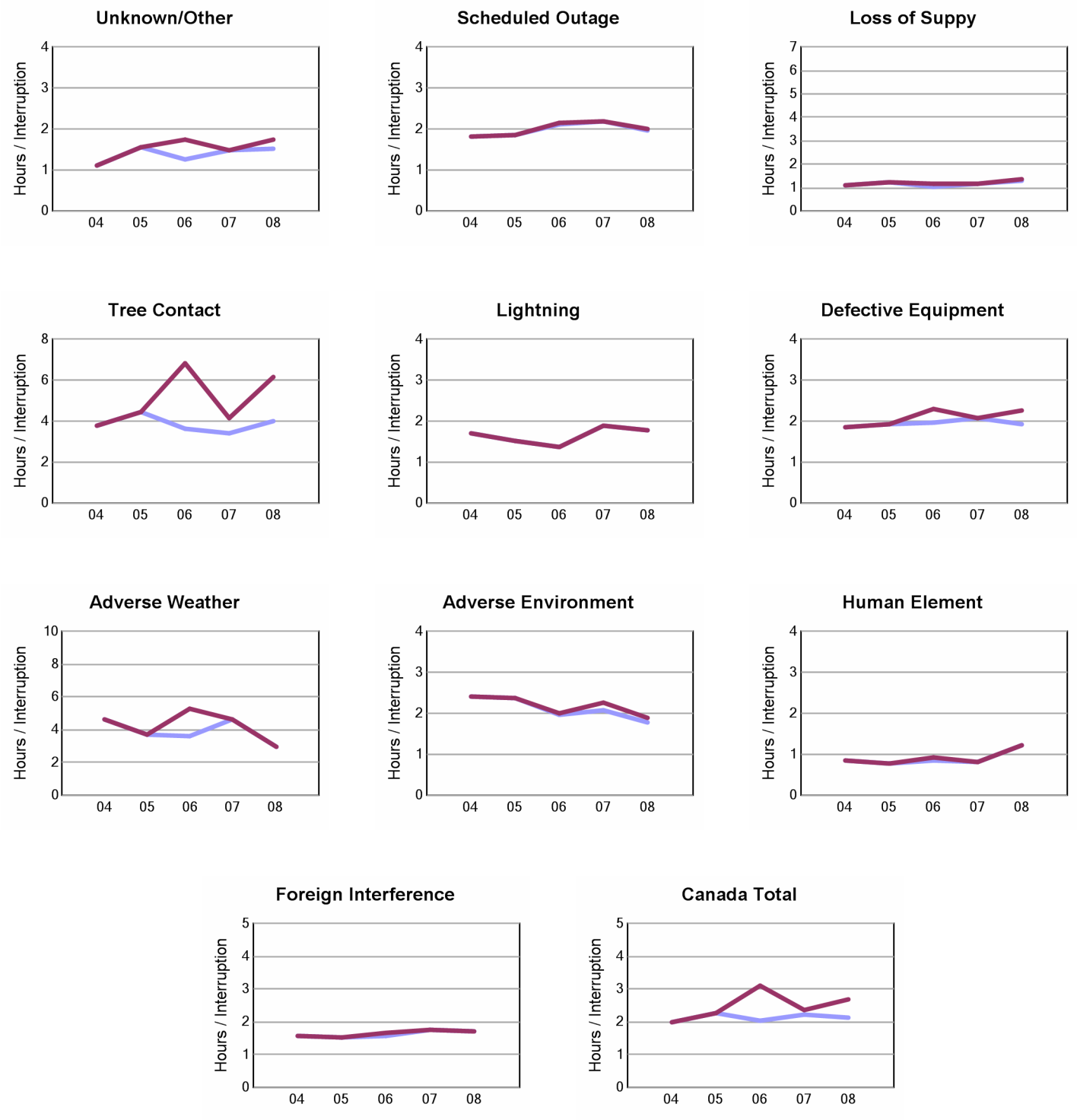






Note: ——— denotes the exclusion of Significant Event data (see Appendix E).

Graph 2-4 Contribution to SAIDI by Cause for 2004-2008 Canadian Data



Note: —— denotes the exclusion of Significant Event data (see Appendix E).

Graph 2-5 Contribution to CAIDI by Cause for 2004-2008 Canadian Data

3.0 TABULATION AND ANALYSIS OF SERVICE INTERRUPTION DATA

TABLE 3-1

SUMMARY OF INTERRUPTION DATA

(Including Derivation of Index of Reliability)

FOR YEARS 2003 - 2008

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.

IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2008

				(A)	(B)	(C)
YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	TOTAL INTERRUPTED CUST. HOURS	TOTAL AVAILABLE CUST. HOURS	INDEX OF RELIABILITY
2003	11,584,414	192,312	30,969,177	123,428,243	101,479,466,640	0.998784
2003**	11,584,414	191,066	27,455,476	59,205,835	101,479,466,640	0.999417
2004	8,048,747	155,127	15,900,677	31,781,217	70,507,023,720	0.999549
2005	8,343,702	165,724	17,743,180	40,031,202	73,090,829,520	0.999452
2006	8,496,987	186,835	21,469,181	66,667,370	74,433,606,120	0.999104
2006**	8,496,987	163,967	18,253,272	37,154,061	74,433,606,120	0.999501
2007	8,501,262	173,114	19,725,691	46,501,753	74,471,055,120	0.999376
2007**	8,501,262	169,364	19,288,544	42,707,227	74,471,055,120	0.999427
2008	8,586,360	170,556	20,100,130	53,976,755	75,216,513,600	0.999282
2008**	8,586,360	161,494	18,719,220	39,607,053	75,216,513,600	0.999474

*** Excludes Significant Events (see Appendix E)*

INTERNATIONAL UTILITIES IN 2008

2003	5,756,855	43,959	10,279,688	19,901,963	50,430,049,800	0.999605
2004	12,886,761	194,269	18,758,535	36,576,532	112,888,026,360	0.999676
2005	472,466	13,601	5,207,309	7,835,371	4,138,802,160	0.998107
2006	11,067,740	200,632	21,401,468	47,560,173	96,953,402,400	0.999510
2007	8,334,230	187,487	13,879,868	23,561,787	73,007,854,800	0.999677
2008	2,761,323	48,943	4,980,743	7,618,754	24,189,189,480	0.999685

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

TABLE 3-2

SYSTEM CAUSES OF SERVICE INTERRUPTION

FOR YEAR 2008

Canadian

8,586,360 CUSTOMERS IN 2008
8,501,262 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Unknown/Other									
2008	16,809	9.9	2,219,136	11.0	3,843,602	7.1	0.26	0.45	1.73
2007	15,610	9.0	1,793,451	9.1	2,649,295	5.7	0.21	0.31	1.48
5 YEAR AVERAGE	16,922	9.9	2,036,621	10.7	3,143,083	6.6	0.24	0.37	1.54
Scheduled Outage									
2008	26,231	15.4	1,959,267	9.7	3,912,625	7.2	0.23	0.46	2.00
2007	24,777	14.3	1,811,176	9.2	3,985,210	8.6	0.21	0.47	2.20
5 YEAR AVERAGE	24,574	14.4	1,705,398	9.0	3,431,607	7.2	0.20	0.41	2.01
Loss of Supply									
2008	3,295	1.9	4,000,703	19.9	5,498,248	10.2	0.47	0.64	1.37
2007	3,377	2.0	3,905,127	19.8	4,488,609	9.7	0.46	0.53	1.15
5 YEAR AVERAGE	3,223	1.9	3,608,283	19.0	4,358,276	9.1	0.43	0.52	1.21
Tree Contacts									
2008	31,440	18.4	3,754,870	18.7	23,044,388	42.7	0.44	2.68	6.14
2007	25,868	14.9	3,073,043	15.6	12,680,072	27.3	0.36	1.49	4.13
5 YEAR AVERAGE	27,032	15.9	3,146,753	16.6	16,729,945	35.0	0.37	1.99	5.32
Lightning									
2008	13,483	7.9	656,667	3.3	1,159,530	2.1	0.08	0.14	1.77
2007	14,294	8.3	706,242	3.6	1,347,283	2.9	0.08	0.16	1.91
5 YEAR AVERAGE	13,361	7.8	625,918	3.3	1,039,786	2.2	0.07	0.12	1.66
Defective Equipment									
2008	37,783	22.2	3,934,029	19.6	8,839,538	16.4	0.46	1.03	2.25
2007	37,335	21.6	4,239,277	21.5	8,851,219	19.0	0.50	1.04	2.09
5 YEAR AVERAGE	37,567	22.1	4,015,385	21.1	8,429,667	17.6	0.48	1.00	2.10
Adverse Weather									
2008	9,814	5.8	1,263,554	6.3	3,762,931	7.0	0.15	0.44	2.98
2007	17,974	10.4	1,877,825	9.5	8,634,137	18.6	0.22	1.02	4.60
5 YEAR AVERAGE	15,013	8.8	1,615,959	8.5	7,121,456	14.9	0.19	0.85	4.41

TABLE 3-2

SYSTEM CAUSES OF SERVICE INTERRUPTION

FOR YEAR 2008

Canadian

8,586,360 CUSTOMERS IN 2008
8,501,262 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Adverse Environment									
2008	3,724	2.2	367,766	1.8	696,504	1.3	0.04	0.08	1.89
2007	3,506	2.0	220,631	1.1	497,562	1.1	0.03	0.06	2.26
5 YEAR AVERAGE	3,601	2.1	227,339	1.2	486,583	1.0	0.03	0.06	2.14
Human Element									
2008	2,284	1.3	253,723	1.3	314,106	0.6	0.03	0.04	1.24
2007	2,304	1.3	349,060	1.8	288,935	0.6	0.04	0.03	0.83
5 YEAR AVERAGE	2,180	1.3	359,395	1.9	324,035	0.7	0.04	0.04	0.90
Foreign Interference									
2008	25,693	15.1	1,690,415	8.4	2,905,284	5.4	0.20	0.34	1.72
2007	28,069	16.2	1,749,859	8.9	3,079,432	6.6	0.21	0.36	1.76
5 YEAR AVERAGE	26,797	15.7	1,646,721	8.7	2,727,222	5.7	0.20	0.32	1.66
Total									
2008	170,556	100.0	20,100,130	100.0	53,976,755	100.0	2.34	6.29	2.69
2007	173,114	100.0	19,725,691	100.0	46,501,753	100.0	2.32	5.47	2.36
5 YEAR AVERAGE	170,271	100.0	18,987,772	100.0	47,791,659	100.0	2.26	5.69	2.52

TABLE 3-2A

SYSTEM CAUSES OF SERVICE INTERRUPTION

FOR YEAR 2008

International

2,761,323 CUSTOMERS IN 2008

8,334,230 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Unknown/Other									
2008	28,210	57.6	1,099,378	22.1	209,305	2.7	0.40	0.08	0.19
2007	93,349	49.8	2,417,470	17.4	2,643,588	11.2	0.29	0.32	1.09
5 YEAR AVERAGE	32,774	25.4	1,749,999	13.8	1,716,303	7.0	0.26	0.26	0.98
Scheduled Outage									
2008	8,000	16.3	1,234,717	24.8	3,468,920	45.5	0.45	1.26	2.81
2007	19,576	10.4	2,130,905	15.4	4,467,227	19.0	0.26	0.54	2.10
5 YEAR AVERAGE	14,265	11.1	1,692,951	13.4	3,716,631	15.2	0.25	0.56	2.20
Loss of Supply									
2008	835	1.7	539,512	10.8	678,765	8.9	0.20	0.25	1.26
2007	1,740	0.9	1,515,354	10.9	2,818,927	12.0	0.18	0.34	1.86
5 YEAR AVERAGE	1,317	1.0	1,432,351	11.3	2,000,402	8.2	0.21	0.30	1.40
Tree Contacts									
2008	1,373	2.8	228,280	4.6	469,804	6.2	0.08	0.17	2.06
2007	15,442	8.2	1,846,648	13.3	4,096,483	17.4	0.22	0.49	2.22
5 YEAR AVERAGE	16,476	12.8	1,672,100	13.2	6,154,048	25.2	0.25	0.92	3.68
Lightning									
2008	1,304	2.7	218,224	4.4	214,649	2.8	0.08	0.08	0.98
2007	15,354	8.2	1,048,081	7.6	1,832,089	7.8	0.13	0.22	1.75
5 YEAR AVERAGE	17,257	13.4	1,245,400	9.8	2,969,289	12.1	0.19	0.44	2.38
Defective Equipment									
2008	3,934	8.0	942,857	18.9	1,430,501	18.8	0.34	0.52	1.52
2007	18,946	10.1	2,566,691	18.5	3,840,591	16.3	0.31	0.46	1.50
5 YEAR AVERAGE	24,071	18.7	2,539,495	20.1	4,242,397	17.4	0.38	0.63	1.67
Adverse Weather									
2008	1,003	2.0	48,745	1.0	138,923	1.8	0.02	0.05	2.85
2007	3,731	2.0	445,521	3.2	1,527,164	6.5	0.05	0.18	3.43
5 YEAR AVERAGE	2,984	2.3	533,266	4.2	1,290,925	5.3	0.08	0.19	2.42

TABLE 3-2A

SYSTEM CAUSES OF SERVICE INTERRUPTION

FOR YEAR 2008

International

2,761,323 CUSTOMERS IN 2008

8,334,230 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Adverse Environment									
2008	664	1.4	92,635	1.9	177,967	2.3	0.03	0.06	1.92
2007	1,444	0.8	191,213	1.4	330,878	1.4	0.02	0.04	1.73
5 YEAR AVERAGE	1,518	1.2	188,768	1.5	425,557	1.7	0.03	0.06	2.25
Human Element									
2008	515	1.1	92,294	1.9	62,975	0.8	0.03	0.02	0.68
2007	1,258	0.7	399,768	2.9	235,568	1.0	0.05	0.03	0.59
5 YEAR AVERAGE	1,411	1.1	318,812	2.5	280,213	1.1	0.05	0.04	0.88
Foreign Interference									
2008	3,105	6.3	484,101	9.7	766,947	10.1	0.18	0.28	1.58
2007	16,647	8.9	1,318,217	9.5	1,769,271	7.5	0.16	0.21	1.34
5 YEAR AVERAGE	16,914	13.1	1,289,583	10.2	1,645,523	6.7	0.19	0.25	1.28
Total									
2008	48,943	100.0	4,980,743	100.0	7,618,754	100.0	1.80	2.76	1.53
2007	187,487	100.0	13,879,868	100.0	23,561,787	100.0	1.67	2.83	1.70
5 YEAR AVERAGE	128,986	100.0	12,845,585	100.0	24,630,524	100.0	1.81	3.47	1.92

4.0 SUMMARY

4.0 SUMMARY

ð For the 2008 reporting year, based on data for 8.6 million customers in Canada and 2.8 million international customers, the system indices are the following:

Canadian		***Excluding SE****	***International***	
SAIFI	2.34	2.18	SAIFI	1.80
SAIDI	6.29	4.61	SAIDI	2.76
CAIDI	2.69	2.12	CAIDI	1.53
IOR	0.999282	0.999474	IOR	0.999685

**SE - Significant Events*

Canadian Statistics

- ð The number of customers as compared to last year has remained relatively stable with a slight increase of 1.0%.
- ð Compared to the previous year, the total interrupted customer-hours increased by 13.8 %. (Derived from Table 3-1).
- ð The number of interruptions decreased by 1.5 %. (Table 3-1).
- ð The total customer interruptions increased by 1.9 %. (Table 3-1).
- ð The customer average interruption duration index or the average restoration time for affected customers was 2.69 hours, compared to 2.36 hours for 2007. (Table 3-2).
- ð The five major causes of service interruption of utilities are: (Derived from table 3-2)

Canadian:		***International:***	
ð Defective Equipment	22.2 %	ð Unknown/Other	57.6 %
ð Tree Contacts	18.4 %	ð Scheduled Outage	16.3 %
ð Scheduled Outage	15.4 %	ð Defective Equipment	8.0 %
ð Foreign Interference	15.1 %	ð Foreign Interference	6.3 %
ð Unknown/Other	9.9 %	ð Tree Contacts	2.8 %

5.0 SYSTEM CAUSES OF SERVICE OUTAGE

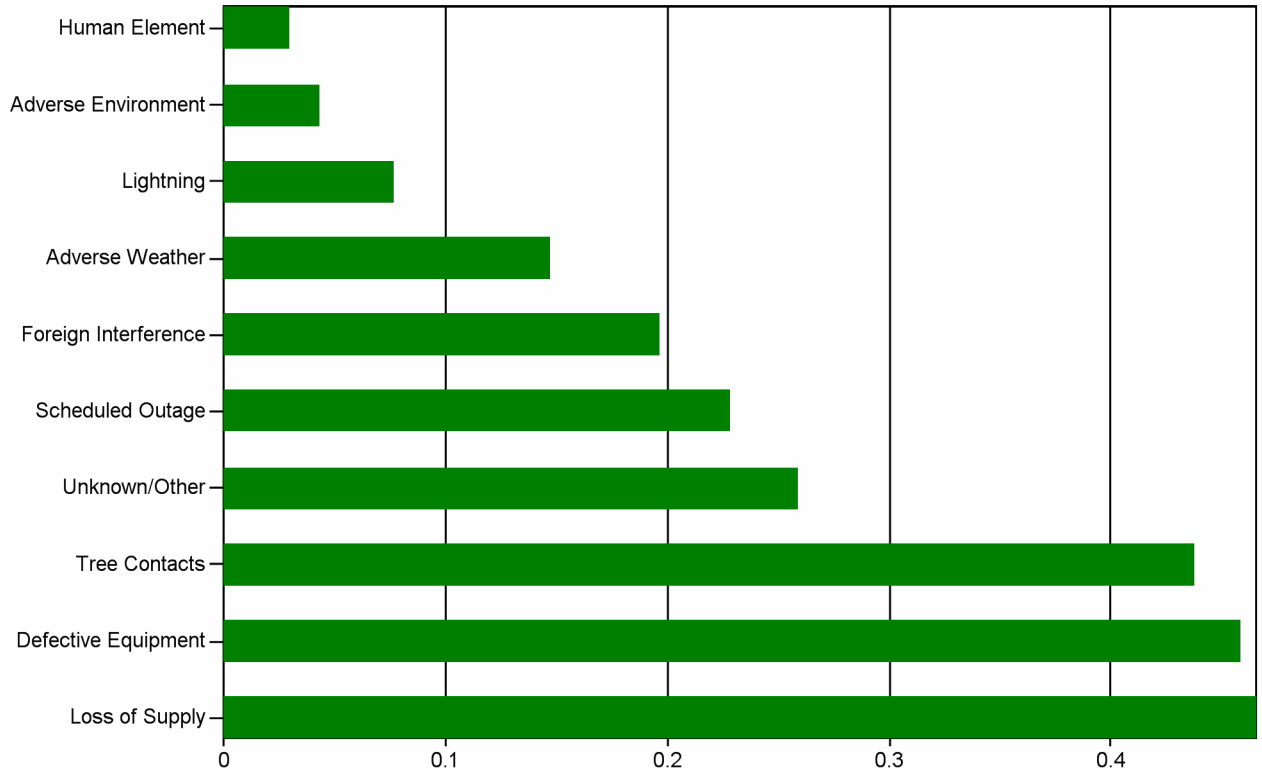
5.0 SYSTEM CAUSES OF SERVICE OUTAGE

SAIFI

Graphs 5-1 and 5-1a indicate the contributions to SAIFI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of interruptions attributed to each cause.

Canadian

	SAIFI	*% Interruptions*
Human Element	0.03	1.3
Adverse Environment	0.04	2.2
Lightning	0.08	7.9
Adverse Weather	0.15	5.8
Foreign Interference	0.20	15.1
Scheduled Outage	0.23	15.4
Unknown/Other	0.26	9.9
Tree Contacts	0.44	18.4
Defective Equipment	0.46	22.2
Loss of Supply	0.47	1.9

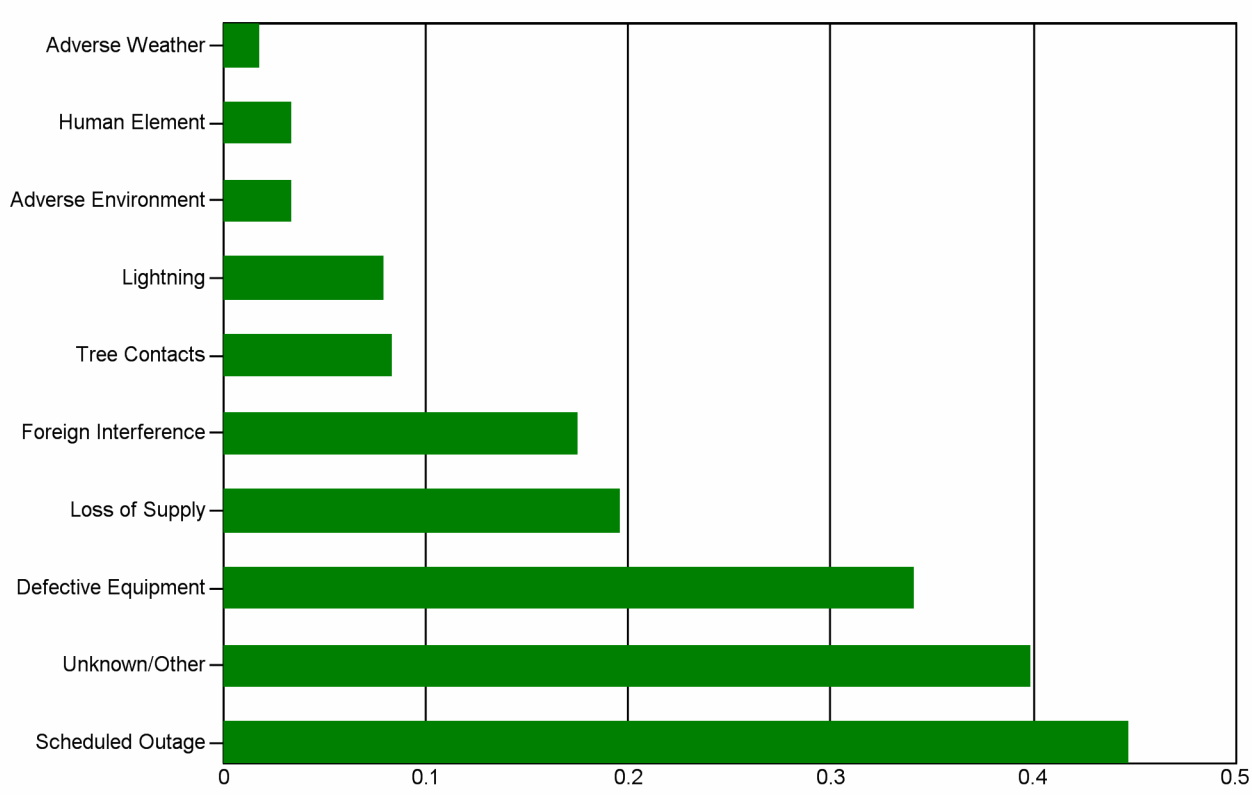


TOTAL SAIFI = 2.34

Graph 5-1 Contributions to SAIFI for 2008

International

	SAIFI	*% Interruptions*
Adverse Weather	0.02	2.0
Human Element	0.03	1.1
Adverse Environment	0.03	1.4
Lightning	0.08	2.7
Tree Contacts	0.08	2.8
Foreign Interference	0.18	6.3
Loss of Supply	0.20	1.7
Defective Equipment	0.34	8.0
Unknown/Other	0.40	57.6
Scheduled Outage	0.45	16.3



TOTAL SAIFI = 1.80

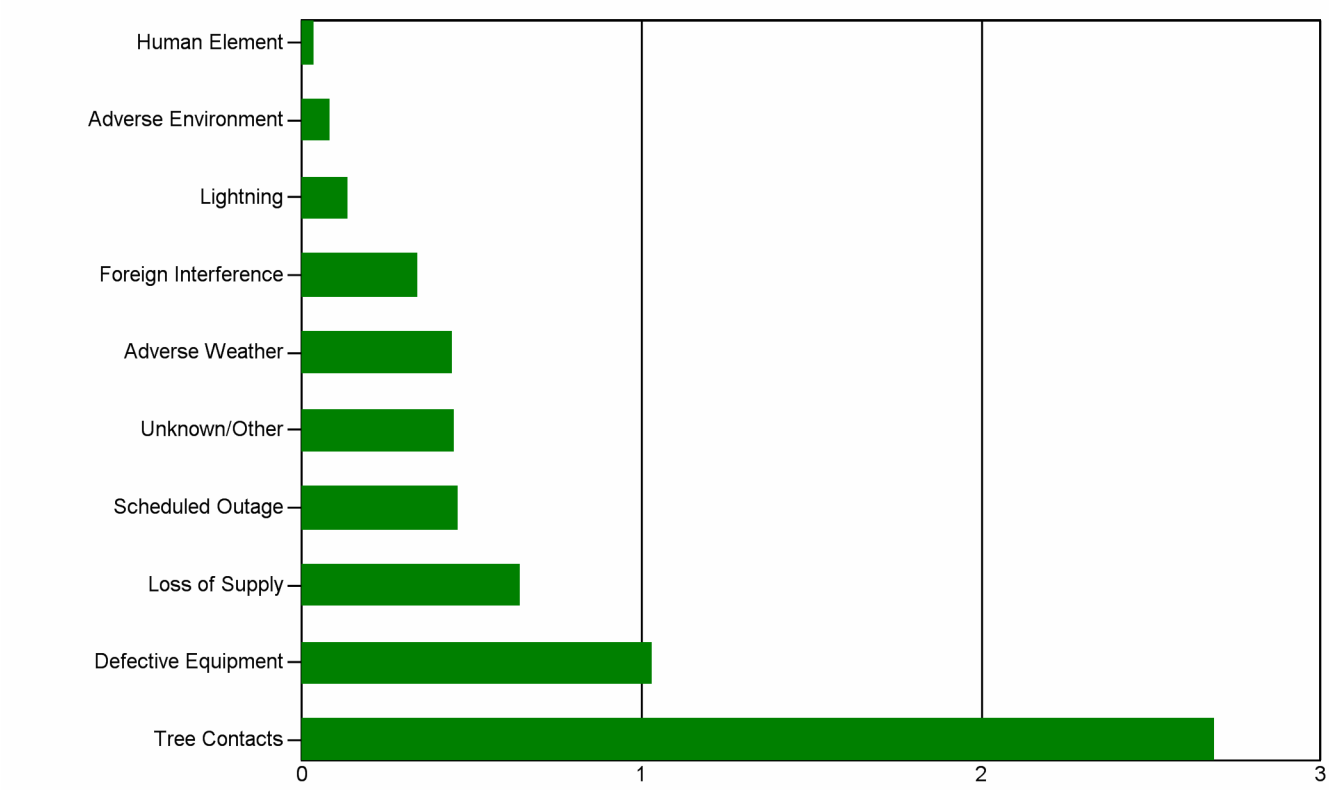
Graph 5-1a Contributions to SAIFI for 2008

SAIDI

Graphs 5-2 and 5-2a indicate the contributions to SAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer interruptions attributed to each cause.

Canadian

	SAIDI	*% Customer Interruptions*
Human Element	0.04	1.3
Adverse Environment	0.08	1.8
Lightning	0.14	3.3
Foreign Interference	0.34	8.4
Adverse Weather	0.44	6.3
Unknown/Other	0.45	11.0
Scheduled Outage	0.46	9.7
Loss of Supply	0.64	19.9
Defective Equipment	1.03	19.6
Tree Contacts	2.68	18.7

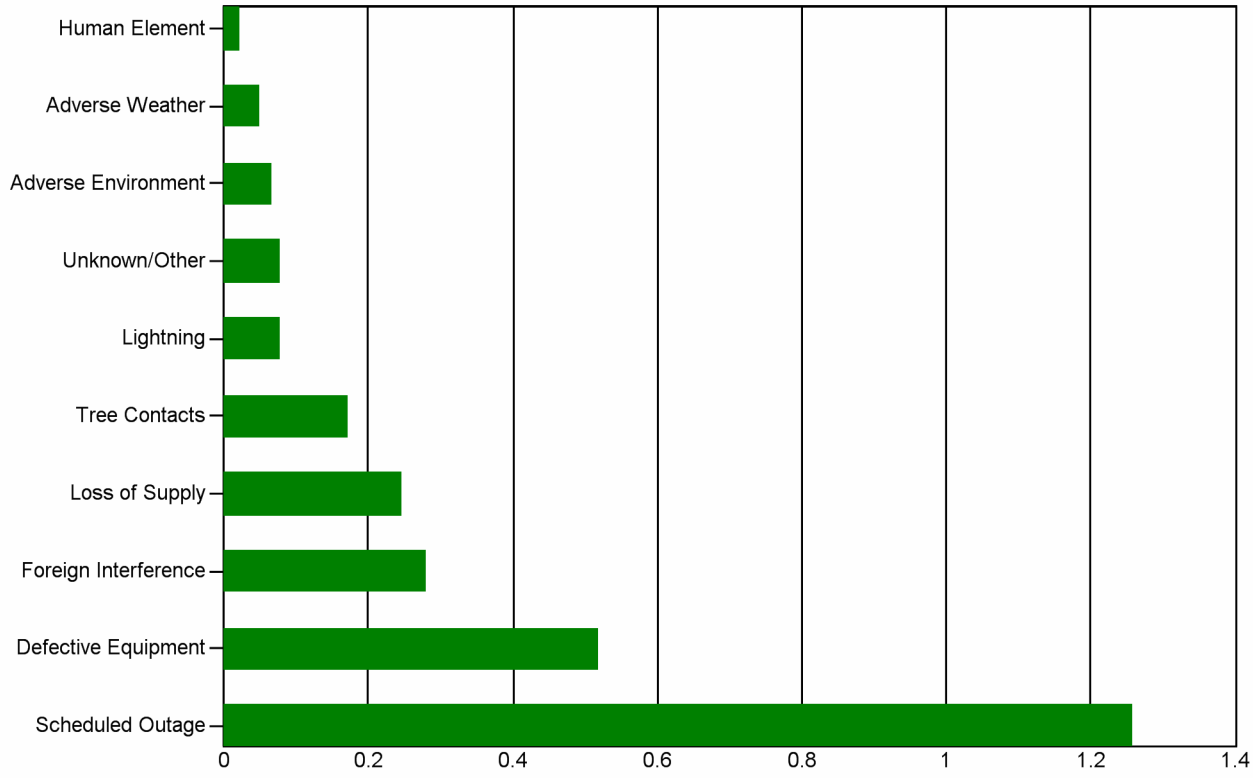


TOTAL SAIDI = 6.29

Graph 5-2 Contributions to SAIDI for 2008

International

	SAIDI	*% Customer Interruptions*
Human Element	0.02	1.9
Adverse Weather	0.05	1.0
Adverse Environment	0.06	1.9
Unknown/Other	0.08	22.1
Lightning	0.08	4.4
Tree Contacts	0.17	4.6
Loss of Supply	0.25	10.8
Foreign Interference	0.28	9.7
Defective Equipment	0.52	18.9
Scheduled Outage	1.26	24.8



TOTAL SAIDI = 2.76

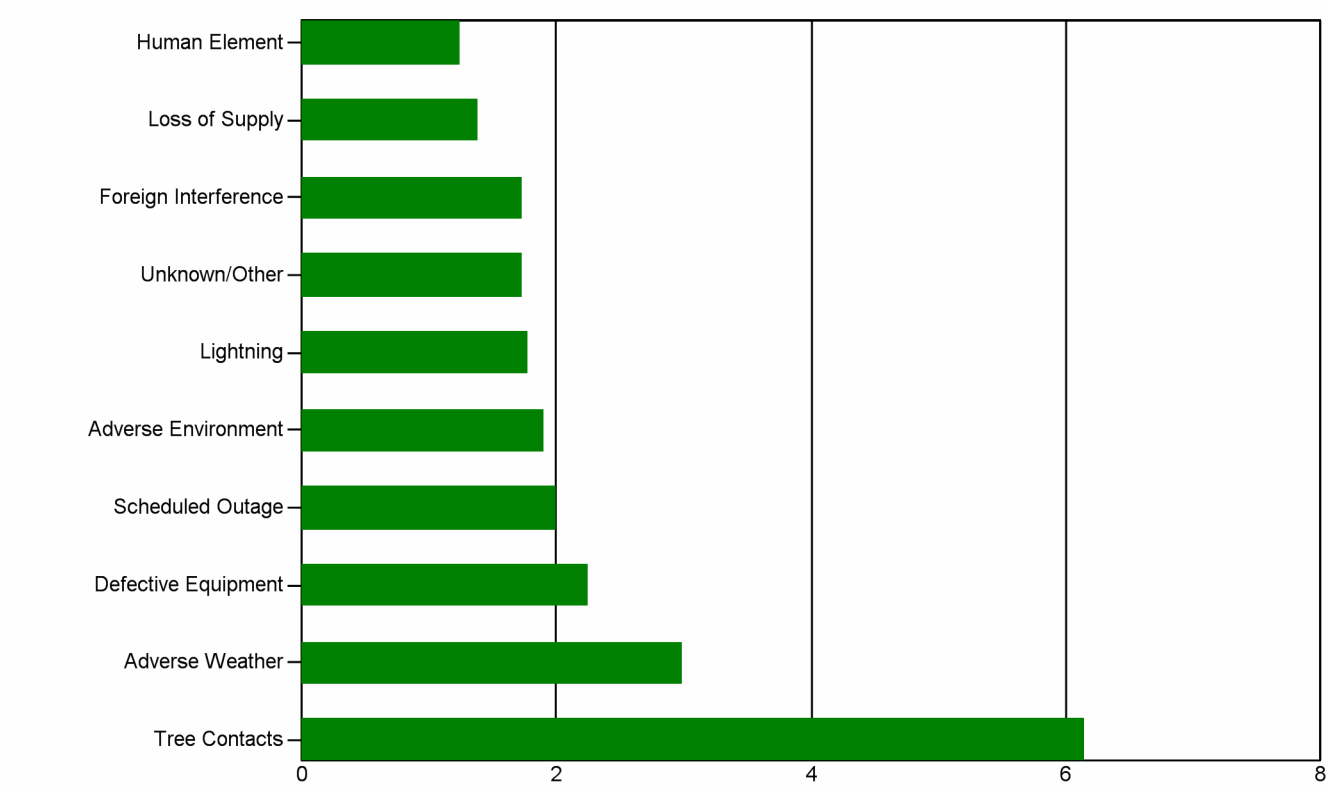
Graph 5-2a Contributions to SAIDI for 2008

CAIDI

Graphs 5-3 and 5-3a indicate the contributions to CAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer hours of interruption attributed to each cause.

Canadian

	CAIDI	*% Customer-hrs Interruptions*
Human Element	1.24	0.6
Loss of Supply	1.37	10.2
Foreign Interference	1.72	5.4
Unknown/Other	1.73	7.1
Lightning	1.77	2.1
Adverse Environment	1.89	1.3
Scheduled Outage	2.00	7.2
Defective Equipment	2.25	16.4
Adverse Weather	2.98	7.0
Tree Contacts	6.14	42.7

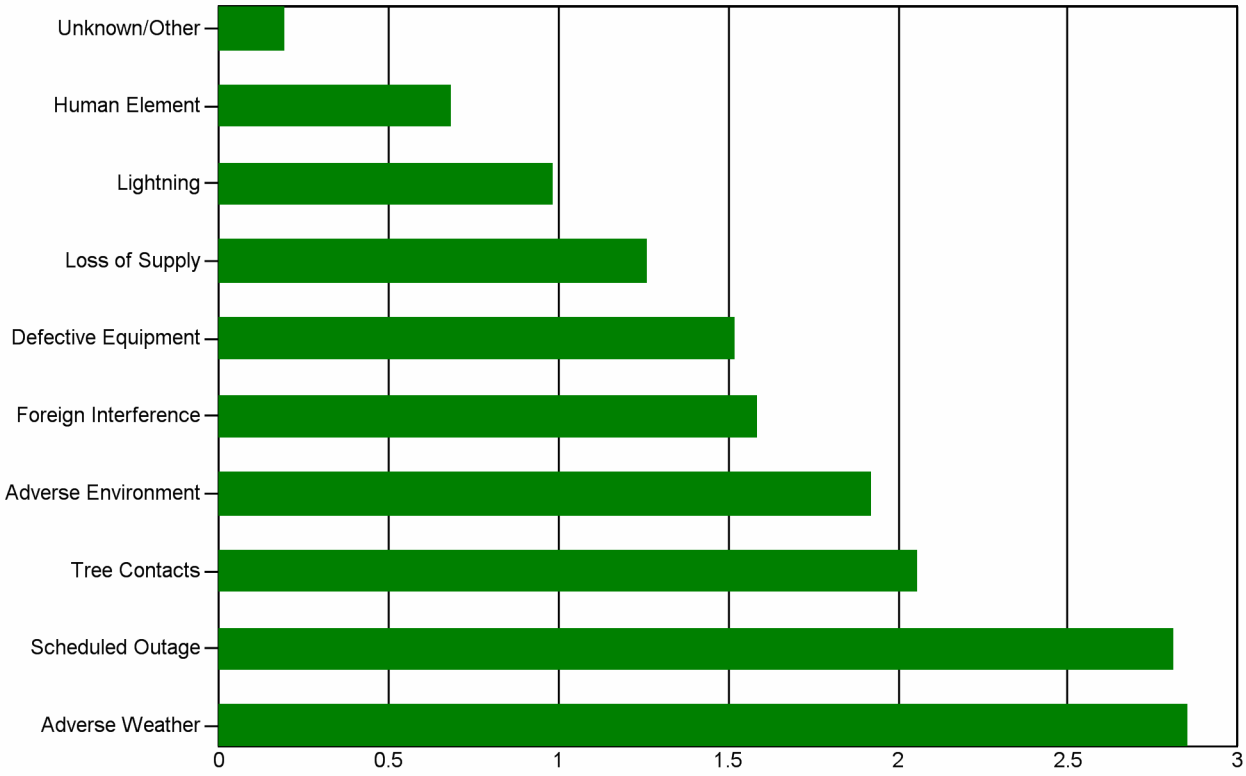


TOTAL CAIDI = 2.69

Graph 5-3 Contributions to CAIDI for 2008

International

	CAIDI	*% Customer-hrs Interruptions*
Unknown/Other	0.19	2.7
Human Element	0.68	0.8
Lightning	0.98	2.8
Loss of Supply	1.26	8.9
Defective Equipment	1.52	18.8
Foreign Interference	1.58	10.1
Adverse Environment	1.92	2.3
Tree Contacts	2.06	6.2
Scheduled Outage	2.81	45.5
Adverse Weather	2.85	1.8

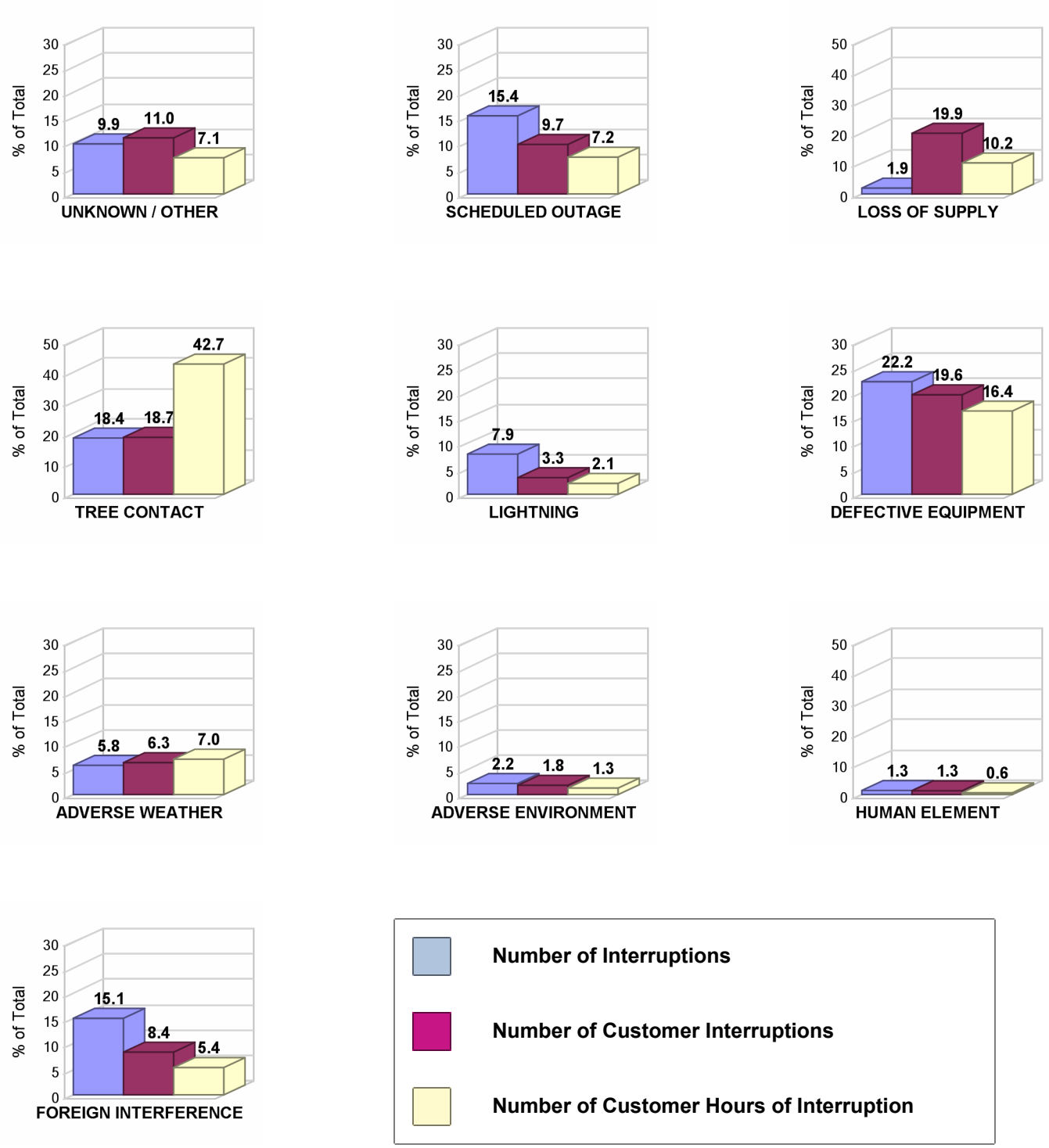


TOTAL CAIDI = 1.53

Graph 5-3a Contributions to CAIDI for 2008

Graph 5-4 is a comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruptions for Canadian participants.

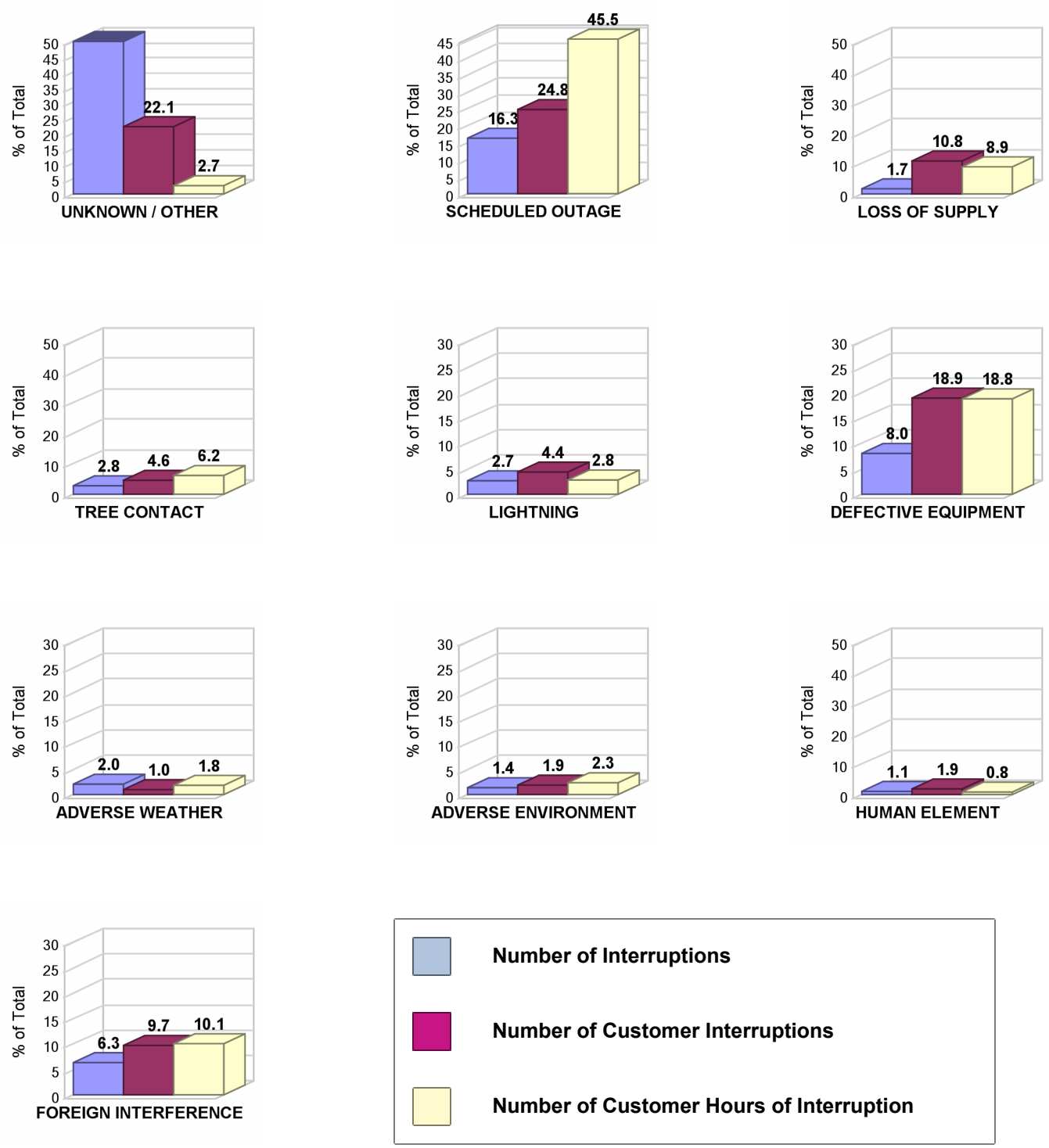
Canadian



Graph 5-4 Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2008 Canadian Data.

The following graphs show the comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruption.

International



Graph 5-4a Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2008 International Data.

The major causes of all interruptions, as compared to 2007 are:

Canadian

Unknown/Other	**2008**	**2007**
Interruptions	9.9 %	9.0 %
Customer Interruptions	11.0 %	9.1 %
Customer Hours of Interruption	7.1 %	5.7 %

Scheduled Outage	**2008**	**2007**
Interruptions	15.4 %	14.3 %
Customer Interruptions	9.7 %	9.2 %
Customer Hours of Interruption	7.2 %	8.6 %

Loss of Supply	**2008**	**2007**
Interruptions	1.9 %	2.0 %
Customer Interruptions	19.9 %	19.8 %
Customer Hours of Interruption	10.2 %	9.7 %

Tree Contacts	**2008**	**2007**
Interruptions	18.4 %	14.9 %
Customer Interruptions	18.7 %	15.6 %
Customer Hours of Interruption	42.7 %	27.3 %

Lightning	**2008**	**2007**
Interruptions	7.9 %	8.3 %
Customer Interruptions	3.3 %	3.6 %
Customer Hours of Interruption	2.1 %	2.9 %

Defective Equipment	**2008**	**2007**
Interruptions	22.2 %	21.6 %
Customer Interruptions	19.6 %	21.5 %
Customer Hours of Interruption	16.4 %	19.0 %

Adverse Weather	**2008**	**2007**
Interruptions	5.8 %	10.4 %
Customer Interruptions	6.3 %	9.5 %
Customer Hours of Interruption	7.0 %	18.6 %

Adverse Environment	**2008**	**2007**
Interruptions	2.2 %	2.0 %
Customer Interruptions	1.8 %	1.1 %
Customer Hours of Interruption	1.3 %	1.1 %

Human Element	**2008**	**2007**
Interruptions	1.3 %	1.3 %
Customer Interruptions	1.3 %	1.8 %
Customer Hours of Interruption	0.6 %	0.6 %

Foreign Interference	**2008**	**2007**
Interruptions	15.1 %	16.2 %
Customer Interruptions	8.4 %	8.9 %
Customer Hours of Interruption	5.4 %	6.6 %

The major causes of all interruptions, as compared to 2007 are:

International Participants

Unknown/Other	**2008**	**2007**
Interruptions	57.6 %	49.8 %
Customer Interruptions	22.1 %	17.4 %
Customer Hours of Interruption	2.7 %	11.2 %

Scheduled Outage	**2008**	**2007**
Interruptions	16.3 %	10.4 %
Customer Interruptions	24.8 %	15.4 %
Customer Hours of Interruption	45.5 %	19.0 %

Loss of Supply	**2008**	**2007**
Interruptions	1.7 %	0.9 %
Customer Interruptions	10.8 %	10.9 %
Customer Hours of Interruption	8.9 %	12.0 %

Tree Contacts	**2008**	**2007**
Interruptions	2.8 %	8.2 %
Customer Interruptions	4.6 %	13.3 %
Customer Hours of Interruption	6.2 %	17.4 %

Lightning	**2008**	**2007**
Interruptions	2.7 %	8.2 %
Customer Interruptions	4.4 %	7.6 %
Customer Hours of Interruption	2.8 %	7.8 %

Defective Equipment	**2008**	**2007**
Interruptions	8.0 %	10.1 %
Customer Interruptions	18.9 %	18.5 %
Customer Hours of Interruption	18.8 %	16.3 %

Adverse Weather	**2008**	**2007**
Interruptions	2.0 %	2.0 %
Customer Interruptions	1.0 %	3.2 %
Customer Hours of Interruption	1.8 %	6.5 %

Adverse Environment	**2008**	**2007**
Interruptions	1.4 %	0.8 %
Customer Interruptions	1.9 %	1.4 %
Customer Hours of Interruption	2.3 %	1.4 %

Human Element	**2008**	**2007**
Interruptions	1.1 %	0.7 %
Customer Interruptions	1.9 %	2.9 %
Customer Hours of Interruption	0.8 %	1.0 %

Foreign Interference	**2008**	**2007**
Interruptions	6.3 %	8.9 %
Customer Interruptions	9.7 %	9.5 %
Customer Hours of Interruption	10.1 %	7.5 %

6.0 TABULATION OF SERVICE INTERRUPTION DATA FOR REGION 1 (URBAN UTILITIES)

6.0 Region 1 (Urban Utilities)

City of Medicine Hat

City of Red Deer

CLP Power Hong Kong Limited

Enersource Hydro Mississauga

ENMAX Power Corporation

EPCOR

Horizon Utilities

Hydro Ottawa

Hydro-Sherbrooke

PowerStream Inc.

Saskatoon Light & Power

St. Thomas Energy

Toronto Hydro

* ATCO Electric – Grande Prairie

* B.C. Hydro - Vancouver/Burnaby District

* B.C. Hydro - Victoria District

* Hydro One - Combined Urban Areas

* Manitoba Hydro - Winnipeg

* NSPI - Halifax Urban

* NSPI - Provincial Urban Areas (excl. Halifax)

6. TABLE 1 (REGION 1)

SUMMARY OF INTERRUPTION DATA

(Including Derivation of Index of Reliability)

FOR YEARS 2003 - 2008

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.

IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2008

				(A)	(B)	(C)
YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	TOTAL INTERRUPTED CUST. HOURS	TOTAL AVAILABLE CUST. HOURS	INDEX OF RELIABILITY
2003	4,533,048	21,097	10,036,150	34,040,568	39,709,500,480	0.999143
2003**	4,533,048	21,021	8,210,375	8,281,393	39,709,500,480	0.999791
2004	2,914,654	11,870	3,313,473	2,683,761	25,532,369,040	0.999895
2005	3,416,392	14,342	4,265,295	3,997,145	29,927,593,920	0.999866
2006	3,899,881	23,287	5,819,174	8,652,934	34,162,957,560	0.999747
2007	3,797,916	19,370	5,734,196	7,063,980	33,269,744,160	0.999788
2007**	3,797,916	19,058	5,648,352	6,506,060	33,269,744,160	0.999804
2008	3,754,982	16,821	5,409,457	6,492,473	32,893,642,320	0.999803

*** Excludes Significant Events (see Appendix E)*

INTERNATIONAL UTILITIES IN 2008

2003	2,028,434	0	1,286,886	1,715,256	17,769,081,840	0.999903
2004	6,235,881	62,442	5,030,615	6,674,023	54,626,317,560	0.999878
2006	4,367,632	64,520	6,516,023	9,673,999	38,260,456,320	0.999747
2007	4,546,266	68,094	4,480,666	5,812,348	39,825,290,160	0.999854
2008	2,275,769	7,294	424,305	998,342	19,935,736,440	0.999950

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

6. TABLE 2 (REGION 1)

SYSTEM CAUSES OF SERVICE INTERRUPTIONS

FOR YEAR 2008

Canadian

3,754,982 CUSTOMERS IN 2008
3,797,916 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Unknown/Other									
2008	1,734	10.3	578,739	10.7	714,311	11.0	0.15	0.19	1.23
2007	1,265	6.5	471,712	8.2	310,968	4.4	0.12	0.08	0.66
5 YEAR AVERAGE	1,263	7.4	450,319	9.2	355,113	6.1	0.13	0.10	0.79
Scheduled Outage									
2008	3,567	21.2	216,635	4.0	421,482	6.5	0.06	0.11	1.95
2007	5,401	27.9	249,346	4.3	453,393	6.4	0.07	0.12	1.82
5 YEAR AVERAGE	4,145	24.2	188,032	3.8	303,274	5.2	0.05	0.09	1.61
Loss of Supply									
2008	351	2.1	1,031,291	19.1	625,383	9.6	0.27	0.17	0.61
2007	494	2.6	1,074,315	18.7	637,860	9.0	0.28	0.17	0.59
5 YEAR AVERAGE	315	1.8	806,642	16.4	502,503	8.7	0.23	0.14	0.62
Tree Contacts									
2008	1,708	10.2	480,321	8.9	1,169,429	18.0	0.13	0.31	2.43
2007	1,539	7.9	463,788	8.1	1,030,554	14.6	0.12	0.27	2.22
5 YEAR AVERAGE	1,389	8.1	430,375	8.8	897,535	15.5	0.12	0.25	2.09
Lightning									
2008	581	3.5	229,760	4.2	259,096	4.0	0.06	0.07	1.13
2007	625	3.2	301,168	5.3	261,599	3.7	0.08	0.07	0.87
5 YEAR AVERAGE	537	3.1	251,126	5.1	208,615	3.6	0.07	0.06	0.83
Defective Equipment									
2008	4,269	25.4	1,482,248	27.4	1,815,950	28.0	0.39	0.48	1.23
2007	5,122	26.4	1,694,475	29.6	2,160,883	30.6	0.45	0.57	1.28
5 YEAR AVERAGE	4,030	23.5	1,449,427	29.5	1,576,416	27.3	0.41	0.44	1.09
Adverse Weather									
2008	907	5.4	427,536	7.9	478,784	7.4	0.11	0.13	1.12
2007	1,150	5.9	582,291	10.2	1,201,766	17.0	0.15	0.32	2.06
5 YEAR AVERAGE	1,974	11.5	480,994	9.8	1,128,875	19.5	0.14	0.32	2.35

6. TABLE 2 (REGION 1)

SYSTEM CAUSES OF SERVICE INTERRUPTIONS

FOR YEAR 2008

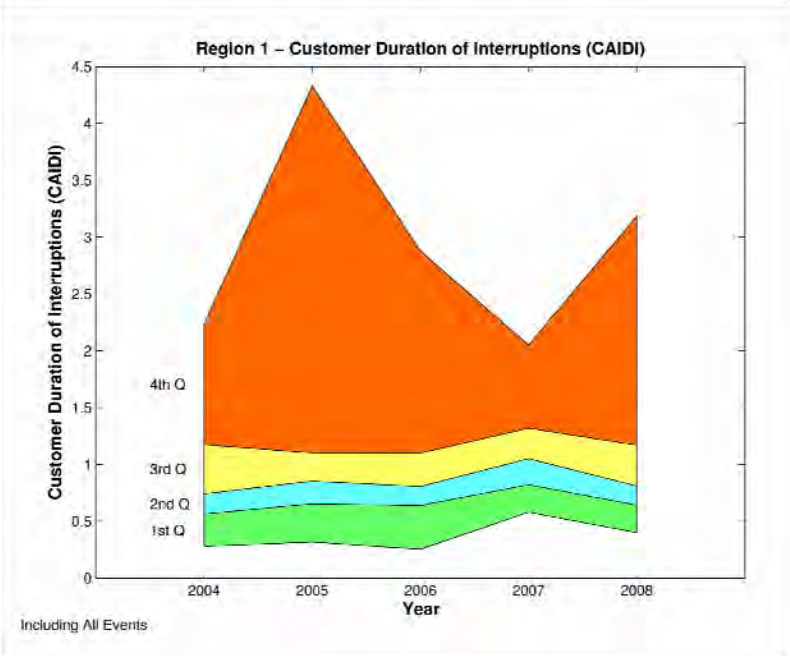
Canadian

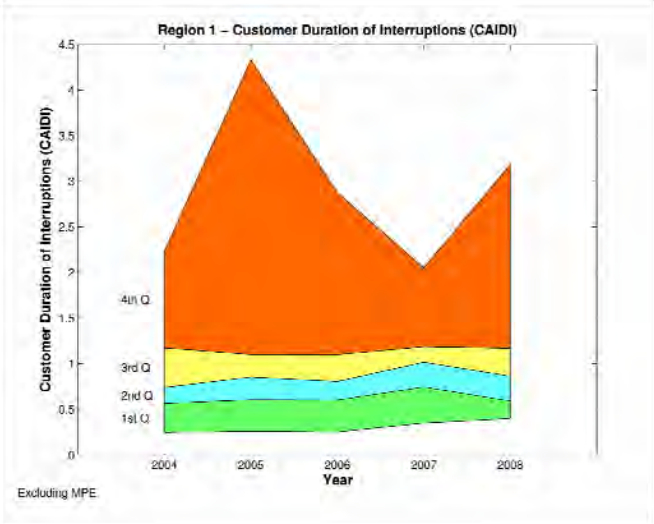
3,754,982 CUSTOMERS IN 2008

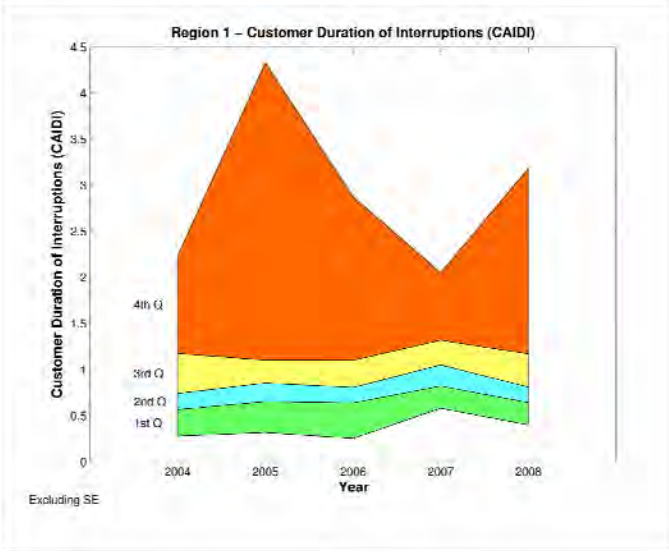
3,797,916 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Adverse Environment									
2008	877	5.2	238,252	4.4	339,803	5.2	0.06	0.09	1.43
2007	756	3.9	83,469	1.5	144,948	2.1	0.02	0.04	1.74
5 YEAR AVERAGE	794	4.6	107,100	2.2	156,087	2.7	0.03	0.04	1.46
Human Element									
2008	503	3.0	98,055	1.8	100,635	1.6	0.03	0.03	1.03
2007	540	2.8	164,585	2.9	108,348	1.5	0.04	0.03	0.66
5 YEAR AVERAGE	476	2.8	162,836	3.3	93,089	1.6	0.05	0.03	0.57
Foreign Interference									
2008	2,324	13.8	626,620	11.6	567,600	8.7	0.17	0.15	0.91
2007	2,478	12.8	649,047	11.3	753,662	10.7	0.17	0.20	1.16
5 YEAR AVERAGE	2,216	12.9	581,466	11.8	556,553	9.6	0.16	0.16	0.96
Total									
2008	16,821	100.0	5,409,457	100.0	6,492,473	100.0	1.44	1.73	1.20
2007	19,370	100.0	5,734,196	100.0	7,063,980	100.0	1.51	1.86	1.23
5 YEAR AVERAGE	17,138	100.0	4,908,319	100.0	5,778,059	100.0	1.38	1.62	1.18

Graph 6-1: Region 1 – Customer Average Interruption Duration Index

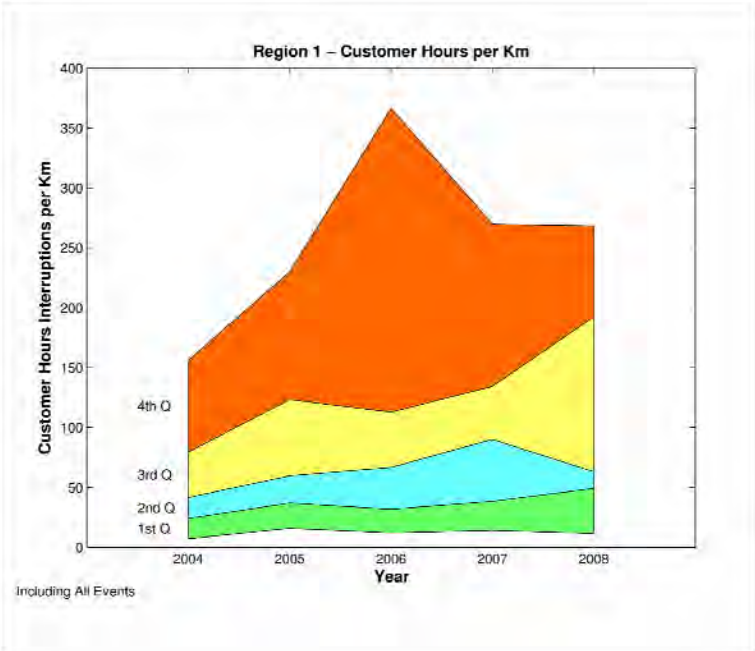


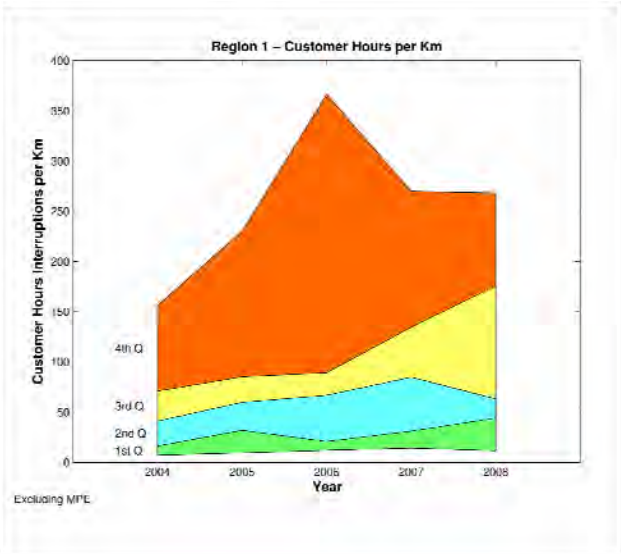


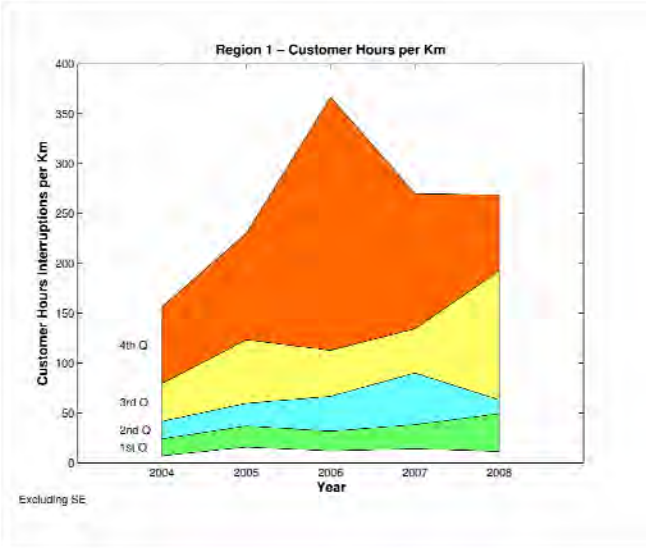


For an explanation of quartile graphs and what they represent, please go to page 6.

Graph 6-2: Region 1 – Customer Hours

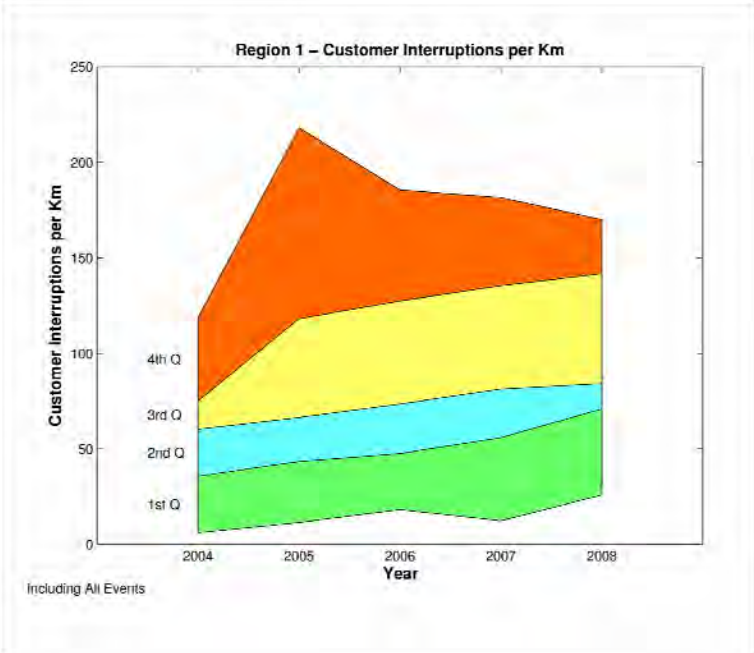


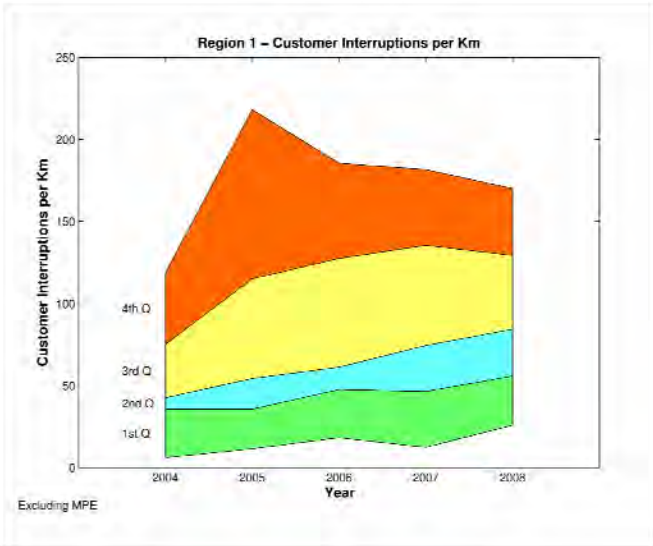


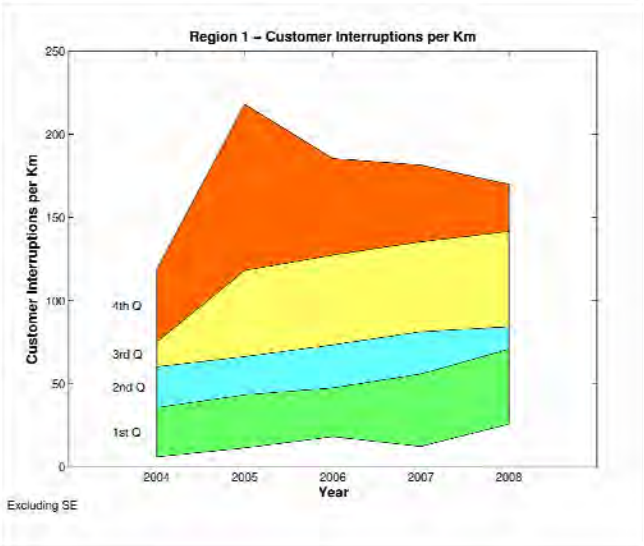


For an explanation of quartile graphs and what they represent, please go to page 6.

Graph 6-3: Region 1 – Customer Interruptions per Km

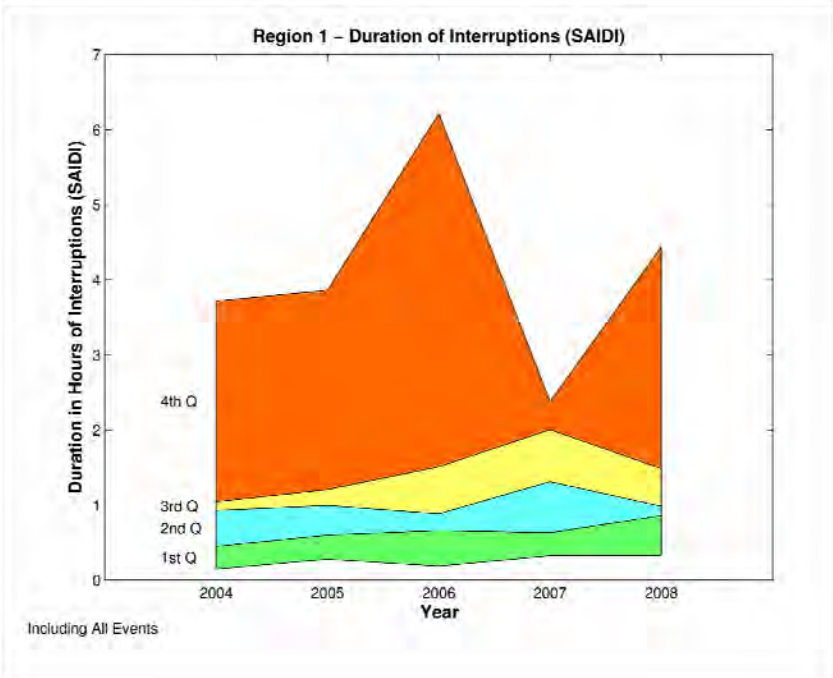


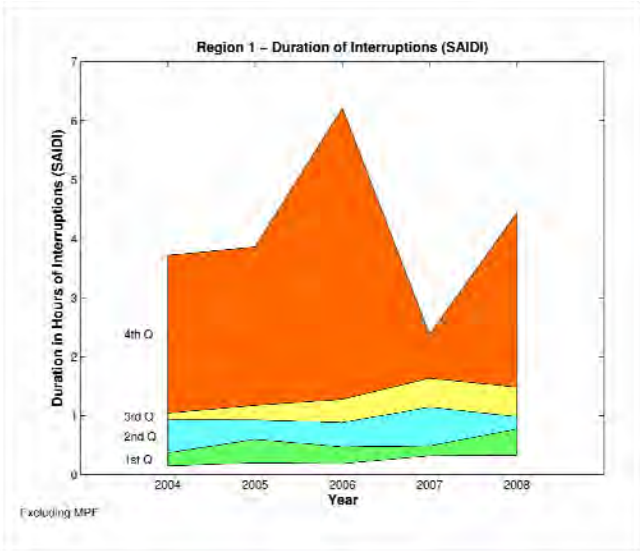


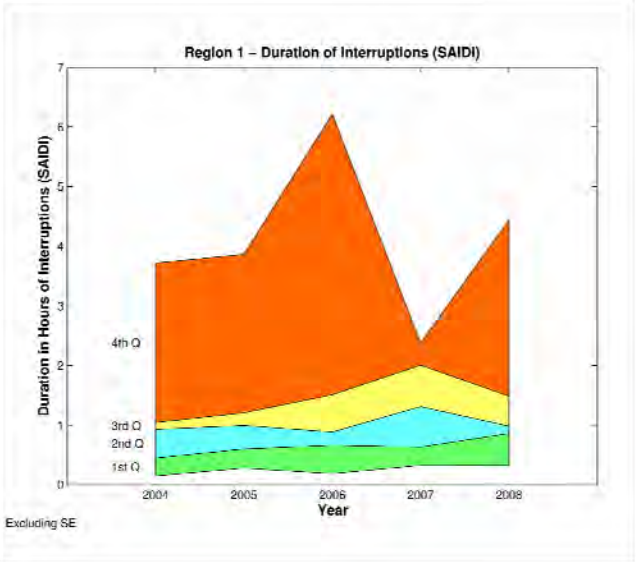


For an explanation of quartile graphs and what they represent, please go to page 6.

Graph 6-4: Region 1 – System Average Interruption Duration Index

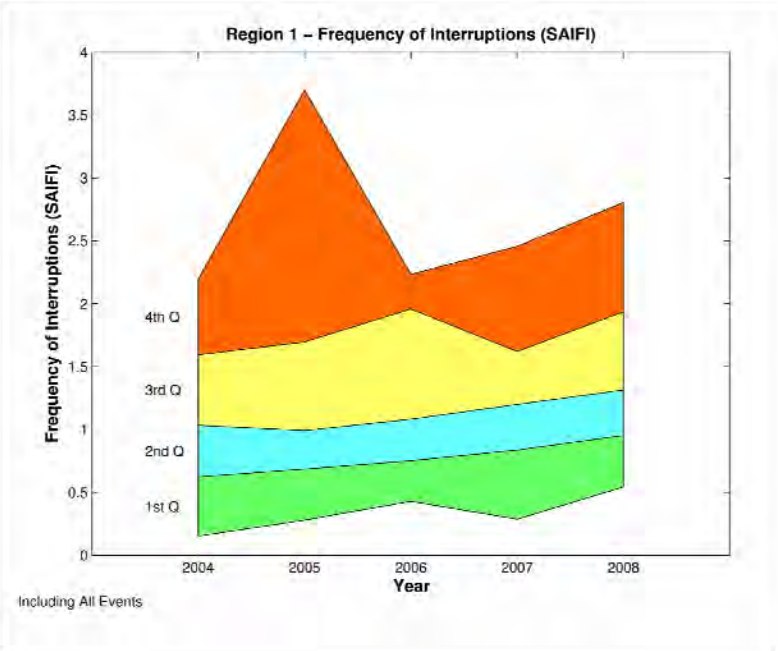


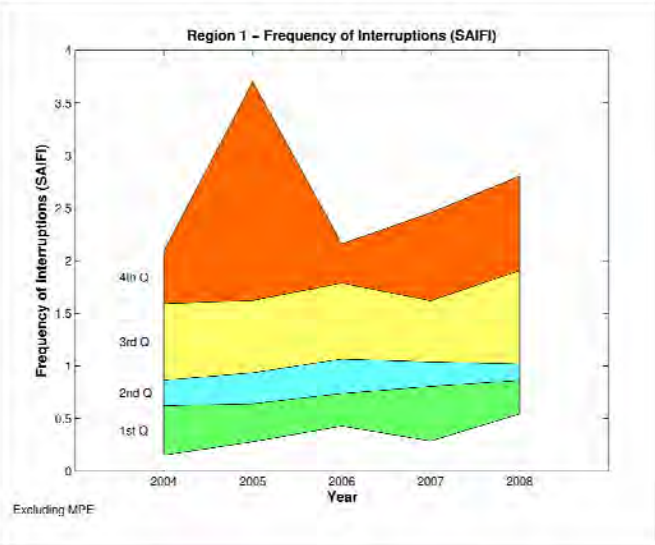


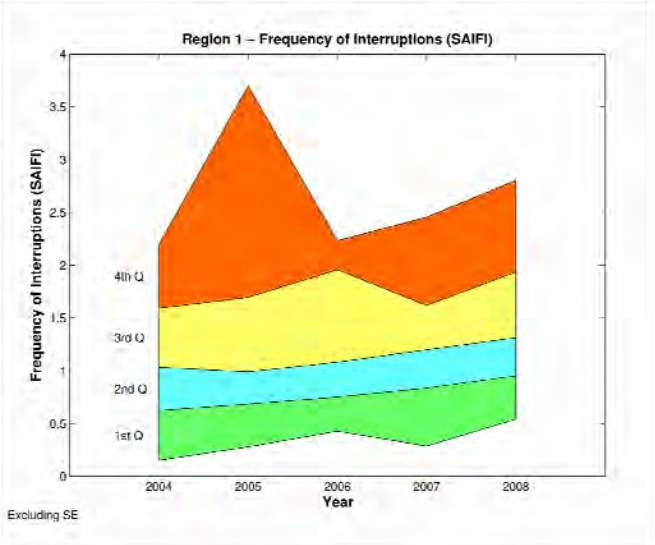


For an explanation of quartile graphs and what they represent, please go to page 6.

Graph 6-5: Region 1 – System Average Interruption Frequency Index







For an explanation of quartile graphs and what they represent, please go to page 6.

7.0 TABULATION OF SERVICE INTERRUPTION DATA FOR REGION 2 (URBAN/RURAL UTILITIES)

7.0 Region 2 (Urban / Rural Utilities)

ATCO Electric

B.C. Hydro

BELCO (Bermuda)

Brookfield Power (Great Lakes Power)

FortisAlberta

FortisBC

Hydro One

Manitoba Hydro

Maritime Electric Company

New Brunswick Power

Newfoundland & Labrador Hydro

Newfoundland Power

Nova Scotia Power Inc.

SaskPower

St. Lucia Electricity Services

Trinidad & Tobago Electricity Commission

Veridian Connections

7. TABLE 1 (REGION 2)

SUMMARY OF INTERRUPTION DATA

(Including Derivation of Index of Reliability)

FOR YEARS 2003 - 2008

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.

IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2008

				(A)	(B)	(C)
YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	TOTAL INTERRUPTED CUST. HOURS	TOTAL AVAILABLE CUST. HOURS	INDEX OF RELIABILITY
2003	9,118,928	181,351	25,508,541	94,459,739	79,881,809,280	0.998818
2003**	9,118,928	180,181	23,820,612	55,996,506	79,881,809,280	0.999299
2004	5,622,809	145,922	12,918,162	29,707,041	49,255,806,840	0.999397
2005	5,700,736	156,194	14,000,977	37,102,285	49,938,447,360	0.999257
2006	5,788,383	176,995	17,672,285	63,488,650	50,706,235,080	0.998748
2006**	5,788,383	154,127	14,456,376	33,975,341	50,706,235,080	0.999330
2007	5,893,451	164,296	15,817,912	42,965,867	51,626,630,760	0.999168
2007**	5,893,451	160,546	15,380,765	39,171,341	51,626,630,760	0.999241
2008	5,989,214	162,469	16,515,698	51,270,337	52,465,514,640	0.999023
2008**	5,989,214	153,407	15,134,787	36,900,636	52,465,514,640	0.999297

*** Excludes Significant Events (see Appendix E)*

INTERNATIONAL UTILITIES IN 2008

2003	3,728,421	43,959	8,992,802	18,186,707	32,660,967,960	0.999443
2004	6,650,880	131,827	13,727,920	29,902,509	58,261,708,800	0.999487
2005	472,466	13,601	5,207,309	7,835,371	4,138,802,160	0.998107
2006	6,700,108	136,112	14,885,450	37,886,175	58,692,946,080	0.999355
2007	3,787,964	119,393	9,399,202	17,749,439	33,182,564,640	0.999465
2008	485,554	41,649	4,556,438	6,620,412	4,253,453,040	0.998444

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

7. TABLE 2 (REGION 2)

SYSTEM CAUSES OF SERVICE INTERRUPTIONS

FOR YEAR 2008

Canadian

5,989,214 CUSTOMERS IN 2008
5,893,451 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Unknown/Other									
2008	16,374	10.1	1,903,675	11.5	3,714,694	7.2	0.32	0.62	1.95
2007	15,108	9.2	1,444,358	9.1	2,535,783	5.9	0.25	0.43	1.76
5 YEAR AVERAGE	16,414	10.2	1,704,135	11.1	3,045,970	6.8	0.29	0.53	1.79
Scheduled Outage									
2008	23,602	14.5	1,880,892	11.4	3,759,457	7.3	0.31	0.63	2.00
2007	21,926	13.3	1,734,822	11.0	3,837,648	8.9	0.29	0.65	2.21
5 YEAR AVERAGE	21,533	13.4	1,601,633	10.4	3,268,905	7.3	0.28	0.56	2.04
Loss of Supply									
2008	3,217	2.0	3,465,341	21.0	5,300,418	10.3	0.58	0.88	1.53
2007	3,267	2.0	3,284,210	20.8	4,172,810	9.7	0.56	0.71	1.27
5 YEAR AVERAGE	3,092	1.9	3,096,682	20.1	4,080,419	9.1	0.53	0.70	1.32
Tree Contacts									
2008	31,125	19.2	3,548,464	21.5	22,795,085	44.5	0.59	3.81	6.42
2007	25,422	15.5	2,796,241	17.7	12,358,729	28.8	0.47	2.10	4.42
5 YEAR AVERAGE	26,616	16.5	2,906,423	18.9	16,408,112	36.5	0.50	2.83	5.65
Lightning									
2008	13,100	8.1	442,451	2.7	931,821	1.8	0.07	0.16	2.11
2007	13,960	8.5	467,021	3.0	1,177,736	2.7	0.08	0.20	2.52
5 YEAR AVERAGE	12,967	8.0	398,439	2.6	868,933	1.9	0.07	0.15	2.18
Defective Equipment									
2008	35,496	21.8	2,770,624	16.8	7,870,859	15.4	0.46	1.31	2.84
2007	34,860	21.2	3,032,520	19.2	7,723,587	18.0	0.51	1.31	2.55
5 YEAR AVERAGE	35,008	21.7	2,838,754	18.5	7,409,082	16.5	0.49	1.28	2.61
Adverse Weather									
2008	9,250	5.7	914,276	5.5	3,445,082	6.7	0.15	0.58	3.77
2007	17,365	10.6	1,391,492	8.8	7,777,983	18.1	0.24	1.32	5.59
5 YEAR AVERAGE	14,474	9.0	1,281,011	8.3	6,727,088	15.0	0.22	1.16	5.25

7. TABLE 2 (REGION 2)

SYSTEM CAUSES OF SERVICE INTERRUPTIONS

FOR YEAR 2008

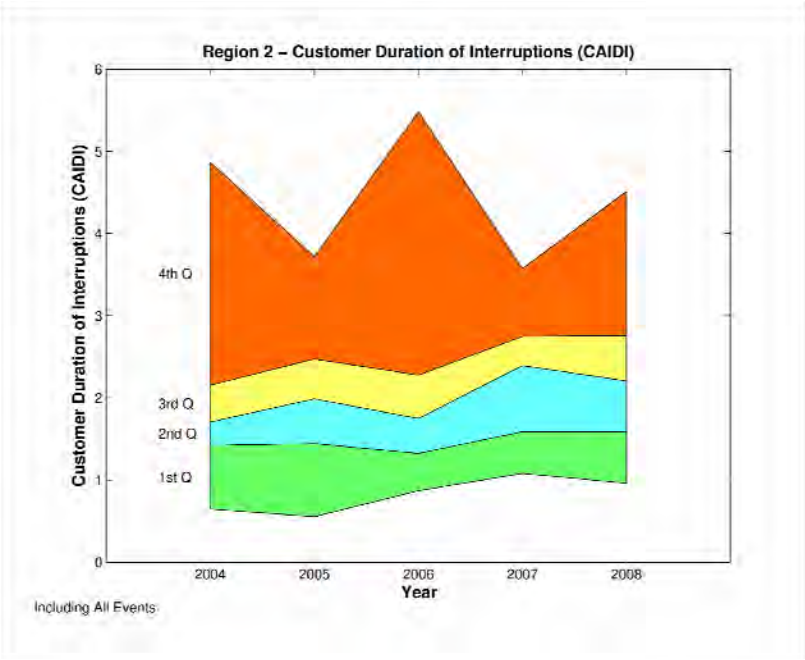
Canadian

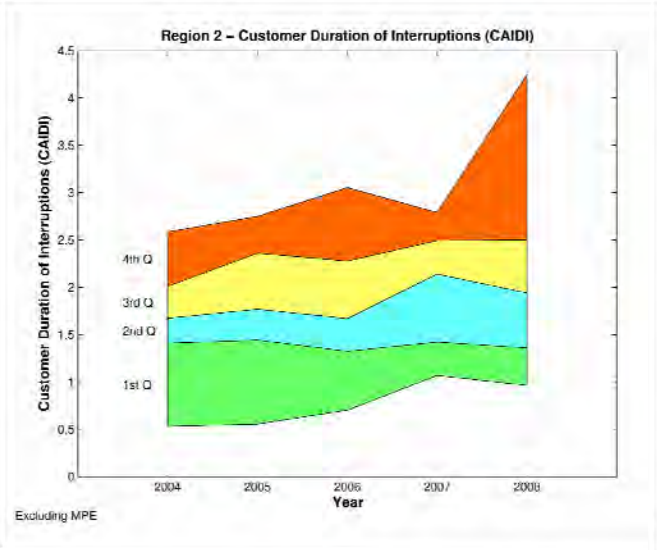
5,989,214 CUSTOMERS IN 2008

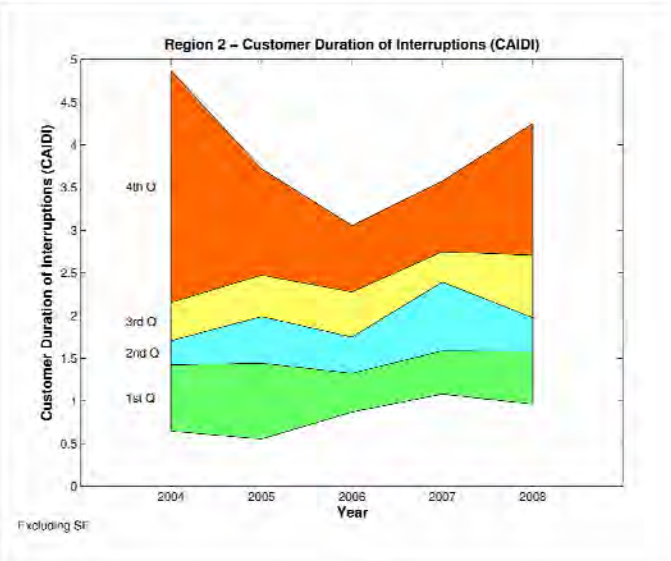
5,893,451 CUSTOMERS IN 2007

PRIMARY CAUSE	NUMBER OF INTERRUPTIONS		CUSTOMER INTERRUPTIONS		CUSTOMER HOUR INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Adverse Environment									
2008	3,554	2.2	203,454	1.2	539,137	1.1	0.03	0.09	2.65
2007	3,405	2.1	164,317	1.0	416,502	1.0	0.03	0.07	2.53
5 YEAR AVERAGE	3,476	2.2	151,156	1.0	406,315	0.9	0.03	0.07	2.69
Human Element									
2008	2,197	1.4	180,407	1.1	291,217	0.6	0.03	0.05	1.61
2007	2,203	1.3	241,511	1.5	265,879	0.6	0.04	0.05	1.10
5 YEAR AVERAGE	2,069	1.3	230,924	1.5	288,394	0.6	0.04	0.05	1.25
Foreign Interference									
2008	24,554	15.1	1,206,114	7.3	2,622,567	5.1	0.20	0.44	2.17
2007	26,780	16.3	1,261,420	8.0	2,699,211	6.3	0.21	0.46	2.14
5 YEAR AVERAGE	25,527	15.8	1,175,848	7.6	2,403,619	5.4	0.20	0.41	2.04
Total									
2008	162,469	100.0	16,515,698	100.0	51,270,337	100.0	2.76	8.56	3.10
2007	164,296	100.0	15,817,912	100.0	42,965,867	100.0	2.68	7.29	2.72
5 YEAR AVERAGE	161,175	100.0	15,385,007	100.0	44,906,836	100.0	2.65	7.74	2.92

Graph 7-M: Region 2 – Customer Average Interruption Duration Index

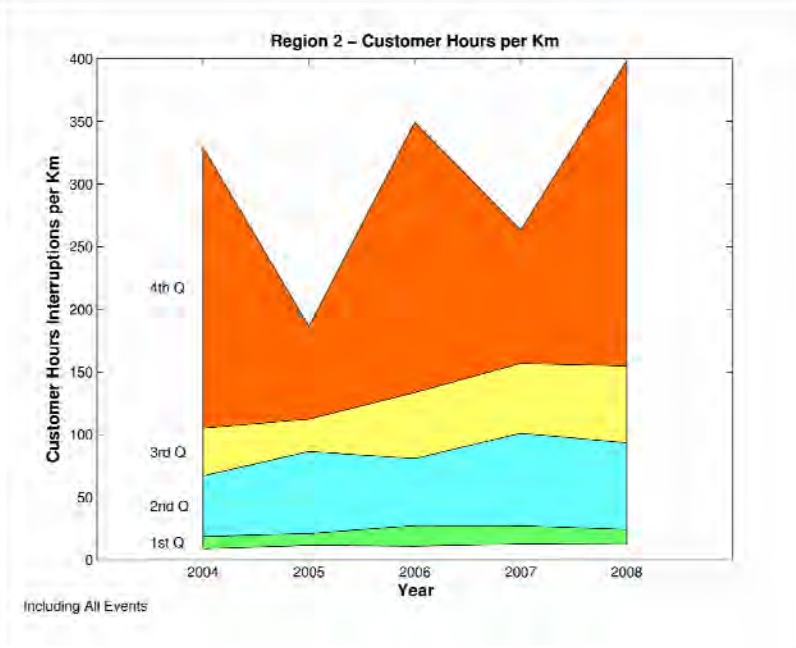


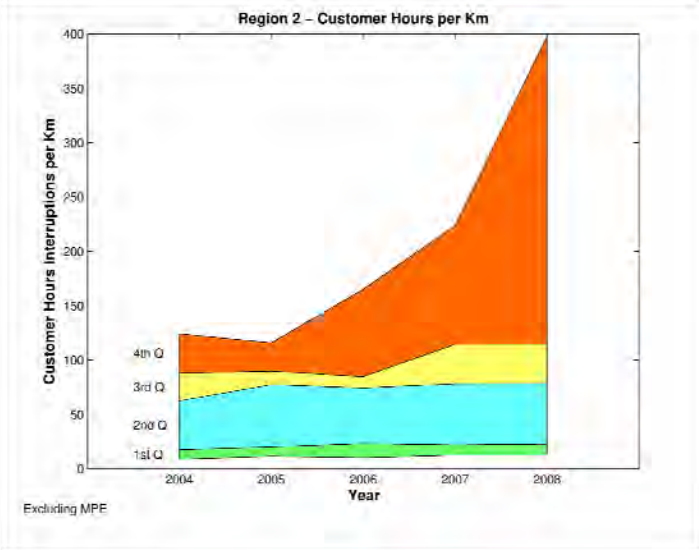


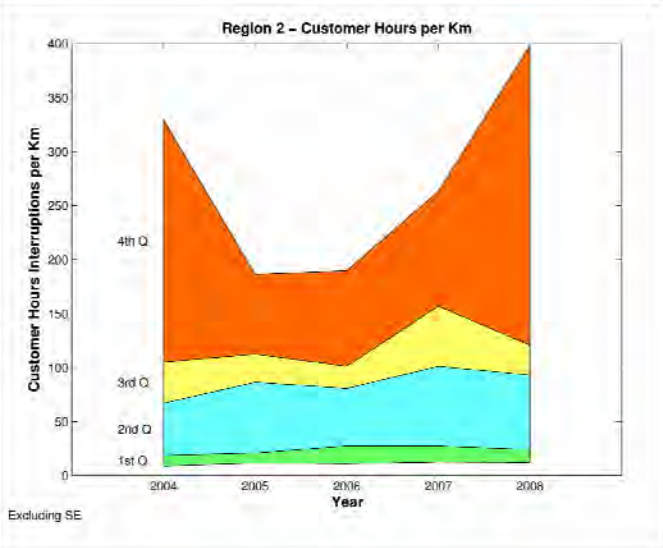


For an explanation of quartile graphs and what they represent, please go to page 6.

Graph 7-H: Region 2 – Customer Hours per KM

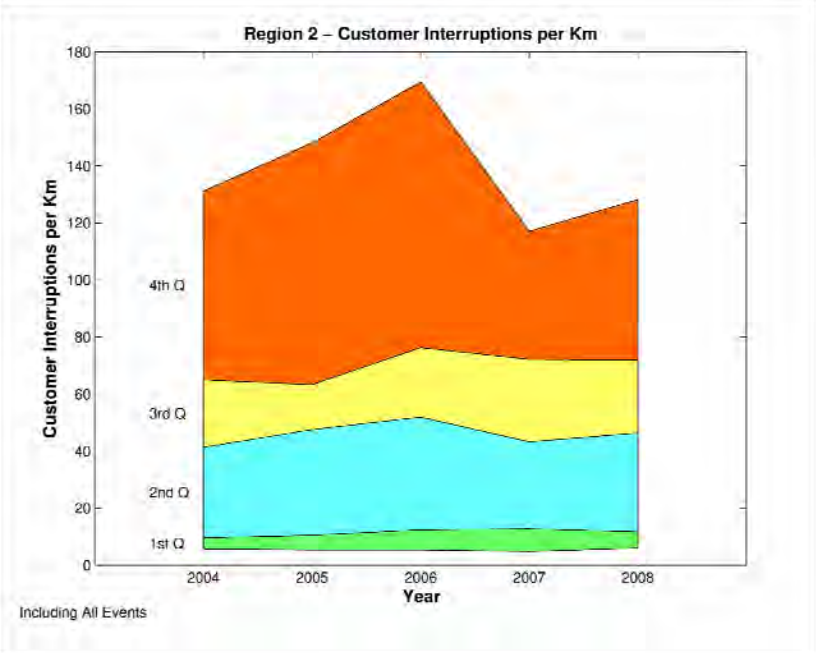




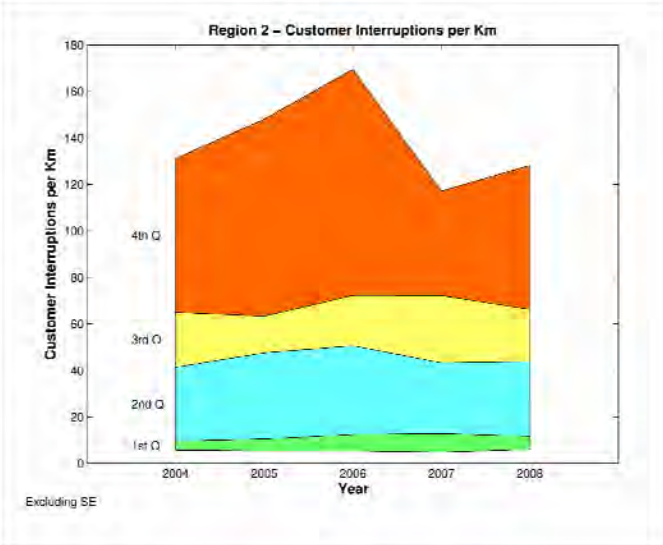


For an explanation of quartile graphs and what they represent, please go to page 6.

Graph 7-0: Region 2 – Customer Interruptions per Km

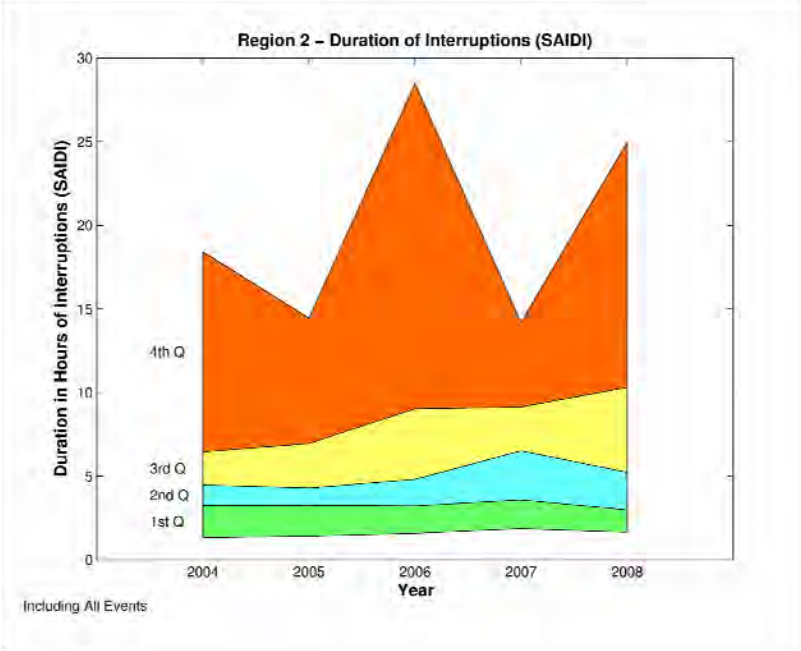


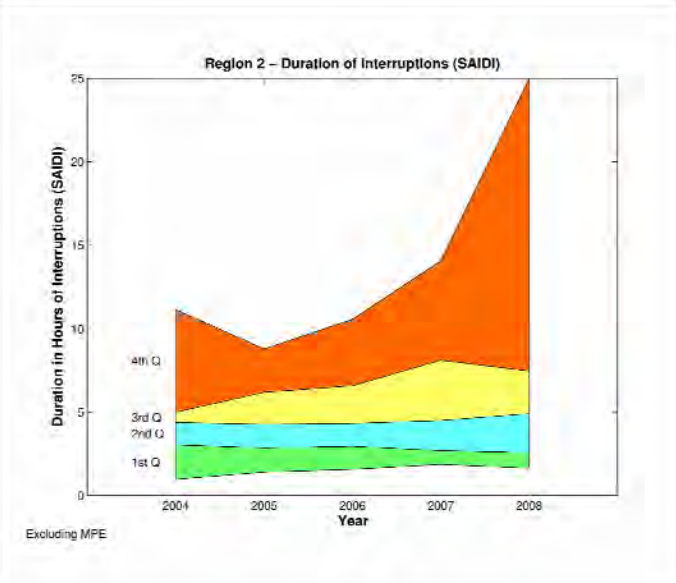


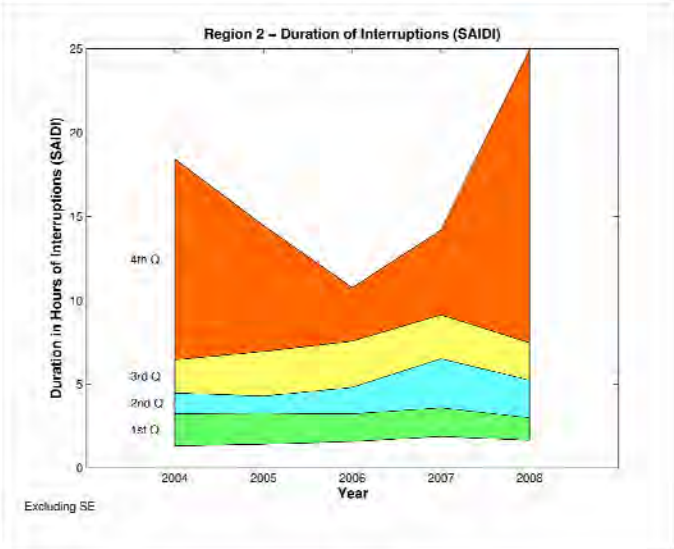


For an explanation of quartile graphs and what they represent, see explanation on page 6.

Graph 7-П: Region 2 – System Average Interruption Duration Index

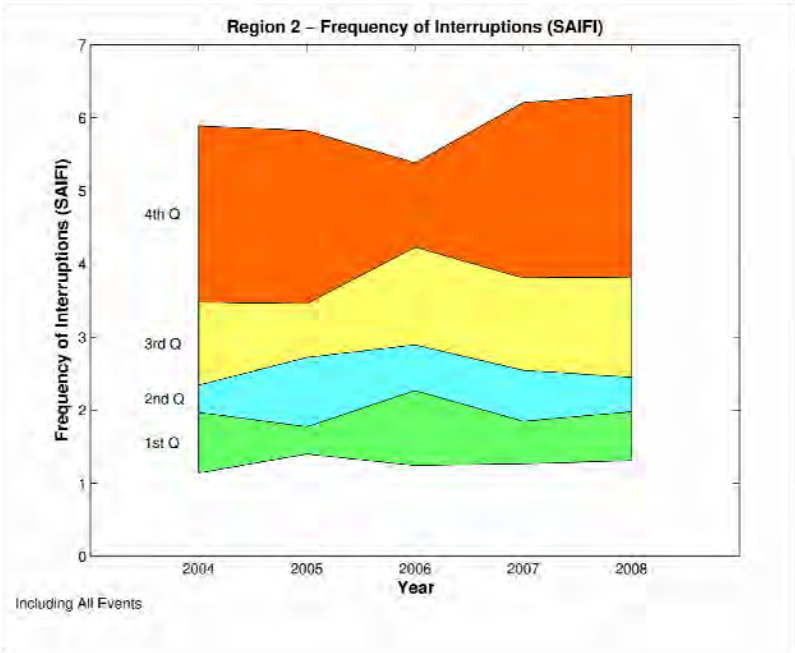


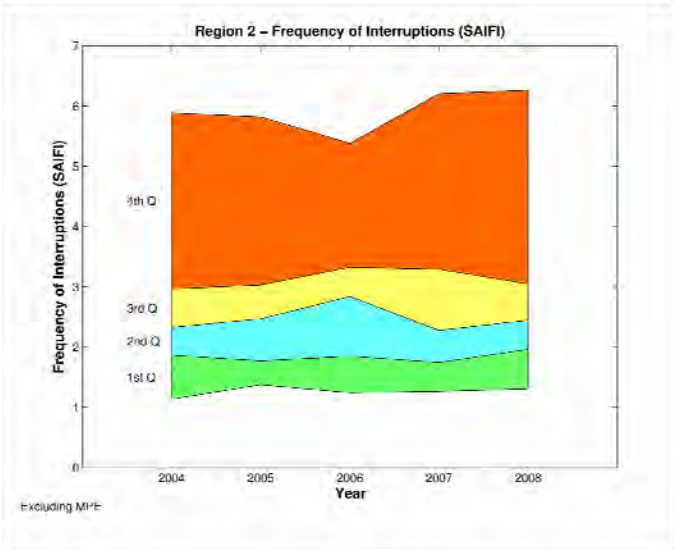


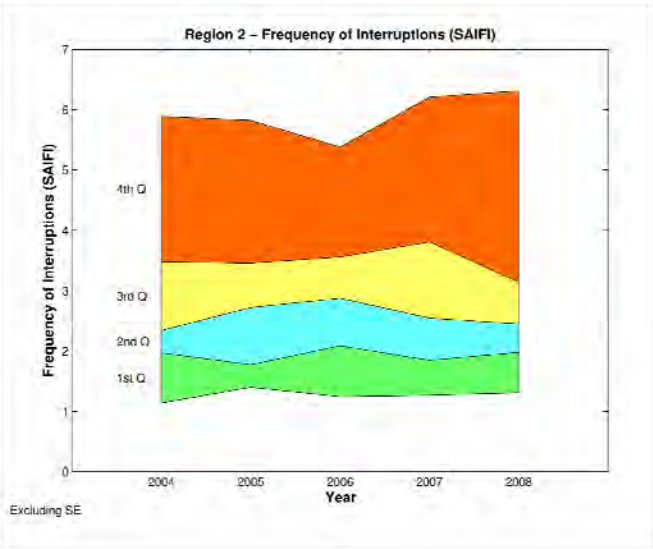


For an explanation of quartile graphs and what they represent, please go to page 6.

Graph 7-p: Region 2 – System Average Interruption Frequency Index







For an explanation of quartile graphs and what they represent, please go to page 6.

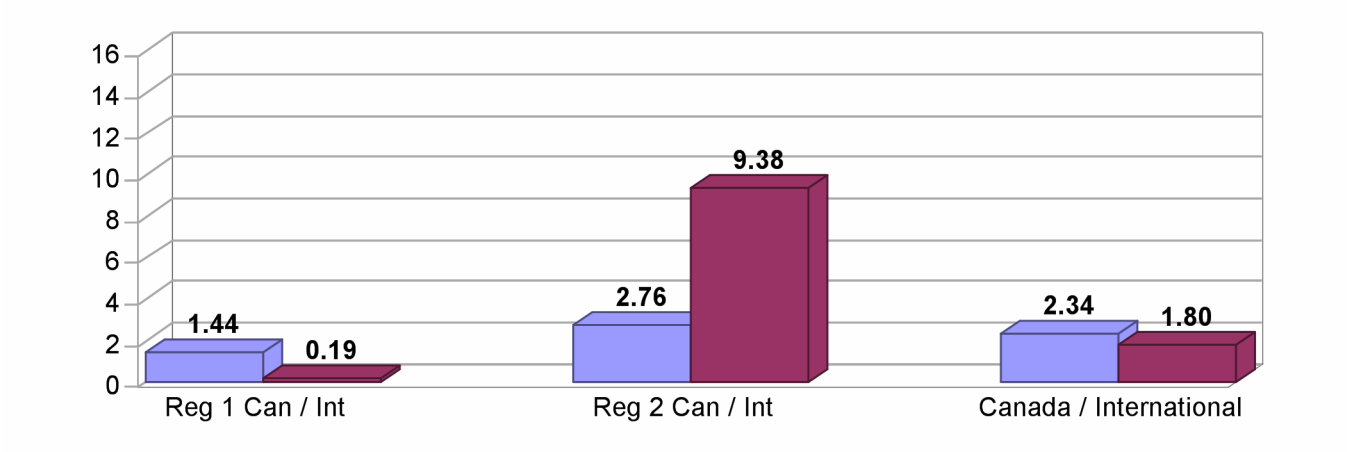
8.0 SYSTEM INDICES FOR REGIONS

8.0 SYSTEM INDICES FOR REGIONS

Graph 8.1 below shows the variations in the services indices of SAIFI, SAIDI, CAIDI and the Index of Reliability for 2008 total Canadian and International data and by regions.

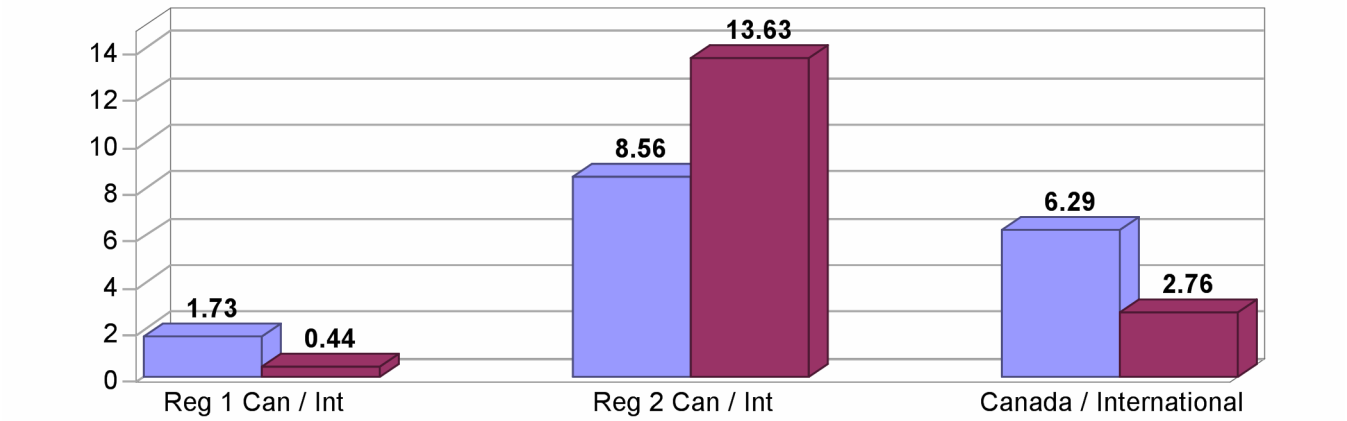
SAIFI

System Average Interruption Frequency Index



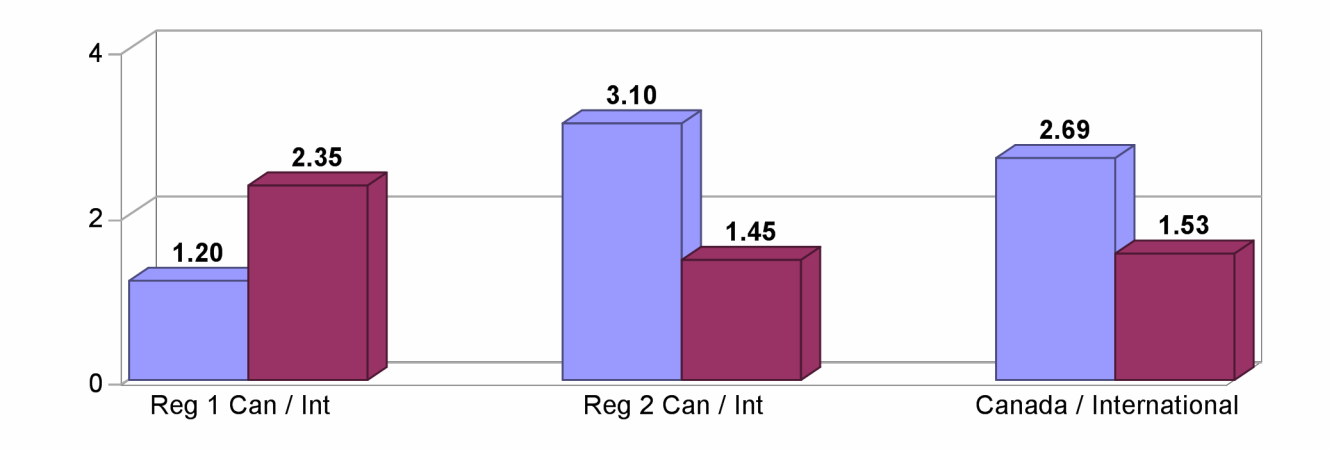
SAIDI

System Average Interruption Duration Index

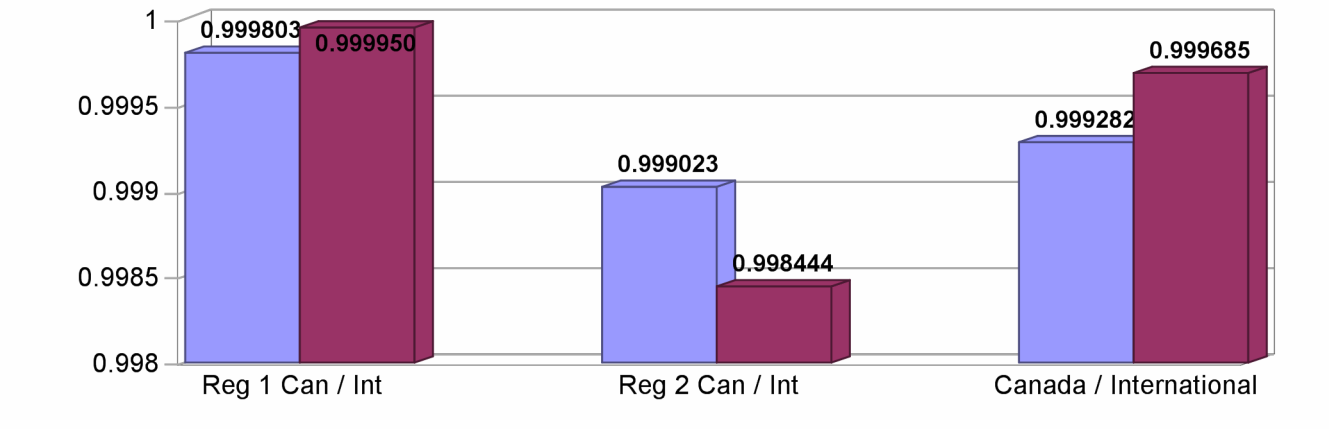


CAIDI

Customer Average Interruption Duration Index



Index of Reliability



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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

30. Ref: ExhA/Tab16/Sch1/p4
Hydro One indicates that it uses Enhanced Distribution Network Reporting and a Balanced Scorecard Approach (Corporate and Operations Scorecards). Please provide a summary of how these methods are used and practical examples of efficiencies have been achieved.

Response

The Enhanced Distribution Network Reliability Reporting provides information to the business about performance aspects of the Distribution network. It also facilitates the analysis of Hydro One Distribution equipment reliability data with data from other participating utilities across Canada. This enables to the business to identify the root causes of equipment-caused interruptions so that patterns and predominant causes for interruptions can be identified and addressed. The Enhanced Distribution Network Reliability Reporting is a relatively new mechanism that acts as an input to the business to prioritize Lines and Forestry work based on feeder reliability performance. Knowledge obtained from this Reporting system has enabled Hydro One to establish a plan to improve its reliability performance of its distribution network in the long term.

The Corporate and Operations Scorecards enable the business to monitor results by tracking measures against strategic targets, identify opportunities or issues, and apply actions. The scorecards are updated annually, presented to the senior management and reviewed monthly with senior management throughout the year. The measure results provide feedback to senior management regarding progress toward Corporate and Line of Business strategic objectives and goals. Based on these results, adjustments are made if necessary and communicated through the Lines of Business to ensure that the company achieves its strategic objectives and goals. For example, leading up to 2008, one of Hydro One's strategic objectives directed the company in the manner of protecting and sustaining the environment for future generations. In order to carry this out, hierarchical measures were created and tracked within the Corporate, Operations and Line of Business scorecards throughout 2008 that resulted in programs to achieve reduction in environmental impact of the Hydro One fleet operations.

This included the following:

- awareness program – communication to front line staff
- program to install GPS telematics to enable better utilization of its vehicles
- reduction in CO2 emissions through monitoring and reducing idling time of fleet vehicles
- implementation of plans to achieve an increase in proportion of light duty and more fuel efficient vehicles in its fleet

The scorecard measure provided high profile target goals and executive support to drive improvements in this area throughout the year.

Additional examples of efficiencies are outlined on pages 2 and 3 in the referenced Exhibit.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

31. Ref: ExhA/Tab16/Sch1/p5

a) Please provide a itemize breakout of how the savings were achieved in 2009, 2010 and 2011 as shown on Table 1. Please describe the nature of the savings recorded, the location or part of the organization where the savings are or would be found, how the savings are calculated, the projected accuracy bandwidth for future savings and the risk factors for savings non achievement. Why did O&M savings spike in 2009?

b) For the above, please provide answers for all four "savings" categories as well as for the years 2006 to 2011.

Response

a)

i. The itemize savings are in the table below.

	$ Million					
Itemize Savings	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Labour related productivity savings realized from the early stage implementation of the Smart Meter initiative, and the recently negotiated collective agreements.	3.9	0.3	2.0	11.0	6.7	3.2
IT enablement related savings - efficiencies gained through the implementation of new business processes and tools in the field to enable improved planning, scheduling and reporting.	0.7	-	-	1.7	-	-
Savings realized from the improvements/implementation of strategic sourcing initiatives.	3.2	0.5	0.5	2.2	2.3	2.1
Savings realized from the improvements of processes across the organization.	2.7	2.0	2.0	1.3	1.5	1.1
Savings realized from the implementation of Cornerstone Phase I.	-	-	-	7.2	1.3	6.3
	10.5	**2.8**	**4.5**	**23.4**	**11.8**	**12.7**

ii. The nature of the savings can be seen in Exhibit A, Tab 16, Schedule 1 pages 2, 3, and 9. They can be summarized as:

- Savings from labour related initiatives such as - the recently negotiated collective agreements, e.g. lower wage rates for newer employees;
- Savings from the early stage implementation of the smart meter project;
- Savings from the implementation of new tools and technologies used for new connections; implementation of new processes and tools in the field to enable improved planning, scheduling and reporting of work;
- Savings from outsourcing initiatives;
- Savings resulted from recent improvements in the fleet management business;
- Savings from the use of temporary headquarters for work crews e.g. reducing travel time which resulted in increased "wrench" time on the job;
- Savings from strategic sourcing initiatives, e.g. centralizing the operations for the distribution and transmission systems, and the issuance of BPOs;
- Savings from the phase I implementation Cornerstone SAP project.

In general, cost savings are realized across the organization, and may not be directly traceable to specific areas or locations. Examples of those savings are: Cornerstone phase I, labour productivity, implementation of new tools and technologies, business process improvements, and outsourcing initiatives. However, aspects of some savings can be directly traced to specific areas/section of the organization, such as:

- Customer Operations, e.g. smart meter related savings;
- Fleet Management, e.g. recent improvements in fleet's business processes;
- Supply Chain Management, e.g. issuing BPOs to ensure materials and services are available for delivery upon demand;
- Engineering & Construction Services, Stations and Forestry, e.g. reduced travel time of work crews, resulting in increased "wrench" time.

iii. The cost savings are calculated using a year over year "incremental" approach. The approach defines the further as over and above the amounts already embedded in the costs of the individual work programs.

iv. Hydro One does not analytically evaluate a "projected accuracy bandwidth" for future savings. Hydro One uses a simplified approach respecting savings management. Various savings initiatives are identified and expected targets are set. These savings are incorporated in the work programs, and their costs in the associated reductions in the revenue requirement contained in this application. Hydro One expects the various savings initiatives to be undertaken and savings targets to be achieved and manages these initiatives to this end. Regardless, the

risk associated with any shortfall in achieving these savings remains with Hydro One.

v. Please refer to Exhibit H, Tab 7, Schedule 46.

b) Please refer to the response to part a) i and ii above.

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

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

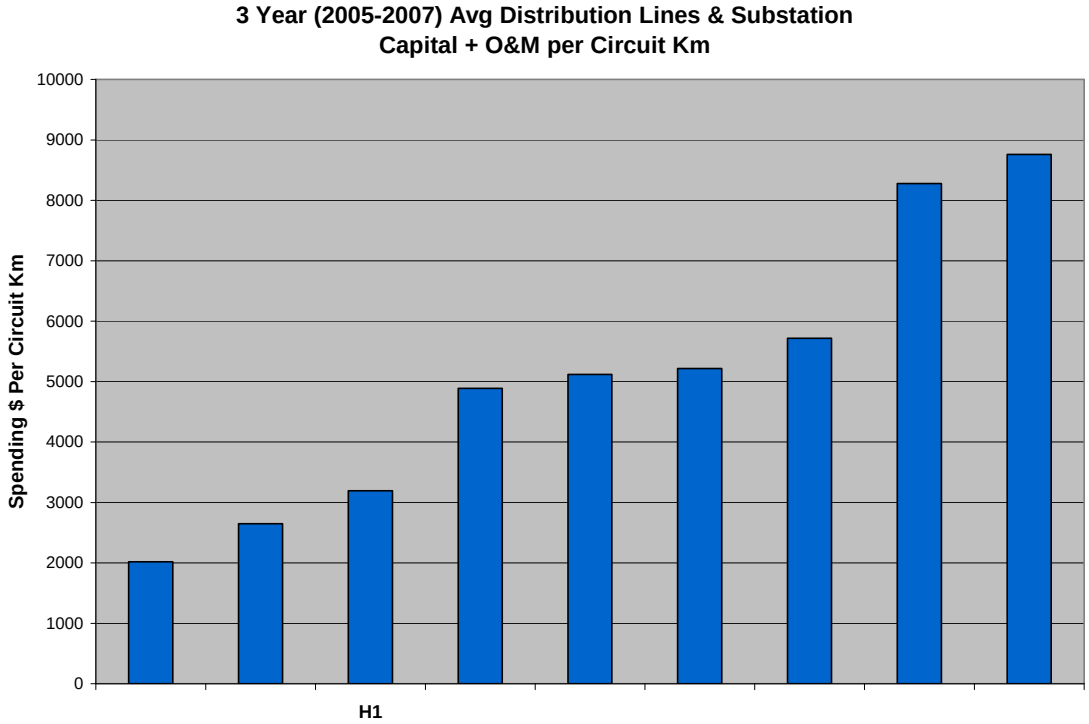
Ref: ExhA/Tab16/Sch1/p6

Please provide the Distribution Unit Costs results/targets from 2006 to 2011 including comparisons to peer utilities. In addition please report on the result of the internal comparisons referenced at lines 18 to 20.

Response

Chart 1 below shows the comparison of Hydro One's 3 year average (2005-2007) Distribution Lines and Substation costs per circuit km compared to the peer utilities.

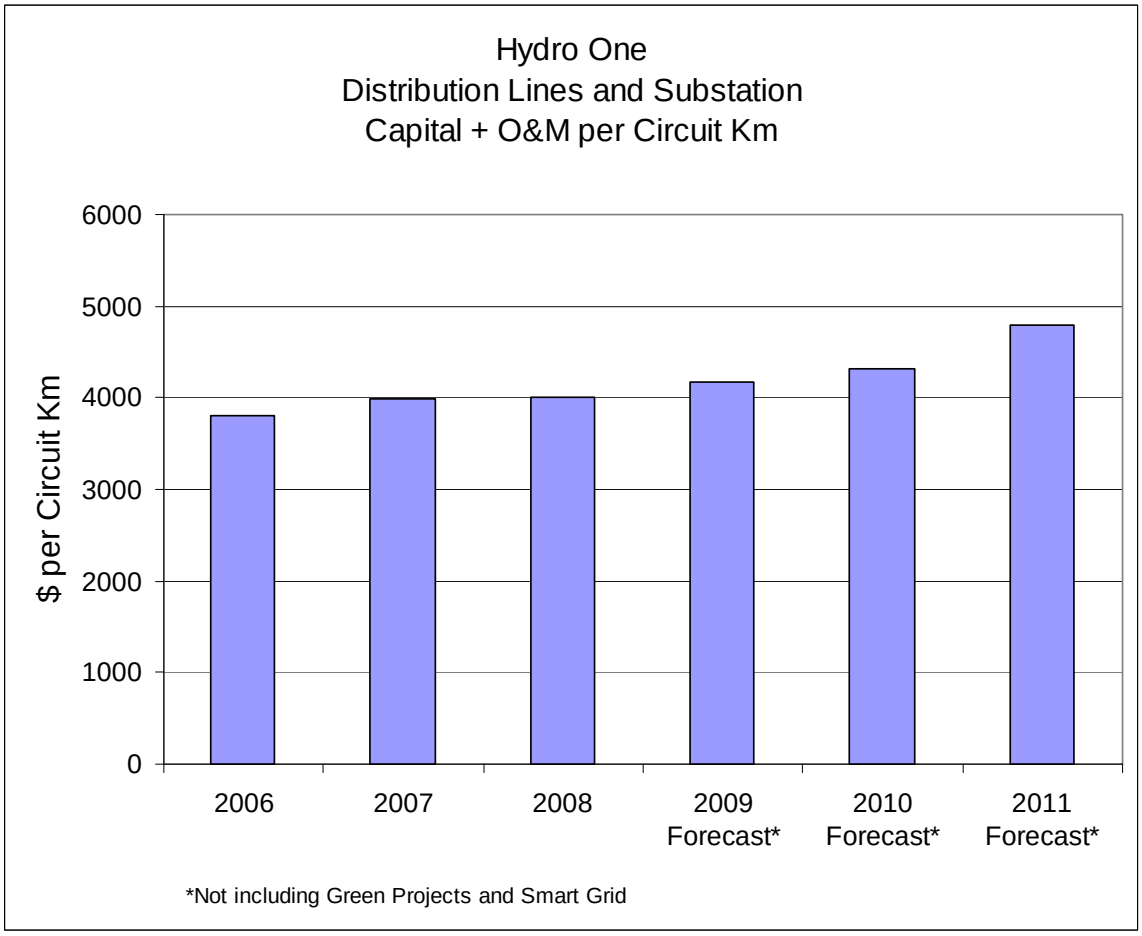
Chart 1



Data source: 2008 First Quartile Benchmark Community Study in US dollars.

Chart 2 below shows Hydro One's 2006-2008 Distribution Lines and Substation costs per circuit km and the 2009 to 2011 forecast values.

Chart 2



Costs are in Canadian dollars.

The internal comparisons have focused on the *Customer Hours per route KM, along with Customer Interruptions per route KM (Exclude Major Events,)* and we have identified various "hotspots" and better than average locations. Hydro One is also currently comparing processes to identify "Better" work practices. Distribution Lines Capital and O&M Spending per route KM data are currently being collected for comparison and improvement analysis.

Ontario Energy Board (Board Staff) INTERROGATORY #33 List 1

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

33. Ref: ExhC1/Tab2/Sch 2/p35
Sustaining OM&A – Vegetation Management: Hydro One indicates that it has prudently built its resource capability by continuing to hire forestry apprentices and contracting out line clearing work. Does Hydro One have an estimate of the cost saved by using new apprentices? In addition, what percentage of line clearing work is performed by contractors? Does Hydro One have an estimate of cost savings as a result of the use of contractors?

Response

Hydro One Distribution does not have an estimate of cost savings from using apprentices. The hiring of apprentices is a necessary step to ensure a sustainable future workforce and to reduce the resource gap of available skilled and qualified arborists to complete planned programs. Apprentices are part of the Apprenticeship Program for a period of 4 years and during that time are paid a lower rate commensurate with their experience and standing with the Company.

Contractors are called on to work when regular and Hiring Hall staff numbers do not meet program needs. In 2008, contractors completed just over 5% of the Line Clearing program. In 2009, the expectation is that contractors will complete about 6% of the program. Going forward, contractors will be relied upon to complete between 5% and 10% of the program. Contractor costs are impacted by field conditions, work requirements, and market forces. Hydro One Distribution's experience with contractors indicates their costs are comparable to in-house costs and as such, have not resulted in savings.

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

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

34. Ref: ExhC1/Tab2/Sch 2/p36
Sustaining OM&A – Vegetation Management: Hydro One indicates that it forecasts 13,500 km of line clearing and brush control for 2010 and 14,300 km for 2011. Please provide similar figures from 2004 to 2009.

Response

The following tables provide numbers of kilometers of line clearing and brush control accomplishments for the years 2004 to 2008 and forecast accomplishments for 2009.

Line Clearing	2004	2005	2006	2007	2008	2009 Forecast
kilometres	10,361	8,746	8,889	12,211	12,163	13,000

Brush Control	2004	2005	2006	2007	2008	2009 Forecast
kilometres	10,731	9,076	10,246	10,777	10,856	12,250

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

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Ref: ExhC1/Tab2/Sch 2/p37

Sustaining OM&A – Vegetation Management: Hydro One indicates that Unplanned Maintenance will increase by 1.4%, 1.4% and 2.7% respectively from 2009 to 2011. With higher levels of line and brush cleaning already in place in 2009, why are unplanned expenditures not declining?

Response

Unplanned vegetation management expenditures are expected to remain relatively steady for the 2010 and 2011 period. Significant improvements to vegetation conditions on the system are not expected until beyond the 2011 period as a shorter cycle will not be fully implemented on a system wide basis until 2014. Marginal improvements in the short term as a result of increased line and brush clearing accomplishments will be offset for the most part due to the deteriorating condition of trees attributed to the Emerald Ash Borer as highlighted in Exhibit C1, Tab 2, Schedule 2, page 37.

Ontario Energy Board (Board Staff) INTERROGATORY #36 List 1

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Ref: ExhC1/Tab2/Sch 2/p40

Sustaining OM&A – Vegetation Management: What the major reasons for the drop in Line Clearing to $84 million in 2010 and subsequent boost upward in 2011 (to $91.6 million?

Response

Hydro One's objective is to increase vegetation management accomplishments so that by 2011 the average system clearing cycle obtained is 7 years. Planned accomplishments are aligned with this direction and are the basis for the requested spending in 2010 and 2011.

Expenditures in 2009 are greater than 2010 in order to address storm hardening and reliability concerns in the central part of the Province that is characterized by dense vegetation and poor reliability performance (i.e. tree-caused interruptions). A significant motivation for this increase was the severe winter storm that occurred in the last week of December 2008 and that damaged trees and interrupted power to thousands of customers.

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

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Ref: ExhC1/Tab2/Sch 6/p4

Table 2 on this page shows a Total Corporate Shared Services cost of $174.7 million in 2010, with a Dx allocation of $123.2 million or 70.5%. Presumably the Tx allocation is approximately 29.5%. However, in the Transmission rates case, EB-2008-0272, a similar table found at Exhibit C1/Tab2/Schedule5/pg. 4 shows an amount of $260.5 million for 2010 Total Corporate Shared Services, with a Tx allocation of $66.4 or 25.5%. Presumably the Dx allocation is then approximately 74.5%. Please provide a detailed explanation for the differences in these total corporate shared services numbers for 2010 and why the allocations to Dx and Tx vary.

Response

Please note that the Interrogatory refers to the previously filed July 13th, 2009 amounts rather than the September 25th updated evidence. The corresponding amounts from Table 2 of the updated evidence are 2010 Total of $143.7M (instead of $174.7M) and 2010 Dx Allocation of $92.1M (instead of $123.1M).

Table 2 of Exhibit C1, Tab 2, Schedule 6 shows both allocated amounts and direct charges that are considered Shared Services and Other OM&A costs. For example Cost of Sales amounts are direct costs while Other Shared Services are a combination of both direct and allocated costs.

Furthermore, in the current application Customer Care is presented in its own section (Exhibit C1, Tab 2, Schedule 5) since the majority of the costs of this function support Distribution. In the EB-2008-0272 Transmission filing in Exhibit C1, Tab 2, Schedule 5, page 4, Customer Care was grouped in Shared Services and Other OM&A Costs.

Therefore, a comparison of the 2010 Total and 2010 Dx Allocation amounts from Table 2 of Exhibit C1, Tab 2, Schedule 6 with EB-2008-0272 Exhibit C1, Tab 2, Schedule 5, Table 2 is not meaningful.

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

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Ref: ExhC1/Tab2/Sch 7/p2

Table 1 on this page shows total CCFS costs from 2006 to 2011, but only shows Dx allocations for the two test years. Please provide the Dx allocations for 2006 to 2009 for all the categories in the table.

Response

Allocations to Distribution for 2006 - 2009 ($ Millions)

	Historic			Bridge
Description	**2006**	**2007**	**2008**	**2009**
Corporate Management	2.4	2.2	2.8	2.9
Finance	10.4	10.6	14.7	15.3
Human Resources	4.9	5.8	6.2	8.2
Corporate Communications	3.0	2.8	2.8	4.5
General Counsel & Secretariat	3.2	3.7	2.9	3.4
Regulatory Affairs	7.4	8.5	7.9	8.6
Corporate Security	0.8	0.8	1.0	1.1
Internal Audit	1.2	1.2	1.1	1.3
Total CCFS Costs	**33.2**	**35.6**	**39.5**	**45.2**

Ontario Energy Board (Board Staff) INTERROGATORY #39 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Ref: ExhC1/Tab2/Sch 7/p4

Corporate Management Function: Hydro One indicates that there is a lower level of executive compensation in the years 2008 to 2011 consistent with the Agency Review Panel report. Please provide the amount of the reduction in total executive compensation reflected in the Corporate Management Function totals for each year from 2008 to 2011.

Response

The impact of the reduction in executive compensation is reflected in the pre-filed evidence in the Corporate Management function (Reference Exhibit C1, Tab 2, Schedule 7, Table 2, page 3). The reductions are not specifically identified in the pre-filed evidence; however the executive salary levels are publicly disclosed.

The reduction in salary for the CEO and General Counsel position occurred in 2007. The change in the President and CEO position as well as the General Counsel position resulted in reductions of over 40% or $830,000 in total that year. The salaries in subsequent years included in the pre-filed evidence are consistent with these reductions with normal increases for escalations and employee burdens. With the appointment of a new CFO in 2009, the total salary is at a lower level than the previous incumbent.

Ontario Energy Board (Board Staff) INTERROGATORY #40 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Ref: ExhC1/Tab2/Sch 7/p8

Insurance Program: Table 4 indicates that total Insurance costs grow to $8.8 million and $9.2 million in the respective test years. These are significant increases from 2008 and earlier years. Why have costs increased to such an extent? As it appears that self-insurance costs are rising faster than insurance premiums, has Hydro One made any decisions to reduce self insurance?

Response

The increase over the 2008 amounts is largely as a result of deteriorating loss experiences and increased pricing in the insurance market.

Hydro One has not reduced the extent of self insurance. In certain instances Hydro One has increased deductibles to mitigate rising insurance premiums. When purchasing insurance Hydro one takes into consideration many factors including premium costs at various deductable/self insurance levels as well as the company's loss experience.

Ontario Energy Board (Board Staff) INTERROGATORY #41 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

41. Ref: ExhC1/Tab2/Sch 7/p12

Corporate Communications: Table 6 indicates that total Corporate Communications costs more than double from 2008 to 2010. Notwithstanding Hydro One's evidence that cites the transfer of Outsourcing Services and increased First Nations and Metis Relations efforts, has Hydro One not considered that such a radical increase in costs is really essential? What are the specific drivers of this increase from 2008 to the test years?

Response

It is not correct that Corporate Communications costs have more than doubled from 2008 to 2010 because the historical figures for 2008 were not restated for the inclusion of Outsourcing Services in 2010. If 2008 was restated to include Outsourcing Services the increase from 2008 to 2010 would be $4.2 million or 50%. The majority of the increase is related to the expansion of First Nations programs to sustain long term relationship building and negotiation with First Nations and Métis. Details of the functions performed by this group are referenced in Section 1.4.2 of Exhibit C1, Tab 2, Schedule 7. The remaining increase results from higher Outsourcing Services costs as a result of the acceleration of the negotiation and development of a new delivery system with Hydro One's existing supplier or other suppliers, as referenced in Section 1.4.3 of Exhibit C1, Tab 2, Schedule 7.

Ontario Energy Board (Board Staff) INTERROGATORY #42 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Ref: ExhC1/Tab2/Sch 7/p12

General Counsel and Secretary Function: Cost increases in this category by 40% from 2008 to the test year 2010. Please provide a table of specific drivers for this increase and why Hydro One could not strive to lower costs in this area to more reasonable levels?

Response

The 2008 to 2010 cost increase results in part from staff vacancies which reduced total costs in 2008. The 2010 amounts reflect the filling of these vacancies and the application of salary escalation. Other contributing factors that impact the 2010 budget include the records management project and higher legal costs resulting from the expansion of Hydro One's work program. These include costs for strategic partnerships, connection agreements for distribution generation and work to support regulatory-based agreements.

Ontario Energy Board (Board Staff) INTERROGATORY #43 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – Asset Management

Ref: ExhC1/Tab2/Sch 8/p3

Table 1 on this page shows total Asset Management Function costs from 2006 to 2011, but only shows Dx allocations for the two test years. Please provide the Dx allocations for 2006 to 2009 for all the categories in the table.

Response

Distribution allocations for historical years 2006 to 2008 and bridge year 2009 are shown below.

$ millions	2006	2007	2008	2009
Strategy & Business Development	2.8	2.5	2.0	3.0
System Investment	9.6	9.5	7.6	11.3
Work Program Optimization	1.6	1.6	1.1	1.2
Business Integration	7.1	6.5	5.0	5.5
Business Transformation	1.2	1.6	1.2	1.4
Real Estate & Facilities	16.9	15.7	23.1	25.4
Contract & Business Relations	1.8	0.8	0.7	0.9
Processes and Policies	0.0	0.0	0.4	0.4
Total Costs	**40.9**	**38.1**	**41.1**	**49.1**

Ontario Energy Board (Board Staff) INTERROGATORY #44 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – Asset Management

44. Ref: ExhC1/Tab2/Sch 8/p3
The total costs on Table 1 for the Bridge year do not seem to add correctly. Please correct this table or provide an explanation.

Response

The corrected table is provided below. The total cost for bridge year 2009 is $125.3 million.

	Historic			Bridge	Test		Allocation to Distribution	
Function/Service	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2010**	**2011**
Strategy & Business Development	6.4	5.9	6.3	9.7	11.0	12.5	7.9	9.0
System Investment	22.0	22.7	24.0	37.1	37.1	38.6	18.3	19.1
Work Program Optimization	3.6	3.8	3.4	4.1	4.5	4.9	0.9	1.0
Business Integration	16.5	15.5	15.9	13.4	14.2	16.3	6.7	7.7
Business Transformation	2.7	3.4	2.6	2.4	2.4	2.5	1.3	1.3
Real Estate & Facilities	38.7	37.5	41.9	48.1	57.8	59.9	28.7	29.7
Contract & Business Relations	4.9	5.1	4.9	5.9	6.2	6.3	1.0	1.0
Processes and Policies	*	*	1.3	4.6	4.5	4.6	3.5	3.6
Total Costs	**94.8**	**93.9**	**100.3**	**125.3**	**137.7**	**145.6**	**68.3**	**72.4**

* Processes and Policies was part of System Investment prior to 2008

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – Asset Management

Ref: ExhC1/Tab2/Sch 8/p5

Under Strategy and Business Development, Hydro One has indicated that it expects to design additional CDM programs as well as deliver OPA standard programs and that these costs are expected to be recovered from the Global Adjustment (so no funding appears in the test years). What amounts that are to be spent to develop CDM programs, are a part of the 2010/2011 strategy and business development function? Will these be recovered from Global adjustment? Will the additional CDM programs be funded by Hydro One ratepayers? If so, in what manner?

Response

The strategy and business development function includes approximately $1 million in each of 2010 and 2011 related to the design, development and maintenance of CDM programs. There is currently no mechanism to recover this from Global Adjustment, however, the resultant CDM programs are expected to be funded by Global Adjustment.

Ontario Energy Board (Board Staff) INTERROGATORY #46 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

46. Ref: ExhC1/Tab2/Sch 9/p4

Table 1 on this page shows total IT costs from 2006 to 2011, but only shows Dx allocations for the two test years. Please provide the Dx allocations for 2006 to 2009 for all the categories in the table. Please provide the same information for Table 2 (page 4), Table 4 (page 12), Table 5 (page 14), Table 6 (page 20), and for Cornerstone, Table 1 (Schedule 10 page 1).

Response

Please see below, the DX allocations for 2006 to 2009.

Table 1

Information Technology Summary of OM&A Expenditures

($ Millions)

	Historic			Bridge	Test	
Description	2006	2007	2008	2009	2010	2011
Sustainment	31.7	35.4	40.7	49.3	51.5	53.3
Development	3.3	2.2	1.0	2.4	5.9	6.2
Business Telecom	8.3	8.5	8.8	9.7	10.4	10.7
IT Management & Project Control	2.3	3.0	3.2	8.0	11.3	11.7
TOTAL	45.5	49.2	53.7	69.3	79.1	81.9

Table 2

OM&A Sustainment of Information Technology

($ Millions)

	Historic			Bridge	Test	
Description	2006	2007	2008	2009	2010	2011
Base IT Sustainment Services	22.5	24.4	29.1	30.0	29.1	29.5
OMS Incremental Sustainment	5.5	5.2	4.9	4.9	4.9	4.8
Other Incremental Sustainment	3.7	5.9	6.8	14.3	17.5	19.0
TOTAL	31.7	35.4	40.7	49.3	51.5	53.3

Table 4

OM&A Development Expenditures

($ Millions)

	Historic			Bridge	Test	
Description	2006	2007	2008	2009	2010	2011
Small Projects	3.3	2.1	1.0	2.2	5.8	6.2
Impact of Capital Projects	- 0.1	0.1	0.0	0.1	0.1	0.1
TOTAL	3.3	2.2	1.0	2.4	5.9	6.2

Table 5

Business Telecom OM&A Expenditures

($ Millions)

	Historic			Bridge	Test	
Description	2006	2007	2008	2009	2010	2011
Operations and Carrier Management	1.4	2.1	2.2	2.5	2.3	2.4
Field Services	1.8	1.9	1.4	1.8	2.1	2.0
Voice Services	2.4	2.0	2.4	2.5	2.8	2.9
Data Network	2.7	2.5	2.8	2.9	3.2	3.4
TOTAL	8.3	8.5	8.8	9.7	10.4	10.7

Table 6

IT Management & Project Control Expenditures

($ Millions)

	Historic			Bridge	Test	
Description	2006	2007	2008	2009	2010	2011
IT Management	2.0	2.6	2.0	5.6	8.0	8.6
Project Support and Control	0.3	0.4	1.1	2.5	3.2	3.0
TOTAL	2.3	3.0	3.2	8.0	11.3	11.7

Cornerstone Table 1 (Schedule 10 page 1)
($ Millions)

Description	**Historic**			**Bridge**	**Test**		*Allocation to Distribution*	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2010**	**2011**
Development (Total)	3.5	4.8	2.6	7.2	1.6	1.8	0.7	0.8
Development (Dx only)	1.5	2.1	1.1	3.2	0.7	0.8		
Savings (Total)	-	-	-	(9.6)	(15.6)	(27.9)	(5.3)	(8.6)
Savings (Dx only)	0	0	0	(3.3)				
Net (Total)	3.5	4.8	2.6	(2.4)	(14.0)	(26.1)	(4.6)	(7.8)
Net (Dx only)	0	0	0	(0.8)				

Ontario Energy Board (Board Staff) INTERROGATORY #47 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

47. Ref: ExhC1/Tab2/Sch 9/p11
Total IT Sustainment costs increase by 28% from 2008 to 2010. A large part of this increase is found in Other Incremental Sustainment where costs increase by 117% from 2008 to 2010. The evidence references a number of new applications that will contribute to these cost increases.
a) Please provide a more detailed explanation of how costs to Hydro One increase as a result of Cornerstone projects Phase 1 and Phase 2 move into "in-service" status.
b) Please provide a detailed explanation of why all of the new IT services listed on Page 11 are required in the test year 2010 and why there is such an escalation in the projects that contribute to the overall increase in IT sustainment costs.

Response

a) Cornerstone Phase 1 was commissioned in 2008 and introduced new SAP software and technology to the IT environment. Cornerstone Phase 2 was subsequently rolled out in mid 2009 with additional SAP modules encompassing more business functions. The commissioning of SAP as an enterprise application required additional application maintenance resources to maintain and support it. Application maintenance includes:
- design, configuration, testing, and rollout of fixes to correct system operational problems;
- technical support to business users;
- rollout and test of application patches to the SAP environment;
- overall service level operability of the SAP application with other legacy applications; and
- day to day monitoring of the SAP application suite.

b) The new IT services listed on Page 11 are:

- Enterprise Content Management (ECM)/SharePoint is an initiative that started in 2009 to provide enhanced electronic collaboration (documents / data sharing) and records management functionality in a centralized and managed environment. This initiative is needed to provide the technology to support the corporate records management / retention program. Incremental sustainment funding is required for these applications for software and user licenses, and incremental application support.
- The Microsoft Enterprise License Agreement is an existing contract to allow Hydro One employees to use Microsoft desktop and server software. Additional desktop and server software licenses and maintenance are required due to staff/headcount growth projections.
- The HP Mercury Quality Centre (MQC) is a test tool. This tool is utilized because the Bill C-198 system development lifecycle process requires tracking of business and non-functional requirements and to demonstrate their traceability through to the test scripts and defect tracking. Hydro One has experienced an increase in MQC instances and license usage with the startup of large corporate programs (Cornerstone, Smart Meters). To control costs, MQC will be consolidated in a single enterprise server and all projects will be required to share and reuse existing MQC resources and licenses.
- GIS license costs are increasing due to the incremental use of the tools throughout the company.

Ontario Energy Board (Board Staff) INTERROGATORY #48 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

48. Ref: ExhC1/Tab2/Sch 9/p12
Small Projects costs quadruple from $2.7 million in 2008 to $10.4 million in the test year. Please provide additional rationale for the need to increase small IT projects to this extent over 2 years, including detailed reasons for the need for each project and what benefits each project is expected to deliver.

Response

In 2008 and 2009, there were lower than historical spending levels for small projects mainly due to the focus on the core Cornerstone program. Work was deferred, where possible, until:

a) personnel returned from the project and to their normal posts (fall 2009);

b) SAP was installed and stabilized with the replaced legacy systems no longer in use for core business operations.

Projects in the test year include:

Item	Project	(M)
1	Application rationalization	$1.4
2	IVR Upgrade	$0.5
3	Customer Care/Billing application modifications	$1.2
4	Supply Chain process improvements	$1.9
5	CRM for Distributed Generators	$0.3
6	Enterprise analytics and reporting	$2.1
7	Performance Management	$1.5
8	GIS Application Upgrades	$1.5
	2010 Small Projects Total	$10.40

1. Application rationalization $1.4M – this work will analyze the current software applications and databases employed within Hydro One and take action to reduce and rationalize where possible. It is expected to result in a simpler and more cost effective IT environment. It will also allow for further productivity gains by

making more data available across the enterprise (for example, via SAP) instead of in stand-alone databases and applications.

2. IVR Upgrade $0.5M – the customer facing interactive voice response (IVR) system requires an end-of-life upgrade to keep it vendor-supported.

3. Customer Care/Billing Application Modifications $1.2M – this entails changes to the customer billing system per regulatory requirements such as rate changes. System modifications to accommodate the harmonized sales tax are also planned for 2010.

4. Supply Chain process improvements $1.9M – this work will take the industry standard processes implemented in Cornerstone Phase 1 and build on this work to improve the business processes for reduced cycle times and improve material delivery fulfillment. It will also ensure we meet new Provincial procurement guidelines and maintain an optimized enterprise solution during implementation of all the changes.

5. Customer Relationship Management (CRM) for Distributed Generators $0.3M – this work will optimize business processes and the necessary software tools to manage the large volume of distributed generator applications. The result will allow for more effective management of generator applications and will decrease the overall processing times to align with required timelines.

6. Enterprise Analytics and Reporting - $2.1 – this work will add additional information sources other than SAP to the Business Intelligence/Business Warehouse system implemented as part of Cornerstone Phase 2. The information from additional applications and databases will enhance the availability and quality of information to support work program decisions, prioritize work, and optimize investment decisions. The consolidated reporting environment will allow decommissioning of legacy applications and databases.

7. Performance Management - $1.5M – this work is to define further diagnostic metrics to assess the corporate performance in the areas of SAP-enabled processes. This work is required to measure and manage the efficiency of our work force in utilizing our SAP investment. The measures will be designed to identify problems that affect the execution of the process as designed and identify the needed improvements.

8. GIS Application Upgrades - $1.5M – includes version upgrades and patches to our existing GIS application and database components to maintain it in a vendor-supported state.

Ontario Energy Board (Board Staff) INTERROGATORY #49 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

49. Ref: ExhC1/Tab2/Sch 9/p15
Please provide a copy of the report of the Shpigler Group report on the benchmarking of the costs of services provided by Hydro One Telecom.

Response

Please see Attachment 1.

Hydro One Telecom Inc. Services Review and Benchmarking

Prepared for:



Prepared by:



May 2008

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Executive Summary

Over time, nearly every electric utility has established some form of telecommunications capabilities in support of their normal operations. As the demands of operating an electric utility grow in complexity, many utilities have built extensive telecommunications transport networks in support of such applications as teleprotection, SCADA, telemetry, and others. As demands on these telecom networks have grown, the capital resources allocated to them and the staff that oversees their operations has grown in size and scope. As such, it is often useful to perform periodic studies to compare the efficiency of such telecom units to a group of similar utilities to ensure that existing cost levels are in line with industry norms and to identify emerging best practices. Hydro One Networks operates as the dominant provider of electricity within the province of Ontario, with 97 percent of the transmission system and about one-third of the province's distribution system, spanning 75% of the province. The transmission network involves some 28,600 kilometers of lines and the distribution network supports over 1.1 million electric customers across rural Ontario. Hydro One Networks is the largest operating subsidiary of Hydro One Inc., which is wholly owned by the Province of Ontario. Hydro One, Inc. operates four distinct business lines: Hydro One Networks (transmission and distribution across the entire province), Hydro One Brampton (distribution network within the City of Brampton), Hydro One Remotes (electric operation in the Northern Ontario region), and Hydro One Telecom (fiber optic business).

Hydro One has an extensive telecommunications operation in place to serve its core energy business. The telecom group reached a point in its development where their capabilities had the potential to add value as a shared service in conjunction with the commercial telecommunications operations. The telecommunication group’s expertise in operating a sophisticated telecommunications network to commercial availability standards on a daily basis, its knowledge of the commercial market and of the special needs of electric power systems made the outsourcing of network and vendor management appealing. Hydro One Networks Inc. (HONI) determined that by having Hydro One Telecom (HOT) manage network control and third party telecommunications

contracts, they had the opportunity to control costs and optimize their network monitoring.

Even as the telecommunications group supports the communications needs of Hydro One's Network, there is an ongoing desire to better understand the competitiveness of the group's operations. More specifically, HONI chooses to benchmark the performance of its telecommunications group to determine how it compares to peers with respect to operating efficiency. The Shpigler Group was engaged in 2005 and 2006 to research and analyze this issue by evaluating the group's performance as defined in the Service Level Agreement (SLA) and benchmarking the activities against similar operations. We have been re-engaged in 2008 to review the SLA for 2009-2010, to evaluate the competitiveness of HOT for the past year and assess the projected competitiveness for the new SLA duration. The following analysis is based on updated benchmarks from the 2006 report and compares expected future performance against the same peer group.

A close review of the 2009-2010 SLA to the 2007-2008 SLA indicates that there were no material changes between the two SLAs except for the increase in the predefined work scope and wage and benefit labor increases. The similarity of the two SLAs allows a forward looking comparison to be made after verifying that the peer utilities were proportionately stable, which they are. Therefore, we determined that the updated benchmarking data along with our understanding of the projected changes for each utility would allow us to estimate the relative performance of utilities for the 2009-2010 SLA and reach a conclusion.

In our opinion, the unique voltage potential of a power system has created the need for electric utilities to create their own telecommunications entities that can isolate and insulate the telecommunication infrastructure, which protects communications during electrical disturbances. Protecting electrical equipment requires sophisticated systems that need to communicate between substations and power plants. The need to isolate electrical and telecommunications facilities for safety and service reliability has supported the development of large utility telecommunication entities. Even with fiber

optic channels negating some interfacing concerns, the need for end electronics equipment to interface with optical equipment at risk to voltage surges still exists. Network operation centers of public and private telecommunications companies rarely have the experience or knowledge necessary to manage a power systems telecommunication system. Therefore, for benchmarking purposes, we determined that the most meaningful and comparative data would need to be obtained from similar Canadian utility telecommunication entities.

Through this engagement, our efforts have centered on evaluating the existing service level agreement with HOT, evaluating the performance of HOT as compared to the defined deliverables and industry standards, analysis of the cost structure, and an audit of third party pass-through contracts and charges. The benchmarking data was collected from three comparable Canadian utilities and compared to results for the past year. The other utilities studied were Manitoba Hydro, Hydro Quebec, and BC Hydro; they were chosen for their similar telecommunications needs and service territories. The report and our conclusions are based on primary research from interviews, secondary data collection and benchmarking comparisons between these three utilities. In addition, we have included insights gathered from other utilities regarding “best practices” in network monitoring.

Analysis of HOT operations was centered on the following:

- SLA applicability to present services provided
- SLA deliverable performance
- HOT cost breakdowns
- HOT third party contract management, costs and savings
- HOT Network Management services benchmarking

Through interviews with top level management, detailed data analysis, and review of third party invoice handling practices and benchmarking, our findings are as follows:

- Benchmarking results continue to indicate that the HOT Network Operation Center is comparable to the other Canadian utilities' 24x7 telecommunication operation centers and the overall Service Level Agreement is at market.
- The 2009-10 Service Level Agreement was reviewed and is similar to past agreements with the addition of some carrier management dealings.
- All reporting as specified by the Service Level Agreement was reviewed and was found to be complete.
- In the current benchmarking exercise the analysis included a review of costs, projected growth and shift coverage. The results of this exercise indicated that HOT is providing coverage similar to the other utilities that provide 24x7 services.
- HOT's competitive cost position, which existed from 2005-2008, even when increased for labor costs and scope changes in 2009-2010 will maintain a lower or competitive cost of service when compared to other network monitoring operations.
- Benchmarking also indicates that the shared services concept has provided an advantage over other methods. HOT needs a fewer number of operations positions than other utilities that manage a power system-only workload, even as the amount of work and size of the telecommunications system increases.
- Adjusting for future assumptions, HOT maintains a lower or equivalent cost of service with the comparator group
- The pass-through costs for third party handling are in line with original billings from the third party. A review of invoices supported the conclusion that third party costs are passed through directly to HONI without markup.
- The HOT charge for handling third party contracts is significantly less than what they have been able to save in contract re-negotiations. Having a dedicated unit focusing on the telecommunications-related issues (like bill accuracies) coupled with the combined purchase power of a larger entity has proven beneficial to not just the HONI staff, but also to the efficiency of the telecom functions.
- Leveraging the commercial knowledge and acuity of the HOT staff continues to benefit the entire corporation.

- We believe that the benefits of a commercial telecommunication approach of the HOT staff coupled with the power system knowledge is an effective tool in extracting value for both HONI and HOT in their respective areas of responsibilities.

Our full report which includes some operating recommendations is included below.

Background on The Shpigler Group

The Shpigler Group is a strategy management-consulting firm focused on the telecommunications and technology sector. The Shpigler Group works with utilities, municipalities, telecom service providers, and infrastructure and technology developers in solving complex issues involving strategic assessment, market analysis, business case development, economic evaluation of network design, and competitive and partnership assessment. The Shpigler Group has been heavily involved in the utility telecommunications industry, dealing with operational and strategic issues involving networks with fiber, wireless, power line, satellite, microwave, and other access approaches.

David Shpigler, President of the firm, brings an extensive background in strategy consulting to companies in high technology industries. Prior to founding The Shpigler Group, he was with Cambridge Strategic Management Group, Dean & Company, and Accenture, all leading strategy consulting firms focused on serving the telecommunications, high technology, and utility industries. In addition to his work with The Shpigler Group, David has served as the Director of Research for United Telecom Council, developing research studies for the utility telecommunications industry. He has also served as Adjunct Professor of Operations Management at Berkeley College. David has a B.S. in Business Economics from the University of the State of New York, Albany and an MBA from the Graduate School of Business at the University of Chicago.

Heather McGinnis, an Associate at the firm, brings a deep understanding of project management, production scheduling and process improvement. Before joining the Shpigler Group, she ran a business services and manufacturing firm in Northeastern Pennsylvania. She has extensive experience in business development, customer relationship management, and IS design and implementation. Ms. McGinnis graduated summa cum laude from Pennsylvania State University with a BS in Management, Information Systems, and International Business and recently earned her Project Management Professional (PMP®) certification.

Project Methodology

Some choices were made in the commission of this benchmarking report. Initially, the choice was made to focus on a smaller number of utilities and conduct detailed research gathering with each rather than try to generate higher-level surveys with a larger group of utilities. Even though the quantity would have been more statistically significant, we felt it might generate questionable findings. Next, the specific utilities targeted were chosen for the nature of their operations; that is, utilities with some critical mass with respect to overall service territory were targeted. Although the original desire was to benchmark cost positions of utilities relative to one another, it became apparent that to do so would lead to some questionable conclusions because the cost positions are driven by a number of completely unrelated and in some cases uncontrollable factors. For example, differences in accounting practices – like burden rates – can skew results, shielding us from gaining a complete understanding of true operational efficiency. As a result, the benchmarking study was based on headcount positions at each of the utilities as they related to network monitoring work output levels. Finally, since each utility profiled featured a very different organizational structure, we embarked to benchmark the job functions rather than individual work groups.

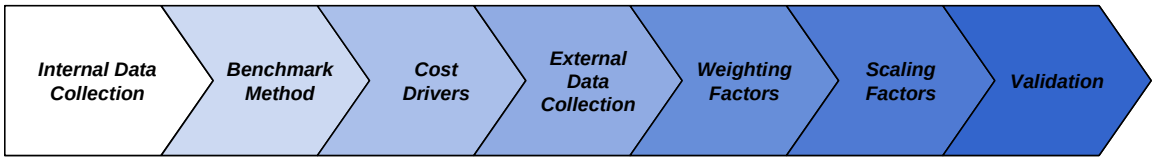
We believe that the information gathered in this report should offer a strong perspective for the desired benchmarking effort. Ultimately, the reader should be cautioned that the data collected and the resultant conclusions within this report represent important findings regarding overall trends, but with error margins due to the lack of complete "apples-to-apples" comparisons. Furthermore, each of the utilities profiled in many cases shared the fact that their operating practices are in flux, with many of the practices currently undergoing changes. As a result, the conclusions reached as part of this report reflect a current status of a "moving target" in many cases.

In order to thoroughly understand the services and charges for services from HOT to HONI we needed to ensure that we established a methodology that supported the key

goals of the project. The key steps that we needed to account for as part of the process included:

- Analyze the 2009-2010 Service Level Agreement (SLA) to determine required services and reporting
- Assess deliverables required by the SLA
- Analyze major cost component areas
- Collect data from key process owners
- Perform review of third party pass through costs
- Determine appropriate method for performing benchmarking
- Collect data from benchmark utilities
- Calculate weighting factors
- Perform scaling function to address discrepancies in volumes
- Compare results across benchmark companies
- Refine analysis as needed

In order to account for each of these issues, we followed a methodology involving a seven-step plan:



Step 1 – To start, we conducted initial interviews with HONI and HOT staff to understand key processes, work functions, and output levels. In doing so, we were able to get a basic understanding of the tasks at hand and to understand the HOT- HONI relationship, organizational structure and work output. After initial discussions with HOT and HONI, it became apparent that the key operational function performed by HOT for HONI was the Network Monitoring function. All other functions found in the utility telecommunications groups (planning, engineering, construction etc.) were part of HONI, and, as result did not require benchmarking.

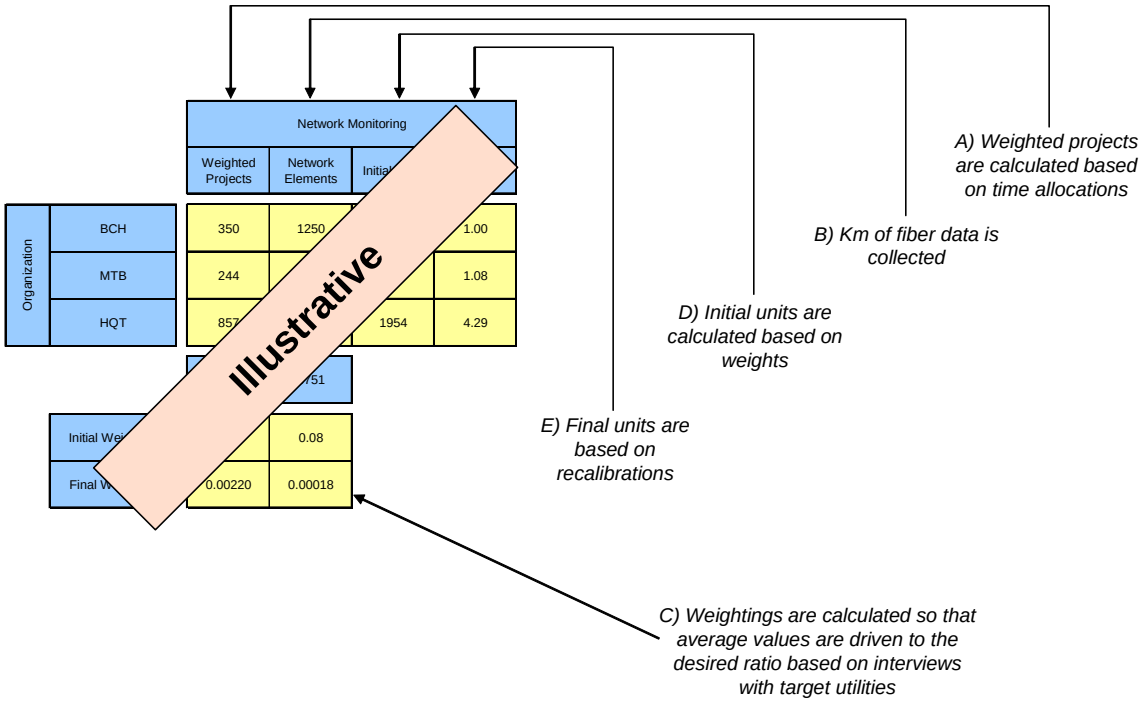
Step 2 – Next, it was necessary to develop a methodology for the overall benchmarking effort. Given that each utility had a different amount of work that it generated on an annual basis, applicable cost drivers needed to be established for each organization. Due to the potential differences in labor rates, cost allocation methodologies, and burden factors that are outside the control of HOT, we embarked on an effort to determine efficiency levels based on full time equivalents (FTEs) rather than on pure dollars.

Step 3 – Through interviews, a set of specific definitions was established for each activity area that was common to all electric utilities interviewed:

- Ensuring physical and logical security of network
- Conducting remote fixes of network when available
- Major alarm investigation
- Client services associated with network monitoring
- Monitoring technology platforms within the network

Step 4 – Having set up the overall methodology to process information and to structure the study, the next effort now focused on conducting detailed direct interviews with each of the targeted utilities. Our desire was to target as many Canadian electric utilities that would offer as fair a comparison to Hydro One as possible. Given that there is no utility that features a fully comparable mix of customer count and service territory size, it became apparent that a precise match would be impossible. However, we embarked on an effort to identify the most comparable utilities that would offer meaningful benchmarks based on having a service territory of some substance, a critical mass of customers, and some portion of the network in rural/remote areas.

Step 5 – Once the data was collected from each utility, we needed to calculate appropriate weightings to apply to work outputs in order to make cross-company comparisons. To illustrate the methodology on which these weightings were developed, the following is an example of how we approached the subject on calculating weighting factors:



In using weighting factors, certain issues need addressing:

- *Issue A* – First, we gathered data from each of the benchmark utility telecommunications groups related to the commission of project related work. This factor was determined to be significant in determining work load for a network monitoring function. We arrived at a measure of "weighted projects" by determining point values for large projects (25 points for projects lasting over 6 months), medium projects (4 points for projects lasting 6 weeks to 6 months), and small projects (1 point for projects lasting under 6 weeks). We then multiplied the point values for the number of projects and arrived at a weighted project value for each benchmark utility.

- *Issue B* – We also identified the number of managed network elements as a key factor involved in determining network monitoring workload. Accordingly, we collected information about the network elements in each benchmark utility's telecommunications network.

- *Issue C* – Next, we needed to arrive at a methodology to calculate the combined effects of both factors of workload under consideration – projects and network elements. Based on interviews with each of the utilities as well as prior experience in the field, we concluded that these factors impacted workload equally. However, the difference in scale resulted in an inability to simply combine the totals of each measure. To normalize these factors, we used weighting multiples to arrive at an expression of relative workload that maintained the desired 50/50 split in impact.

- *Issue D* – We multiplied the benchmark results for weighted projects and network elements by the weighting factors to arrive at preliminary measures of relative workload for each of the utility telecommunications unit.

- *Issue E* – Because the work units are based on a somewhat arbitrary scale, the resultant numbers are meaningful when compared against one another, but not necessarily in isolation. In order to process the information using a more manageable scale, we reduced each of the work load unit counts by an equivalent coefficient so that the utility with the lowest work load among the peer group would be assigned a value of one and all other utilities would be indexed off of that value.

Step 6 – Calculating the relative workloads of each group required a scaling function be performed to compare differing levels of activities at equivalent rates. We know the total number of people performing various job functions at each of the utilities based on the interviews conducted. Then, based on the procedures in step # 5, we also know the amount of work conducted by each group. With these two pieces of information, we can calculate unit costs – the headcount per work unit – and make comparisons between utilities. However, doing so would lead to an error in methodology. Certainly, we are aware of the existence of scale efficiencies – the ability of organizations to perform functions at higher efficiency levels as they grow in size. To illustrate this concept, consider two utilities performing a certain job function at the same unit cost, but one

utility is substantially larger in size than the other. This shows that the smaller utility operation is more efficient because it is able to achieve the same unit cost without the benefit of scale efficiency. To operate at the same efficiency level, the larger utility would need to leverage its size to amortize some of the fixed costs across the larger base of operations and achieve a superior cost position. In order to account for this issue, we then developed calculations concerning scale curves.

Step 7 – Once the data was collected from each utility and comparisons were made, a number of data points appeared to show questionable results – and were validated through additional interviews.

Network Monitoring

Workload: The complexity of HONI's network demands a high focus on network monitoring to support successful ongoing operation of the telecom transport network. Based on research into the amount of work output supported by each network-monitoring group, we calculate that HOT supports the second highest work output among the peer group based on work supporting HONI:

	Network Monitoring			
	Weighted Projects	Network Elements	Initial Units	Final Units
Hydro One	1,039	4,378	1,591	2.40
Manitoba Hydro	285	2,990	662	1.00
Hydro-Québec	857	13,462	2,555	3.86
BC Hydro	610	1,300	774	1.17

Initial Weighting	1	0.13
Final Weighting	0.00151	0.00019

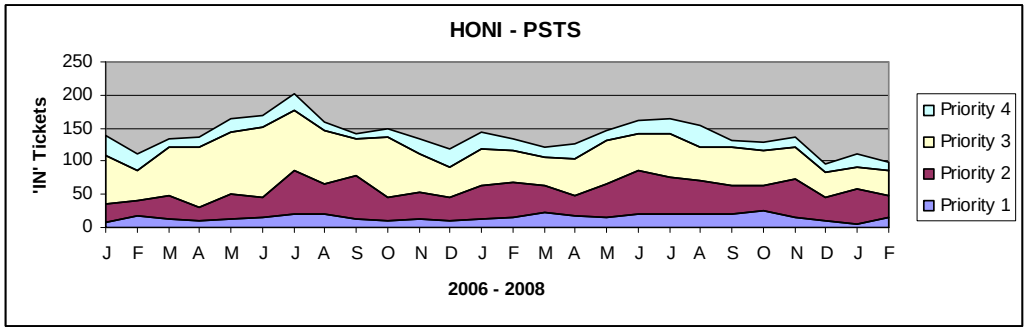
Cost Positions: We calculate that the cost assumed by HONI as a result of HOT operation of the network monitoring the telecommunications network is based on supporting the equivalent of 15.09 FTEs. We conducted a similar analysis for each of the benchmark utilities and further adjusted the scale so that headcount equivalents were based on the average workloads in the industry. Based on this exercise, we calculate that HONI's operation of the network monitoring function is still comparable to the peer group. As a point of reference, the HONI's FTE count of 13.70 compares with an equivalent FTE count of 10.77 for Hydro-Québec, 12.13 for Manitoba Hydro, and 18.53 for BC Hydro. This shows that HONI and Manitoba Hydro are within 1 headcount of maximum industry efficiency standards.

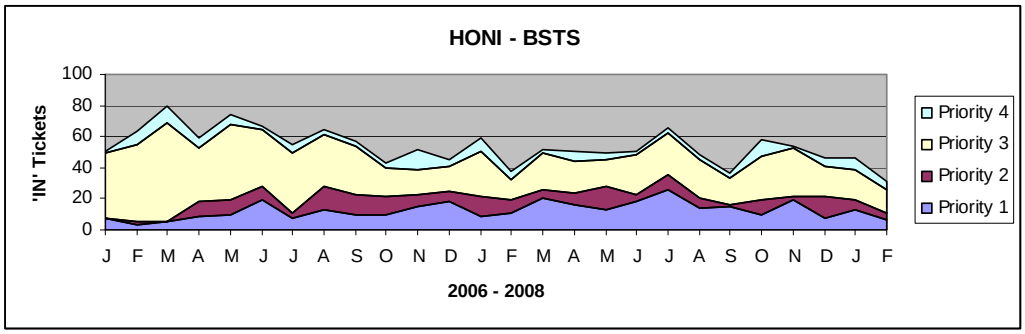
	FTEs	Work Units	Unit Cost	Comparable FTEs	FTEs in Excess of Industry Average	% Difference from Industry Efficiency
Hydro One	15.09	2.40	5.40	13.70	0.97	7.66%
Manitoba Hydro	7.00	1.00	12.97	12.13	-0.60	-4.70%
Hydro-Québec	16.81	3.86	3.36	10.77	-1.96	-15.40%
BC Hydro	12.00	1.17	11.09	18.53	5.80	45.61%

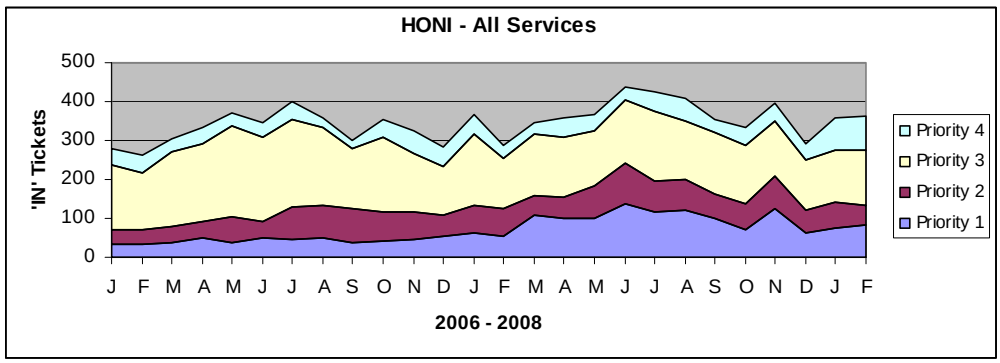
The breakdown of the HOT budget indicates that costs continue to be driven by the labor portion of the budget due to the demands of the required 24 x 7 network management coverage. The average increase in wages of 5.7% accounts for the only increase in the HOT budget for 2009 and 2010 aside from an identified incremental workload increase of $139,500, or 14.34%, as required by HONI to cover an additional carrier/vendor management services. The total cost to HONI is strictly labor-related as all third party bills for maintenance and equipment are directly invoiced to HONI. Any and all replacements and additions are justified through analysis. The only opportunity for HOT to increase efficiency is from the labor portion of the budget, which it does not control because the labor force is represented by a group agreement with HONI. HOT's efficiency has improved as can been seen by the additional workload they've absorbed in the past few years without increasing headcount Technology continues to push more work into the Network Operations Centers with self-diagnosing field equipment, alarms, and remote servicing capabilities. As equipment replacements at HONI continue, workload has increased for HOT.

Even with the cyclical increases in alarms in the summer months, the overall number of tickets has decreased for both the PSTS and BSTS groups over the last two years. The All Services graph includes the alarm work for HOT system as well. The overall trend here, however, continues to indicate a growth in alarm activity.

January 2006 – February 2008







SLA Analysis

There are several key components in Service Level Agreements that are critical to the unique operational requirements of electric utilities when transferring responsibilities to a shared services organization. The key elements of developing a successful shared services understanding are as follows:

- *Service Level Agreement*: Planning and preparation for service provisions and service level agreements should be conducted once a year by both the shared service organization and the individually affected business units
- *Monthly Billing*: Costs for the provided services are charged to each client on a monthly basis via internet application which in turn files the invoice into an accounting system
- *Detailed Performance Reports*: A variety of monthly detailed charge-out reports are created which identifies costs charged to the client organization. Monthly reports on detailed charges are compared against previous work and standard marketplace costs
- *Markup for Third Party Costs*: Typically, shared services organizations are treated as a cost center with no mark up included unless specifically agreed upon in the affiliate transactions related regulations
- *Key Performance Metrics are Established*: Establishing and agreeing upon clearly defined performance metrics is critical to the effective functioning of a shared services organization
- *Ongoing Efficiency is Expected*: Shared services performance should be measured for ongoing internal improvements in efficiency and effectiveness as well as overall improvements compared to the rest of the market place
- *Both Parties Share in Accountability*: Shared services performance measures should reflect shared accountability between the shared services organization and the different business units

The Shpigler Group originally examined the 2005-2006 Service Level Agreement established in 2005 against the above list of key SLA components and has determined that the SLA contains all the aspects of a sound service level agreement. Upon examination of the 2009-2010 Service Level Agreement we determined it to be similar to the 2005-2006 SLA, and 2007-2008 SLA with the exception of the expanded scope for carrier management services. However, a line by line audit of Schedule A of the SLA uncovered several sections that do not match the agreed upon work descriptions.

When the original SLA was written, it appears that the parties involved understood the applicability and frequency of certain activities. However, when new personnel not privy to the original negotiations and agreements read these same passages, they are open to interpretation. To preserve a successful ongoing relationship, we recommend that verbiage should be tightened to clearly reflect the exact requirements as well as identify any activities that are not covered under the SLA. We focused our examination on the metrics and reporting that is prescribed in the agreement and found that HOT continues to provide the services and reports as agreed and will continue to be held accountable to those same standards.

Service Level Agreement – There are defined services related to the monitoring, management, and operation of the Power System:

- Alarm Based Services
- Coordinated Network Management Services
- Systems Analysis Services
- Carrier/Vendor Management Services

Monthly Billing – All charges for network management and business services are electronically charged to the HONI accounting systems as pre-determined by both parties and reviewed annually.

Detailed Performance Reports – The following is a list of examples of the reports that are provided as defined in the SLA:

- Vendor Invoicing Error Report and Service Billing Report– Monthly
- Bill Savings Report - Annual
- PSTS Significant Events – Daily & Annual
- Year to Date Costs – Monthly
- Business Telecom Significant Events Report – Daily and Annual

All reports were reviewed and found to be in compliance with prescribed metrics. Verbal arrangements regarding the frequency of some of these reports have been made. For instance, the significant events reports are generated on a request-only basis.

Markup for Third Party Costs – A thorough review of all third-party billing was conducted to ascertain that costs billed to HONI were without markup. Billings from the largest vendor ($1,000,000 per month) to the smallest vendors ($100 per month) were reviewed, including the data inputted into the HONI accounting system, and all charges were without markup. The Shpigler Group again reviewed invoices and determined that all charges are being passed to HONI without markup.

Key Performance Metrics are Established – At the time of the last review, the performance metrics associated with contract handling and billing were centered on eliminating late payment fees and meeting new service dates. HOT solved the late payment issues by establishing a credit card payment system for billing for large vendors with next month corrections, and they have significantly reduced late payment fees. HOT has also established a monthly meeting with large suppliers for resolution and correction of billing issues, meeting reports are issued, and followed to resolution. On the network services side, restoration metrics were incorporated for loss of critical services (4 hours) and loss of redundancy (next day resolution). Also, performance measures were established for other trouble calls and corrective maintenance activities.

Priority 2, 3, and 4 levels with corresponding services response of 8 hours, 5 working days, and 10 working days were established. A review was made indicating that HOT is performing these services as defined.

Ongoing Efficiency is Expected – Efficiency expectations are established through fixed annual contract cost discussion and agreement between both parties. Since the inception of the contract an efficiency gain of 28.5% has occurred.

Both Parties Share in Accountability – Through annual discussion and adjustment memorandums, any change in scope of services is mutually agreed upon. However, there have been additional adjustments that while agreed upon, have not been noted in the formal SLA.

Cost Analysis

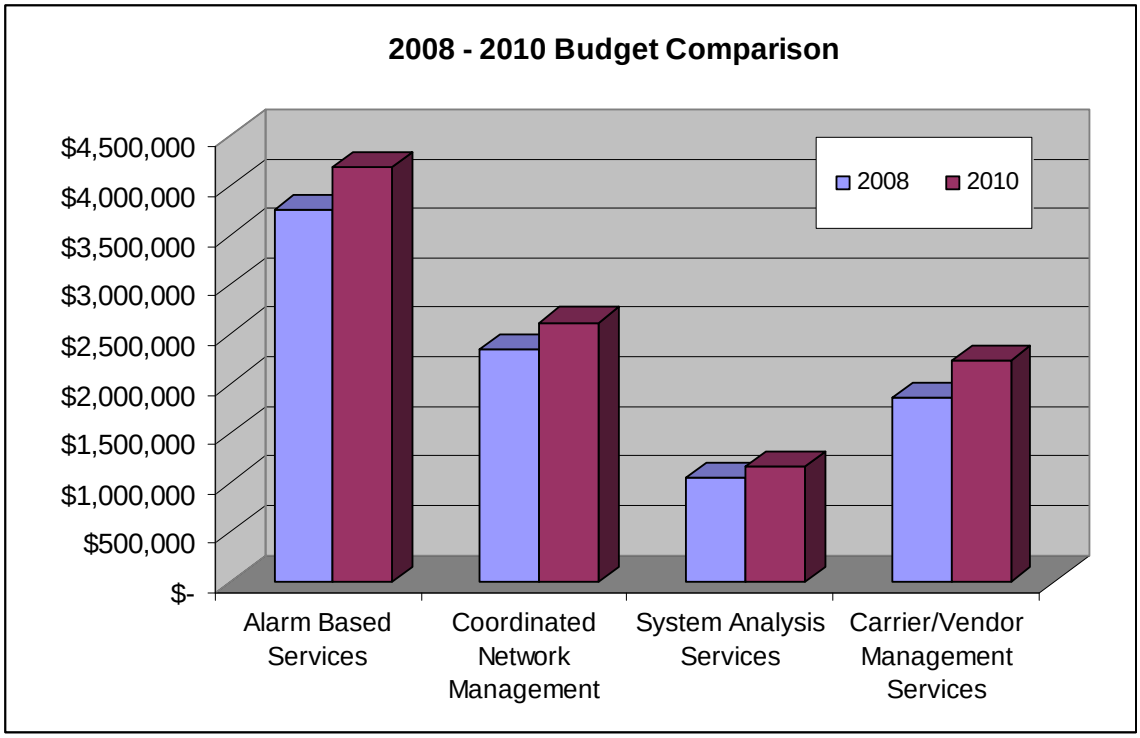
Our analysis on cost centered on the key components of costs and trends in costs.

HOT Vendor Management – The work performed by HOT is related to carrier and vendor management services. Since all bills and services are charged directly to HONI, HOT manages contracts, new orders, change orders, and bill analysis and payments. While there have been significant cost containment measures brought about by HOT contract negotiations, thorough bill analysis, and vendor interactions, the function remains labor intensive and is not conducive to ongoing efficiency increases or headcount reductions. Historically telecom billing engines have been error-laden. All major telecommunication service users perform detailed billing analysis to avoid over payment. We see this as a best practice and recommend continued close monitoring of service provider billings. Any efficiency gain is through the reduction in contract costs charged directly to HONI. Since 2002 HOT has identified $6.2 million in billing errors and has diligently sought correction to those errors. Over $2.5 million were annualized savings that would have continued to occur each year had they not been identified.

The vendor management services performed by HOT produces value for both organizations by increasing buying power. This is achieved by leveraging HOT's extensive commercial experience and thorough understanding of the market place

Based on a Utilities Telecommunications Council (UTC) report on shared services within utility telecommunications, entities indicate shared services costs are typically 40% labor, 40% vendor management and 20% infrastructure. The budget breakdown for HOT's management of HONI's telecommunications has a labor related component of 78% and a vendor management portion of 22%. Infrastructure related expenditures are not a part of this budget, but the higher labor to vendor ratio indicates that HOT continues to be in line with industry practices and is cost effectively managing vendors.

Budget Review

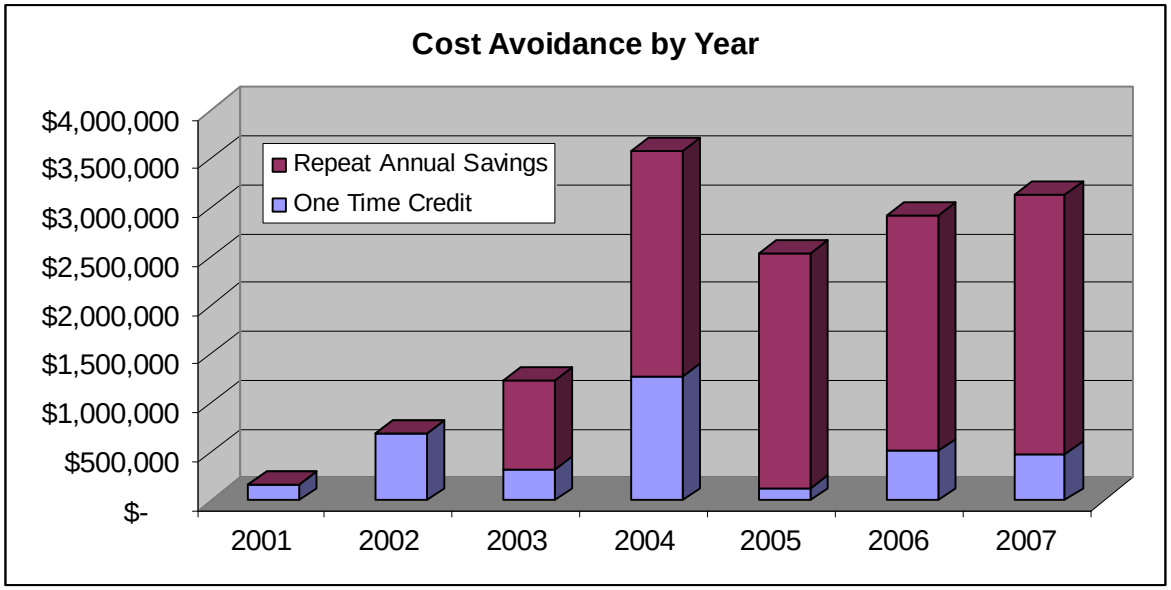


A comparison of budgets for 2008 and 2010 indicates slightly larger increases in alarm based services, coordinated network management and vendor management services, which is proportional to the increase in network elements. As per the 2009-2010 SLA agreement the only additional costs in this budget are associated with pre–defined workload increases and labor wage increases. The SLA contains a 5.7% per year wage increase for both 2009 and 2010.

HOT Cost Efficiencies – The cost effectiveness of the shared services offered by HOT is seen through the analysis of contract costs since the inception and the actual cost incurred by HOT. The expenditures for HOT operations are 100% labor as material; contract costs, equipment maintenance and upgrades are charged directly to HONI. HOT utilizes labor under the collective bargaining agreements of HONI and are bound by those contract terms, wages, and benefits. The contract to HONI did not increase from 2002 through 2006 even though wage increases were required by labor contract, indicating that HOT had to increase efficiencies to offset those increases which were approximately 5.7% per year. Had the telecom functions remained in HONI and not experienced the

shared service with HOT, HONI would be paying 28.5% more than it is now paying HOT. The budgets for 2009 and 2010 have increased over 2008 budget due to an increase in new incremental work (14.34%) and a labor wage increase (5.7%). There were no increases to the charges for service other than the mandated increases. Workload has continued to increase since the last review. During the last review, the total SLA charges were among the lowest of the reporting utilities. Even with the additional charges in the 2009-10 SLA, the overall SLA is still within an acceptable range of market standards as compared to the comparator group.

Third Party Billing Analysis **-** A thorough review of third party invoices and bills indicates that HOT has been performing well in controlling contracted costs and capturing billing errors. The following graph indicates the SLA cost for contract managements are far outweighed by the cost avoidance through billing corrections identified by HOT. It is a best practice for purchasers of extensive telecommunication services to have staff monitor bills and usage patterns to manage costs and internal usage. There is also an advantage to knowing call patterns and volume in extracting value for future service changes and contracted services. One can also expect to see the trend in savings reduce over time as vendor relationship and scrutiny tends to reduce errors. Since 2002, HOT's diligence has saved HONI $14.2 million dollars in both billing corrections and annual contract savings.



Conclusion

The shared services concept for telecommunications operations between HONI and HOT initiated in 2002 is providing the benefits that were perceived at its inception with the network monitoring cost for HONI being contained while providing for the unique services of a power system network and meeting the demands of a customer oriented commercial telecommunications network. The vendor management function is also providing the envisioned savings of a larger telecommunications entity.

- The decision to house a 24 x 7 network operations center dedicated to telecommunications operations has resulted in cost savings with some utilities, while others have seen troubling results. In situations where the monitoring center for the power system operations can be well trained on alarm dispatch procedures for telecommunications, the handoff to this group can be a viable approach to saving on operating demands. By contrast, where the electric monitoring center staff is not well trained, the results can be disastrous, as dispatch procedures are not followed and actual costs and overall impacts to the viability of the network can be challenging. The HOT operations have developed operator expertise in both the power systems and commercial telecommunications areas. The cost advantage that HONI is realizing is in shared network monitoring with commercial system expansions.
- A factor that we see as a large driver of determining the appropriateness of a 24x7 network operations center deals with the size of the utility and its telecommunications needs. For a smaller utility like Manitoba Hydro, outsourcing many of the network operations center activities during off-hours is not yet seen as a large work burden for the electric NOC personnel. However, implementing such a practice at a larger utility like Hydro One would prove to be very cumbersome and not provide the level of service required for both a power system and commercial telecom operation.
- The differentiating factor for the HONI operations as compared to the benchmarked utilities is that they have found a way to interject a commercial

telecommunication approach with a solid power system telecommunication operation to bring a successful and cost effective solution to both businesses.

- Benchmarking analysis to justify the specific expenditure for network monitoring services is difficult due to the wage and benefit structure among utilities; however our approach to base cost effectiveness on headcount and workload indicates that HOT is as good, if not better, than the other three Canadian utilities with network monitoring centers.
- The Service Level Agreement between HONI and HOT contains all of the necessary elements to define the scope of work, deliverables, reports and metrics to insure a successful partnership including shared accountability. However, the report needs to be updated to reflect the adjustments in scope that were verbally agreed upon during the normal course of operations in the last few years.
- Cost of services increases to HONI since 2002 have been less than if the network monitoring function had remained within HONI. HOT was at the bottom of the market when compared to the peer group of utilities in the 2005 review and even with labor and pension uplift in 2007-2008 SLA, HOT retained its position as one of the most cost competitive providers among the comparator group. The moderate increases in this most recent review of the 2009-2010 agreement still fall within acceptable norms of the industry.
- Vendor management services provided by HOT are enjoying advantages in both buying power and reduced unit costs for third party services.
- Bill monitoring and contract negotiations continue to result in considerable cost avoidance.

The Shpigler Group has extensive experience in utility telecommunications activities throughout North America and has investigated a number of integrations of commercial and utility network operations and vendor management. We believe that the benefits of a commercial telecommunication approach coupled with the power system knowledge is an effective tool in extracting value for both HONI and HOT in their respective areas of responsibilities. The key to any partnership is communication and pursuing common objectives. The HOT/HONI Service Level Agreement and its interactions, when

corrected to reflect verbal adjustments, will provide the direction and expectation for continued successful operations.

Ontario Energy Board (Board Staff) INTERROGATORY #50 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

50. Ref: ExhC1/Tab2/Sch 9/p17
Field Services costs grow by over 60% from 2008 to 2010. The evidence references a contract with Bell Canada which is to expire and be renewed for another 2 years. Please provide a detailed explanation of the need for additional services from Bell Canada considering the significant cost increases. Has Hydro One explored other lower cost options? If not, why not?

Response

The actual Field Services cost for 2008 of $2.8M was lower than planned due to the achievement of a planned cost reduction as stipulated in the contract with Bell Canada. This initiative included the realization of service credits, telecom asset cleanup and service discounts.

- The increase in cost of over 60% from 2008 to 2010 was primarily due to the completion of the contractual cost reduction initiatives in 2008 and head count increases, staff movements (move/add/changes to voice and data telecom configuration) as well as introduction of new sites requiring data and voice telecom.

A public request for proposal (RFP) was initiated in 2009 to evaluate and choose the lowest cost option available in the market-place for these services going forward into 2010 and beyond.

Ontario Energy Board (Board Staff) INTERROGATORY #51 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

51. Ref: ExhC1/Tab2/Sch 9/p20
IT Management costs appear to explode from $4.4 million in 2008 by 172% to $12 million in 2009 and another 51% to $18.1 million in 2010. Please provide additional clarity to the reasons given for the expansion of this program. Please include a detailed list of additional activities or projects, the cost of each project, why the project is necessary, and the benefits of each project.

Response

Of the $13.7M increase in cost from 2008 to 2010, $12.4M is due to internal re-organizational transfers. IT financial and supply chain support (+0.6M) as well as the Enablement department (+6.6M) were transferred from Finance at the beginning of 2009 and the Information Assets department will be transferred from Asset Management effective 2010 (+$5.2M).

The remaining increase of $1.3M is due to the addition of personnel for business application support of SAP, Program management, IT Outsourcing management, Business Intelligence/Business Warehouse (BI/BW) support and governance and Smart Grid information systems support and governance.

Ontario Energy Board (Board Staff) INTERROGATORY #52 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

Ref: ExhC1/Tab2/Sch 10/p1

How do the additional costs for Cornerstone as referenced in Schedule 9 under IT Sustainment relate to the savings presented on this table?

Response

The Cornerstone OM&A expenditures shown in Exhibit C1, Tab 2, Schedule 10, page 1 Table 1 are the OM&A costs associated with the development/execution of the capital project. Table 1 shows the enterprise wide OM&A savings directly associated with the completion of the capital project.

The costs referenced in Exhibit C1, Tab 2, Schedule 9, under IT Sustainment, relate to OM&A expenditures required to sustain Cornerstone after the project phases are commissioned in-service. Cornerstone Phase 1 and Phase 2 attract sustainment OM&A expenses as they move from capital project status to in-service status in 2009 and 2010 respectively.

Ontario Energy Board (Board Staff) INTERROGATORY #53 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services – IT

Ref: ExhC1/Tab2/Sch 11/p1

Please provide a detailed explanation to how the estimate for Contestable Work, Lines and Distributed generation was determined at the level of $36.2 million in 2010. What assumptions were made to arrive at this estimate?

Response

An update of ExhC1/Tab2/Sch 11 was filed with the OEB on September 25, 2009. Costs associated with Lines – Contestable work are expected to be $5.2M in 2010 and $5.3M in 2011.

As part of the evidence update (filed September 25, 2009), the costs associated with Distribution Generation ($36.2M-$5.2M=$31M) has been moved to become part of the Generation Connections Costs (for more details, please go to Exhibit D1, Tab 3, Schedule 3, section 2.2). This change is in accordance with the proposed amendments to the DSC issued by the Board on September 11, 2009.

Ontario Energy Board (Board Staff) INTERROGATORY #54 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

54. Ref: ExhC1/Tab2/Sch 5/p1

The evidence in the Customer Care schedules often references significant increases in costs due to the increase in activity for distributed generation and smart grid. Please provide more specific rationale, cost drivers and justification for the need for these increased resources in real terms, ie, number of distributed generation projects to be place on line, etc.

Response

A summary of the costs and an explanation of changes in Customer Care Work Program expenditures over the planning period are provided on pages 3-4 of Exhibit C1, Tab 2, Schedule 5. Total Customer Care costs are decreasing in the test years relative to 2009 forecast spending. Cost have increased relative to 2008 actuals due primarily to three factors: changes to scope or implementation timing of projects; an increase in bad debt and third-party contracts related to collection activities; and additional expenditures related to servicing new renewable distributed generation customers.

Under the Ontario government's Green Energy and Green Economy Act, fixed price contracts with a 20 year term will be provided by the Ontario Power Authority to increase the number of renewable generators in the province. Many of these generators are expected to be connected to Hydro One's distribution system. This new segment of customers will require customer services of contact handling, settlements and generation payments.

Customer Care began work early in 2009 to prepare for the questions and phone calls from renewable generator customers as government announcements were underway, and, to prepare systems and processes to connect and respond to customers by program launch.

The increased costs related to new renewable generation customers, and included in the Customer Care Work Program, cover the cost of:

- call handling capability at the Customer Communications Centres
- manual meter reading requirements until new generator customers are aligned into Hydro One's schedule for automated reading
- resources to establish dedicated contacts for generator customers, to manage a smooth connection process, to develop and manage the various contracts throughout the connection process and provide ongoing communication.
- updates to the Customer Relationship Management tool necessary for management of contact and relationship with distributed generation customers
- resources to pay these renewable generators for power produced, to settle metering data given these customers will have one or more complex bi-directional meters and, to settle with the IESO for the difference between payments made under generator contract prices and electricity commodity price.

In Customer Care's planning assumptions, it was assumed there would be 130 FIT contracts annually, and 3,600 microFIT contracts annually. In addition, it was assumed multiple contacts would be received from customers interested in the FIT program.

There are no costs for Smart Grid included in the Customer Care Work program.

Ontario Energy Board (Board Staff) INTERROGATORY #55 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

55. Ref: ExhC1/Tab2/Sch 5/p3
Please provide in table format, total Customer Care costs per customer for each year from 2004 to 2011. Please calculate the year-to-year variances and identify the drivers for the increase/decrease.

Response

The table below provides the Customer Care cost per customer and year to year variance

Description	2004	2005	2006	2007	2008	2009*	2010*	2011*
Total Customer Care cost (M$)	103.0	96.3	103.7	97.1	99.3	106.7	106.3	102.4
Customers (K)	1,145	1,158	1,170	1,183	1,193	1,203	1,213	1,223
Customer Care cost per Customer ($)	89.96	83.16	88.63	82.08	83.24	88.69	87.63	83.73
Year to year variance		(7.6%)	6.6%	(7.4%)	1.4%	6.5%	(1.2%)	(4.5%)

* Forecast of cost and number of customers at year-end

The cost of the Customer Care work program can vary between years due to a number of variable factors such as; bad debt costs; incremental costs to address volume changes in calls to the Customer Communications Centre, usually due to high storm years; or, the cost of projects to implement regulatory changes coming into effect in a particular year.

Costs to the end of 2007 were reviewed as part of Hydro One Distribution's 2008 Cost of Service application (EB-2007-0681). Costs were down in 2005 as a result of an extended labour disruption. In 2006 costs were higher due to an allowance provision of $3.6 million related to a multiyear adjustment to bad debt costs, as well as due to higher communication centre costs incurred as a result of the high number of storms experienced that year.

Expenditures increase in 2009 primarily due to three factors, as noted in Exhibit C1, Tab 2, Schedule 5, page 3: changes to scope or implementation timing for Regulatory or

Service enhancement projects, for example, the delay to 2009 of the Hydro One 2008 distribution rate changes; an increase in bad debt and third-party contracts costs related to collection activities due to forecasted impact of economic conditions; and, additional work associated with serving new renewable distributed generation customers.

The decrease in 2011 reflects the cost decline in the meter reading budget with the migration of customers to automated meter readings.

Ontario Energy Board (Board Staff) INTERROGATORY #56 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

Ref: ExhC1/Tab2/Sch 5/p3

What proportion of Customer Care and other Services was/is accounted for by the Inergi contract from 2006 to 2011? Please provide a general description the Inergi contract, time frame, costs and a list of all services provided through Inergi. If significant shifts in costs between Inergi and Hydro One are evident from year to year, please provide the rationale for such cost shifts.

Response

The Inergi contract accounts for the proportion of total Customer Care work program costs shown in the Table below. There has been no significant shift in costs between Customer Care and Inergi.

	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Total Customer Care Costs	103.7	97.1	99.3	106.7	106.3	102.4
Customer Service Operations	39.0	39.3	39.5	39.7	42.8	42.0
Inergi Proportion	38%	40%	40%	37%	40%	41%

Under the Inergi contract, services are provided to Customer Care, Supply Management Services, Finance and Accounting, Information Technology, HR Payroll and Settlements. The timeframe for the Inergi contract is March 2002 until February 2012. A general description of the Inergi contract, including time frame, costs and a list of all services provided by Inergi, was included in Hydro One Distribution's 2008 Rates Application (EB-2007-0681) as part of Exhibit C1, Tab 2, Schedule 6, Attachment A.

A description of the services provided by Inergi specifically to Customer Care is included in the current Application at Exhibit C1, Tab 2, Schedule 5, section 2.1.1.

Ontario Energy Board (Board Staff) INTERROGATORY #57 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

Ref: ExhC1/Tab2/Sch 5/p5

Please provide a table detailing the cost reductions in base service fees in the Inergi contract, from 2004 to 2011 (forecast). How have these cost reductions compared to the forecast cost reductions cited in previous rates cases before the OEB (EB-2007-0681 and EB-2005-0378)?

Response

The Customer Care services of billing, settlements, contact handling and collections are delivered through the contract with Inergi. A base service fee reduction for these services is defined within the Inergi contract, a copy of which was provided in response to interrogatory Exhibit H, Tab 13, Schedule 14 filed as part of Hydro One Distribution's 2008 Rate Application (EB-2007-0681). The contracted service fee reductions have not changed from when the contract was originally negotiated (i.e. no change from cost reductions included in EB-2005-0378 and EB-2007-0681) and Hydro One confirms that these cost reductions have been realized each year of the contract.

Ontario Energy Board (Board Staff) INTERROGATORY #58 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

58. Ref: ExhC1/Tab2/Sch 5/p5

Hydro One indicates that it is moving to monthly billing for those 140,000 customers on bi-monthly billing. What are the reasons for Hydro One's move to monthly billing and not moving more to bi-monthly billing? What are the additional costs incurred when moving to monthly billing?

Response

Hydro One is planning to change billing frequency from bi-monthly to monthly, for approximately 140,000 acquired customers, starting in 2010. This change will align billing frequencies for the majority of Hydro One customers; establish more consistent processes; provide customers with more frequent consumption and pricing information when time-of-use rates are introduced; and, eliminate service differences once rate harmonization is completed and both acquired and legacy customers are consolidated to the residential and general service rate classes.

Hydro One did not consider moving approximately 1 million customers from monthly to bi-monthly billing. Customer research has indicated that there would be an adverse reaction to changing our customers' billing frequency from monthly to bi-monthly due to concern over the size of the bill and difficultly in paying the resulting higher amounts. Key benefits with monthly billing are seen as the ability to budget monthly and the more manageable bill amounts.

Additional costs will be incurred by Hydro One when this change is made, estimated at $580,000 annually. This estimate is based on an additional 840,000 bills issued per year. This incremental cost is included with the Smart Meter Project costs used in the determination of the Smart Meter funding adder discussed at Exhibit F1, Tab 1, Schedule 3.

Ontario Energy Board (Board Staff) INTERROGATORY #59 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

Ref: ExhC1/Tab2/Sch 5/p8

Hydro One indicates that by 2011, all of its 1.2 million meters will be read on an automated basis but that some meters will still be read manually. How many meters will remain on manual reading? Why does Hydro One's meter reading cost not fall further than the budgeted level of $5.3 million in 2011?

Response

Please see Exhibit C1, Tab 2, Schedule 5, page 8, section 2.1.2, for a description of the migration of customers to automated meter reading.

Customers will be migrated throughout 2010 and 2011. The change to automated reading will take place gradually, with some customers moving each month throughout the year. By the end of 2011 it is expected 1.2 million meters will be automated.

The 2011 meter reading budget of $5.3 million is required for both manual meter reading and interval meter reading. The 2011 plan includes a requirement for an estimated 632,000 manual meter reads up until the transition takes place. Further, there continues to be a requirement for manual meter reading for a variety of situations, including:

- remote locations where smart meter communication is not available
- to check a meter reading at a customer's request
- for meter investigations
- initial meter reading after new customer connections

Ontario Energy Board (Board Staff) INTERROGATORY #60 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

Ref: ExhC1/Tab2/Sch 5/p10

Under Other Service Support costs, Hydro One shows an 18% increase in the bridge year with this level spending continuing in 2010 and a further 7% increase in the 2011 year. What are the major drivers of these cost increases? Why would costs go up for ePost billing when the presumption is that electronic billing would reduce costs?

Response

The factors contributing to the increase in 2009 bridge year costs are described in Exhibit C1, Tab 2, Schedule 5, section 2.1.4. As noted in the pre-filed evidence we are expecting a higher level of activity in collections related contracts. The budget also reflects fees to offer eBilling services. Another contributor to cost increases in 2009 is an expected increase in the Canada Post postage rate by $0.01, and a small increase in customer volume.

Hydro One agrees that electronic billing will reduce costs. This was factored into the test years and helps to offset increases in Canada Post postage fees and customer volume.

The factors contributing to the increase in 2011 costs are described in Exhibit C1, Tab 2, Schedule 5, section 2.1.4. As noted in the pre-filed evidence we are planning the addition of a service provider to assist Hydro One telephone access during significant events such as storms. The plan also reflects a Canada Post postage rate increase of $0.01.

Ontario Energy Board (Board Staff) INTERROGATORY #61 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Ref: ExhC1/Tab2/Sch 5/p12
Under Service Enhancements, Hydro One shows a 113% increase in 2009 to $3.4 million in 2010 and a reduction in these costs in 2011. Why did Hydro One not consider reducing or eliminating service enhancements in 2009 and 2010 in recognition of the cost pressures faced by customers in those years?

Response

Service enhancements planned for 2010 and 2011 are detailed in section 2.4 of Exhibit C1, Tab 2, Schedule 5, page 12 through 13. These service enhancements are required to align with Hydro One's corporate objectives of 90% customer satisfaction; drive productivity improvements; and meet customer ongoing expectations voiced through customer research.

The increased cost of service enhancements in 2009 is not borne by customers as Hydro One Distribution's current rates reflect only the $2.6 million in service enhancement costs approved by the Board in the Company's last cost of service application (EB-2007-0681).

Ontario Energy Board (Board Staff) INTERROGATORY #62 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

Ref: ExhC1/Tab4/Sch 1/p17

Supply Chain Management: Table 4 on this page shows an increase of 22% in supply chain costs from 2008 to 2010. Please provide a more detailed explanation for this increase over the two years and also indicate how the Inergi contract influenced this cost escalation. Please also relate this increase to the description of productivity improvements found on page?

Response

The 22% increase in Supply Chain Management costs in 2010 over 2008 is primarily due to increased activities related to the overall growth in the capital and OM&A work programs across the organization. The primary drivers behind the increases are:

- Increases in transport and warehousing costs;
- Cost increases driven by additional volumes being handled by Inergi; and,
- Cost increases for implementing the demand planning and strategic sourcing initiatives to ensure the availability of critical resources (materials and equipment), as well as the platform to monitor the realization of strategic sourcing cost savings that are described in Exhibit C1, Tab 4, Schedule 1 p21 & 22. These initiatives are used to obtain the productivity improvements found in Exhibit C1, Tab 4, Schedule 1 p22.

Ontario Energy Board (Board Staff) INTERROGATORY #63 List 1

Interrogatory

Issue 3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Shared Services - Customer Care

Ref: ExhC1/Tab5/Sch 1/p3

Tables 1 and 2 present the allocation of CCF&S costs as allocated in 2010 and 2011. Please provide a similar table for 2008 as approved by the Board in the EB-2007-0681 rate decision and also for 2008 actual.

Response

The table below presents the 2008 Actual and Board approved allocation of CCFS costs (in $ millions):

2008 Actual

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	6.1	3.2	2.8	0.1	0.0	0.0	0.0
Finance	32.2	16.4	14.7	0.6	0.2	0.3	0.1
Human Resources	13.6	7.1	6.2	0.1	0.0	0.1	0.0
Corporate Communications	6.1	3.3	2.8	0.0	0.0	0.0	0.0
General Counsel & Secretariat	6.4	3.0	2.9	0.1	0.1	0.2	0.1
Regulatory Affairs	17.2	9.2	7.9	0.0	0.0	0.0	0.0
Corporate Security	2.1	1.1	1.0	0.0	0.0	0.0	0.0
Internal Audit	2.5	1.2	1.1	0.0	0.1	0.1	0.0
Total CCFS Costs	**86.1**	**44.5**	**39.5**	**0.9**	**0.4**	**0.7**	**0.1**

2008 Board Approved

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	6.2	3.2	2.8	0.1	0.1	0.0	0.0
Finance	26.9	13.6	12.1	0.6	0.2	0.3	0.1
Human Resources	12.6	6.0	6.4	0.1	0.0	0.1	0.0
Corporate Communications	5.7	1.9	3.8	0.0	0.0	0.0	0.0
General Counsel & Secretariat	7.5	4.1	2.9	0.1	0.1	0.2	0.1
Regulatory Affairs	19.7	9.4	10.3	0.0	0.0	0.0	0.0
Corporate Security	2.5	1.3	1.2	0.0	0.0	0.0	0.0
Internal Audit	3.0	1.9	0.9	0.0	0.1	0.1	0.0
Total CCFS Costs	**84.2**	**41.3**	**40.5**	**0.9**	**0.5**	**0.7**	**0.2**

Ontario Energy Board (Board Staff) INTERROGATORY #64 List 1

Interrogatory

Issue 3.4 Are the methodologies used to allocate Shared Services and Other O&M costs to the distribution business and determine the distribution overhead capitalization rate for 2010/2011 appropriate?

Ref: ExhA/Tab13/Sch 1/p4, lines 21 to 26

a) Hydro One is requesting a rate treatment for PP&E, intangible assets and depreciation consistent with current CGAAP for purposes of IFRS in 2011. Please indicate what the accounting treatment would be and the dollar impact on costs and revenue requirement in each of 2010 and 2011 if the Board chooses not to accept this proposal.

b) The July 28, 2009 Board report "Transition to International Financial Reporting Standards (Appendix 2, article 3.3) states:

"The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first cost of service rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified."

i) Please file a copy of Hydro One Distribution's capitalization policy, and identify any changes from current policy that are being proposed to apply beginning in 2010 and any further changes beginning in 2011.

ii) Indicate which components of the costs are affected by each change identified in a) above, and the impact on the costs that would be capitalized, if Hydro One Distribution were not depending on the Board's rate setting authority to authorize the pattern of inclusion of these costs in rates.

Response

a) Hydro One expects that its IFRS capitalization practices will be the same as those that currently exist under Canadian GAAP. This is based on an assumption that the International Accounting Standards Board's recent exposure draft on accounting for Rate Regulated Activities results in a final accounting standard that is essentially unchanged from the proposal. Given the exposure draft's proposed treatment for costing of rate regulated PP&E, Hydro One would not expect any costing differential for PP&E on either a Canadian GAAP or IFRS basis.

To date, Hydro One has done extensive work to identify specific accounting differences between Canadian GAAP and IFRS. This will prepare the ground for potential future work required to quantify these differences in the event that the exposure draft does not result in an accounting standard that allows for the continuance of the existing costing framework for PP&E. However, at this time it is not possible to quantify the impact of these differences.

Hydro One's independent depreciation consultant, Foster Associates Inc., is in the initial stages of determining appropriate straight-line deprecation rates to be applied under an IFRS environment.

b)

i) Hydro One Distribution does not have its own specific "capitalization policy." Distribution capitalization accounting practices are governed by several Hydro One corporate policies including:

- Allowance For Funds Used During Construction (AFUDC) and Interest Capitalization (Attachment 1 – SP 0774 R0)
- Classification of Expenditures (Attachment 2 – SP 0775 R0)
- Cancelled Capital Projects and Capital Projects with Rescheduled In-Service Dates (Attachment 3 –SP 0776 R0)
- Cost Allocation and Transfer Pricing (Attachment 4 – SP 0804 R0)

Revisions to reflect the requirements of IFRS will be contingent on the outcome of the IASB's rate regulated activities project. Revisions to existing policies and procedures to reflect the requirements of IFRS are expected to be completed in the first half of 2010.

ii) In the absence of costing PP&E under the provisions of the rate regulated accounting exposure draft, assets would be costed in accordance with other IFRS such as IAS 16 "Property, Plant and Equipment." Hydro One has not computed the impact on cost capitalization under this scenario given the expectation that a final regulatory accounting standard in some form is expected to supersede standard IFRS costing requirements and lead to asset recognition of those costs that are otherwise disallowable for capitalization under IFRS.

Document Number: **SP 0774 R0**

Document Name: **Allowance For Funds Used During Construction (AFUDC) and Interest Capitalization Policy**

Issue Date: **September 2008**

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The requirements of this document are mandatory.

Purpose

This policy describes the requirements with respect to allowance for funds used during construction and interest capitalization for both regulated and non-regulated business.

Revision

Information contained in the policy, approved in June 2000, is now contained in this document.

Contents

1.0 Policy Statement

2.0 Scope

3.0 Corporate Requirements

3.1 Regulated Businesses

3.2 Non-Regulated Businesses

4.0 Definitions

4.1 Carrying Costs

4.2 AFUDC

Appendix A: Document Management

1.0 Policy Statement

To comply with generally accepted accounting principles and regulatory requirements, the cost of a major fixed asset that is acquired, constructed or developed over time shall include carrying costs attributable to the acquisition, construction or development activity.

2.0 Scope

This policy applies to all construction in process amounts in the regulated and unregulated businesses unless a specific exemption has been provided by Corporate Finance.

3.0 Corporate Requirements

3.1 Regulated Businesses

3.1.1

The carrying cost to be capitalized is the amount resulting from the application of the OEB's approved "Allowance for Funds Used during Construction" (AFUDC) rate to major fixed asset expenditures included as construction in progress. This rate may include a deemed cost of equity financing.

3.1.2

The AFUDC rate will either be a specific rate provided by the OEB or will be a rate calculated by the Company based on OEB guidance or parameters and approved by the OEB.

3.1.3

Capitalization of AFUDC will cease once the asset is declared in-service (Exceptions - see policy for "Cancelled Capital Projects and Capital Projects with Rescheduled In-Service Dates").

3.2 Non-Regulated Businesses

3.2.1

The carrying cost to be capitalized is the actual incremental borrowing cost attributable to major fixed asset expenditures included as construction in progress. Generally accepted

accounting principles do not allow for the capitalization of the deemed cost of equity capital for an unregulated enterprise.

3.2.2

When specific debt is issued to finance a particular capital project, the carrying cost to be capitalized shall be the actual effective interest cost related of the specific debt.

3.2.3

When pooled debt is used to finance a capital project, the carrying cost to be capitalized is actual average effective cost of all debt outstanding.

3.2.4

Capitalization of carrying costs shall cease once the asset is in-service (Exceptions - see policy for "Cancelled Capital Projects and Capital Projects with Rescheduled In-Service Dates.")

4.0 Definitions

4.1 Carrying Costs

In the context of this policy, carrying cost is the financing cost over time that is directly or indirectly attributable to expenditures made on a capital project and included in construction in progress.

4.2 AFUDC

The Allowance for Funds Used During Construction (AFUDC) amount results from a rate that generally reflects the cost of borrowed capital and which may also include a cost attributable to equity financing. The AFUDC rate is either set by the OEB or is subject to OEB approval.

Appendix A: Document Management

Owner/Functional Responsibility	Corporate Finance
Approval Date	June 2000
Approval Required By	Executive Committee, Chief Financial Officer
Effective Date	June 2000
Document Last Reviewed	August 2008

Document Number: **SP 0775 R0**

Document Name: **Classification of Expenditures**

Issue Date: **August 2009**

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The requirements of this document are mandatory.

Purpose

This document specifies the requirements relating to classification of expenditures incurred between capital and OM&A.

Revision

Information contained in the policy with the same name on the Finance website, approved in July 2004, is now contained in this document. The changes made from the current review to the existing document are considered to be not material.

Contents

1.0 Scope

2.0 Policy Statement

3.0 Corporate Requirements

4.0 Definitions

Appendix A: Materiality Limits for Capital Additions

Appendix B: Document Management

1.0 Scope

This policy applies to each of the businesses and subsidiaries of Hydro One Inc., whether regulated or unregulated.

2.0 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 records those expenditures that have future economic benefit as assets. Accordingly, expenditures that are material in amount and which meet the definition of an asset shall be capitalized.

3.0 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 of new or replacement components for existing assets; and
    d. betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific existing assets.

Current materiality limits are provided in Appendix A.

Exception - Materiality limits shall not apply to asset component replacement transactions. In such transactions, determination of classification as capital or OM&A is made with reference to plant retirement unit definitions.

- Expenditures qualifying for capitalization include direct labour, direct materials and supplies, transportation costs, directly attributable external costs, fees, and permits.
- Indirect expenditures qualifying for capitalization include (1) financing costs (i.e. interest costs for unregulated subsidiaries and the regulator's allowance for funds used during construction for regulated subsidiaries, (2) attributable shared functions and services costs (e.g. general engineering, administrative salaries and expenses, insurance and taxes), and (3) attributable indirect depreciation of equipment, tools and transport and work equipment used in the capital project.
- Decommissioning, fixed asset removal and site restoration costs shall be charged to current operations (i.e. depreciation expense) as incurred unless a related asset

retirement obligation (ARO) has previously been recorded in the financial statements. If an ARO has been recorded, related expenditures are to be charged to the related balance sheet provision.

- Materials, supplies and capital spares purchased for future use are generally not immediately capitalized as in-service assets, nor are they immediately charged to operations. Materials, supplies and most spare capital components are either recorded as inventories or future use fixed assets. Materiality limits and business facts will determine the final accounting classification of inventory items as capital or OM&A.

Specific Requirements:

Assets Not Owned by Hydro One

Expenditures made by Hydro One on assets not ultimately owned by Hydro One, but that meet the definition of an asset through the continued provision of future economic benefits, shall be capitalized provided there is assurance that the asset's future economic benefits will continue to be accrue to Hydro One (i.e. asset can be included in rate base).

Carrying Charges

Carrying charges shall be capitalized as asset acquisition costs as long as a project is undergoing active design and construction activity and there is a reasonable expectation of completion and future recovery. Attributable carrying charges shall be charged to current operations once a project is either declared in-service or 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 proportion of the cost of common facilities in a multiple-asset facility (e.g. a Transformer Station) shall be placed in-service in proportionate to the total output or benefit represented by the assets being declared in-service.

Computer Software Costs

System software expenditures and major applications software project expenditures with an expected future useful life equal to or exceeding two years shall be capitalized as intangible assets. All other software expenditures shall be charged to current operations as incurred. Computer software expenditures may not be capitalized as minor fixed assets.

Software acquisition and enhancement costs shall include:

- Software purchase costs (including internal and external customization expenditures);
- Attributable development costs where software is internally developed;
- Data purchase and data loading costs;
- System testing and commissioning, and
- System documentation.

Expenditures for clean up of existing data prior to data loading are not capitalized as they represent repair costs.

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 acquisition cost of the software asset.

Major software projects that consist of several related but independent modules should be placed in service as each module meets the criteria (see definition of 'in service") to be placed in service.

Contributions in Aid of Construction

Fixed assets funded in whole or in part by external parties are capitalized at gross cost to Hydro One. Any contributions received from external parties should be recorded in capital accounts as a specific asset contra account (i.e. credit account) offsetting the gross asset cost.

Contributions made by the Hydro One to other related or unrelated regulated businesses may be capitalized if they meet the definition of an asset. Such cases should be referred to Corporate Finance given the high degree of accounting judgment to be applied in determining whether or not asset recognition criteria are met.

Land and Land Rights

Capitalized land costs include direct purchase costs, including appraisal costs, fees, commissions, surveys, title search and registration, and clearance costs of unwanted buildings (net of recoveries). Costs for first clearing and land preparation costs specifically related to construction and installation of facilities 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 also include Hydro One's cost of acquiring finite or indefinite termed rights, interests, easements and privileges in land owned by others.

Leases

Leases shall be designated as capital or operating in accordance with the lease accounting requirements 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 (e.g. deferral and amortization) should be sought. All other repair expenditures shall be expensed as incurred.

Major Reserve Equipment

The cost of major reserve 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. The cost of major reserve 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 work site.

The cost of major equipment acquired for installation under a future construction project shall be treated as future use assets, similar to other significant plant components.

Mobile Distribution Station Equipment

The service costs, including depreciation, rental, connection and disconnection, and moving such mobile distribution equipment, shall be charged to a 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 service costs of mobile equipment used for other purposes shall be charged to current operations.

Penalty Payments

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

Plant Retirement Units (PRU's)

Replacements of asset components that qualify as PRUs shall be treated as capital transactions. The replacement component is capitalized and the replaced component is retired. Any fixed asset removal costs are charged to depreciation expense on an as incurred basis.

Expenditures to replace a component part of a PRU, or for the removal or relocation of a PRU, shall be charged to current operations as incurred.

Premium Labour Costs

Premium labour costs incurred in performing work during an emergency, no matter whether the base work is of a capital or current expense nature shall be charged to operations as incurred.

Project Development Costs

Project development, estimating and pre-engineering costs shall be capitalized from the date that a "preferred alternative" has been selected and approved. All general and specific project costs incurred prior to the selection 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 on accounting for intangible assets in the CICA Handbook.

Temporary Facilities Built to Assist Construction

The net cost of building and removing such facilities, including labour and materials 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 the estimated service life is equal to or grater than two years.

Training Costs

Direct training costs related to facilities 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 all training costs associated with capitalized computer software projects, shall be charged to current operations as incurred. All proposed treatments leading to the potential capitalization of training costs should be referred to Corporate Finance for concurrence.

4.0 Definitions

Many definitions relevant to this policy are provided in the Canadian Institute of Chartered Accountants' Handbook, in section 1000 (Financial Statement Concepts), section 3061 (Property, Plant & Equipment), section 3065 (Leases) and section 3064 (Goodwill and Intangible Assets).

Addition: An expenditure made to physically add to an existing capital asset. A "betterment" is also an addition.

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 is set or 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 beyond its original specification. This can be accomplished by an increase in service life, increase in output, reduction in operating costs etc. A repair or refurbishment is not a betterment. A betterment does not exist unless the original expectations of service potential are exceeded.

Capital Asset: Fixed assets 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. Often, the term is used to refer to financing costs only.

Commissioning (or Testing): The need for commissioning or testing work can occur 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, 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 "property, plant & equipment."

Future economic benefits: Future economic benefits are generally evidenced by an increase in net cash inflows. 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 do not result in the capitalization of

interest (or AFUDC for regulated assets), nor are they depreciated or amortized. Major capital spare parts and certain lands make up the majority of this asset class.

In-service Asset: An asset is declared in-service when it is substantially complete and ready for commercial use. In a regulatory context, the asset must also meet the test of being "used and useful" to have its service costs included in revenue requirement. 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.

Intangible asset: An asset is an identifiable non-monetary asset without physical substance. Examples include most types of computer applications software.

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 should be requested from the regulator.

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 the criteria to be considered capital assets, are capitalized. All other expenditures are charged to current operations as incurred. Dollar materiality limits are not used in classifying asset component replacements as capital or OM&A (see PRUs)

Penalty Payment: Any additional payment made to suppliers as a result of canceling or changing the terms of a contract or failing to meet the terms of an agreement, 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 Units (PRUs): The smallest unit of capital asset that will result in a capital replacement transaction being recorded in the accounts. When an asset component that is a PRU is replaced, the old PRU is retired and the new one is capitalized. Component replacements that are not PRUs are expensed and no retirement transaction is recorded.

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 of sufficient authority provides approval for a specific capital project. The exact point where a preferred alternative exists depends on business circumstances and may differ for demand capital, program capital or project capital, as well as for software projects.

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. Costs incurred prior to the preferred alternative are expensed and those incurred following the preferred alternative are capitalized.

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 it 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 and when in-service declaration is deferred by management. Capitalization of interest continues when the asset becomes ready for service and when in-service declaration is delayed by external factors. 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 its former good operating condition.

Replacement: The act of replacing one capital asset, asset component 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

Appendix B: Document Management

Owner/Functional Responsibility	Corporate Finance - Director, Corporate Accounting and Reporting
Approval Date	October 2000
Approval Required By	Corporate Finance - Corporate Controller
Effective Date	October 2000
Document Last Reviewed	August 2009

Document Number: **SP 0776 R0**

Document Name: **Cancelled Capital Projects and Capital Projects with Rescheduled In-Service Dates**

Issue Date: **August 2008**

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The requirements of this document are mandatory.

Purpose

This policy describes the requirements with respect to capitalization of acquisition and carrying costs of capital projects.

Revision

Information contained in the policy, approved in October 2000, is now contained in this document.

Contents

1.0 Policy Statement

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3.0 General Requirements

4.0 Definitions

4.1 Construction, Acquisition or Development Costs

4.2 Cancelled Capital Projects

4.3 Capital Facilities with Rescheduled In-Service Dates

4.4 Carrying Charges

Appendix A: Document Management

1.0 Policy Statement

Acquisition costs related to capital projects, including carrying costs, are capitalized as part of the cost of the capital project as long as a project is undergoing active design and construction activities and there continues to be a reasonable expectation of completion.

2.0 Scope

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

3.0 General Requirements

3.1

Carrying charges shall be capitalized on a qualifying capital project as long as it is undergoing active construction, acquisition or development activity and there continues to be a reasonable expectation of completion.

3.2

Carrying charges shall be charged to current operations during the period when substantially all construction, acquisition or development activities related to a project are suspended (i.e. "tools are put down").

EXCEPTIONS

- Carrying charges shall continue to be capitalized when the suspension of work is due to external factors beyond the control of corporate management, provided that a reasonable expectation of completion remains;
- In cases where the OEB orders a specific regulatory treatment for carrying charges, Corporate Finance will be asked to review or determine the appropriate accounting treatment to be used to conform with generally accepted accounting principles.

3.3

The capitalization period shall end when substantially all construction, acquisition or development are completed and the project is considered ready for use, unless declaration of in-service has been delayed by external factors outside management's control. In such cases, capitalization of carrying charges shall continue until the externally imposed delay has been resolved.

3.4

When the construction, acquisition or development activities related to a project are suspended and there is no longer a reasonable expectation of completion, all project costs shall be written off to current period results of operations (i.e. OM&A).

EXCEPTION

- Capitalized project costs with residual value to other existing or probable future capital projects may be transferred to those project accounts if those costs are related to the project, qualify as assets under generally accepted accounting principles, and are expected to be recoverable in rates. Prior to any such transfer, advice and approval should be sought from Corporate Finance.

4.0 Definitions

4.1 Construction, Acquisition or Development Costs

Costs that relate to the purchase or design and construction of an asset and that are necessarily incurred to bring that asset to the condition and location of its intended use.

4.2 Cancelled Capital Projects

Capital projects are considered to be cancelled when all related design and construction activities are suspended and there is no longer a reasonable expectation of completion.

4.3 Capital Facilities with Rescheduled In-Service Dates

Capital projects with rescheduled in-service dates are those having their in-service dates postponed into the future. Four possible separate scenarios are described as follows:

Delayed Capital Projects

Capital projects are delayed when construction, acquisition or development activities are suspended due to factors beyond the corporation's control (such as material shortages, vendor strikes, local labour disruption, weather, or vendor scheduling or design problems. In general, with a delayed capital project, it is the intent of the Corporation to continue design and construction activities at a later date.

Deferred Capital Projects

Capital projects are considered to be deferred when the Corporation decides to halt all construction, acquisition or development activities as a result of such factors as a change in expected near term future need, government requirements, and availability of alternative courses of action, changes in technology or internal schedule changes. In

general, with a deferred capital project, it is the intent of the corporation to interrupt design and construction activities for a finite period of time.

Extended Capital Projects

Capital projects are extended when the corporation decides to postpone the scheduled in-service date into the future and construction, acquisition or development activities continue uninterrupted at a reduced pace.

Ready-for-Use Capital Projects

Capital projects are considered to be ready for use when design and construction activities are complete and virtually all tests required to place the project in commercial operation are substantially complete but the use of the facility is postponed for a period. If the postponement is due to an internal decision, capitalization of carrying charges ceases. If the decision is outside management's control and due to external factors, capitalization of carrying charges is continued.

4.4 Carrying Charges

Carrying charges are recurring costs associated with the possession or ownership of property. They include interest for an unregulated asset and the regulator's allowance for funds used during construction (AFUDC) for a regulated asset.

Appendix A: Document Management

Owner/Functional Responsibility	Corporate Finance
Approval Date	October 2000
Approval Required By	Executive Committee, Chief Financial Officer
Effective Date	October 2008
Document Last Reviewed	August 2008

Document Number: **SP 0804 R0**

Document Name: **Shared Corporate Services Cost Allocation and Transfer Pricing Policy**

Issue Date: **September 2009**

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The requirements of this document are mandatory.

Purpose

This document specifies accounting policies for the allocation of shared services and transfer pricing for the transactions between Hydro One Inc.'s subsidiaries, regulated businesses and their affiliates.

Revision

Information contained in the policy with the same name on the Finance website, reviewed in November 2004, is now reviewed, updated and contained in this document.

Contents

1.0 Scope

2.0 Policy Statement

3.0 Corporate Requirements

4.0 Definitions

Appendix A: Document Management

1.0 Scope

This policy applies to the sharing of corporate services and all transfers (i.e. transactions involving the providing or receiving) of services, products, resources, or use of asset, between Hydro One's utilities and their affiliates

2.0 Policy Statement

The allocation of costs relating to shared corporate services shall occur in a manner that ensures that Hydro One's utilities do not cross-subsidize their affiliates.

3.0 Corporate Requirements

The cost allocation methodology shall conform to the following general requirements:

1. Where costs can reasonably be identified with a specific unit of product or service or with a specific operation or cost centre, such costs should be assigned on a direct cost basis. Application of this principle should take into consideration the materiality of such direct cost assignments relative to the cost of implementing such assignments, recognizing any constraints with existing information systems and/or business processes.

Exceptions – Shared corporate functions and services costs are not generally charged directly to work projects and programs. Any proposal to charge such costs directly requires explicit review and approval by the Corporate Controller.

2. Any residual shared corporate services costs ("shared costs") remaining after direct costs are assigned or charged should be allocated to the receiving utility or affiliate using a rate that is based on a "fully-allocated cost" model.

3. The cost driver/allocator selected to derive the allocation rate shall be selected based primarily on the principle of "cost causality". If a strong causal relationship cannot be established, the principle of "benefit" shall be used.

4. If the most appropriate theoretical cost driver/allocator cannot be used due to system constraints or the absence of required information, the most appropriate proxy that meets the causality/benefit principle shall be selected.

5. The overall cost allocation methodology shall be periodically reviewed for continued appropriateness and drivers and rates shall be updated on an annual basis. All changes in direct and indirect costs, the allocation methodology, or cost drivers/allocators shall be appropriately documented.

Affiliate transactions involving utilities shall conform to the following requirements found in the OEB's Affiliate Relationships Code:

1. The term of an Affiliate Contract between a utility and an affiliate shall not exceed five years, unless otherwise approved by the OEB.

2. If a utility intends to enter into an Affiliate Contract for the receipt of a service, product, resource, or use of asset that it currently provides to itself, the utility shall first undertake a business case analysis, unless the Affiliate Contract would have an annual value of less than $100,000 or 0.1% of the utility's utility revenue, whichever is greater. Where an Affiliate Contract has a term of more than one year, the annual value of the Affiliate Contract shall be determined by dividing the total value of the Affiliate Contract by the number of years in the term.

   The business case analysis shall contain (a) description of relevant utility needs on a per-service basis, (b) identification of the options available internally or externally from an affiliate or third party, (c) economic evaluation of all available options including the utility's current fully-allocated cost (which may include a return on the utility's invested capital equal to the approved weighted average cost of capital), (d) explanation of the selection criteria (including any non-price factors to be taken into account), (e) estimate of any benefits to the utility's Ontario ratepayers from outsourcing, and (f) justification of why any separate items were bundled together when considered for outsourcing.

3. "Shared corporate services" *means business functions that provide shared strategic management and policy support to the corporate group of which the utility is a member, relating to legal, regulatory, procurement services, building or real estate support services, information management services, information technology services, corporate administration, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee, or public affairs.*

4. For shared corporate services, fully-allocated cost-based pricing (as calculated in accordance with sections 7 and 8 below) may be applied in lieu of applying the transfer pricing provisions described in sections 5 and 6 below, provided that the utility complies with section 9 below.

5. Where a market exists, a utility shall pay no more than the market price when *acquiring* that service, product, resource or use of asset from an affiliate.

6. Where a market exists, a utility shall, when *selling* a service, product, resource or use of asset to an affiliate, charge an affiliate no less than the greater of (i) the market price of the service, product, resource or use of asset and (ii) the utility's fully allocated cost to provide the service, product, resource or use of asset.

7. Where no market exists, a utility *buying* a service, product, resource or use of an asset shall pay no more than the affiliate's fully-allocated cost to provide that

service, product, resource or use of asset. The fully-allocated cost *may* include a return on the affiliate's invested capital. The return shall be no higher than the utility's approved weighted average cost of capital.

8. Where no market exists, a utility *selling* a service, product, resource or use of an asset to an affiliate shall charge no less than its fully-allocated cost to provide it. The fully-allocated cost *shall* include a return on the utility's invested capital. The return shall be no less than the utility's approved weighted average cost of capital.

9. Where a utility pays a cost-based price for a service, product, resource or use of asset that is obtained from an affiliate, the utility shall obtain from the affiliate, from time to time as required to keep the information current, a detailed breakdown of the affiliate's fully-allocated cost of providing the service, resource, product or use of asset.

4.0 Definitions

Affiliate: Has the same meaning as in the Ontario *Business Corporations Act*.

Benefit: When a causal relationship cannot be established, a cost driver/allocator is selected that measures the proportionate degree of benefit provided by the shared product/service to the recipient unit(s).

Causality: The existence of a causal relationship between a particular cost and a triggering unit, product or service is determined by analyzing whether the cost would have occurred had the triggering item not existed.

Cost Driver/Allocator: Method or ratio used to apportion indirect costs. It can be a measurable event or quantity identified with a specific unit of product or service, a cause and effect relationship between the indirect cost and the causing/benefiting activity, or one or more factors referred to as general allocators.

Direct cost: A cost that can reasonably be directly associated with a specific unit of product or service, or with a specific operation or cost centre. For direct costing to occur, a relevant direct charge mechanism must exist.

Fully allocated costs: The sum of all direct costs plus a proportional share of indirect costs

Indirect cost:A cost that cannot be identified with a specific unit of product or service, or with a specific operation or cost centre. Can also be a direct cost when no direct cost mechanism exists.

Utility: a licensed electricity transmitter or distributor (as defined by the Affiliate Relationships Code).

Appendix A: Document Management

Owner/Functional Responsibility	Corporate Finance – Director, Corporate Accounting and Reporting
Approval Date	November 2004
Approval Required By	Corporate Finance - Corporate Controller
Effective Date	November 2004
Document Last Reviewed	September 2009

Ontario Energy Board (Board Staff) INTERROGATORY #65 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: ExhA-14-1/Appendix A/p4

The table shows payroll burden from 2008 to 2014. Please provide similar figures for 2006 and 2007. The table also indicates that for both Regular and Non-Regular staff the payroll burden increases from 5.66% in 2008 to 6.2% in 2010. What is the impact of this change in dollars and what is the primary driver of this increase over the two years?

Response

Company	Category	2006[1]	2007[2]
Networks	Non-Regular Staff % of total earnings*	 6.2%	 6.3%
	Regular Staff % of total earnings* % of base pensionable earnings**	 6.2% 44.71%	 6.3% 41.3%
	Pension % of base pensionable earnings	 27.89%	 29.1%

The impact of the payroll burden increases from 5.66% in 2008 to 6.2% in 2010 is $4M. This increase is due to changes in staff count and mix.

[1] Reference: EB-2006-0501, Exhibit A, Tab 14, Schedule 1, Appendix A
[2] Reference: EB-2006-0501, Exhibit A, Tab 14, Schedule 1, Appendix A

Ontario Energy Board (Board Staff) INTERROGATORY #66 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

66. Ref: ExhA-14-1/Appendix A/p2

The evidence indicates a 3% economic increase effective April 1, 2009 and 2010 for Society represented staff. However 589 of 1029 Society represented staff will have annual progressions, as will 15% of PWU staff. How are these annual progressions factored into the Labour Escalation?

Response

Annual wage progressions are factored into the calculation of composite wage rates. The economic increase is then applied to the composite wage rates in order to determine overall labour escalation.

Ontario Energy Board (Board Staff) INTERROGATORY #67 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

67. Ref: ExhC1/Tab 4/Sch1/p2

Table 1 provides an example of how the Labour Rate is built up for a Regional Line Maintainer. The rate shows a decrease from $111 in 2008 to $110 in 2010. How does this example reconcile with evidence in Appendix A that shows an escalation of 3% each year?

Response

Exhibit C1, Tab 4, Schedule 1 Table 1, includes five elements of cost that are used to determine the labour rate for a Regional Line Maintainer. There is a 3% escalation that is applied to the employee's base wage rate. There are also reductions in other elements of the burdened rate such as reductions in the pension based on actuarial assumptions, as well as reductions in other post employment benefit (OPEB) rates that have contributed to the lowering of the overall labour rate for the Regional Line Maintainer.

Ontario Energy Board (Board Staff) INTERROGATORY #68 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

68. Ref: ExhC1/Tab3/Sch1/p1

Hydro One indicates that 1000 networks staff will be eligible for an undiscounted retirement by December 31, 2009 which grows to 1,400 by December 31, 2011. In Hydro One's experience, what proportion of those eligible will actually take advantage of this option? Has Hydro One considered or designed any programs to encourage eligible staff to choose to continue employment rather than retire? If so, what are these programs?

Response

Over the period 2005-2008, on average, about 10% of eligible staff who could retire actually retired annually. It should be noted that historical trends do not necessarily accurately predict future retirement uptake.

Retention programs aimed at encouraging senior staff to continue working have limited short term benefits. As such, there are no wide scale structured programs designed or anticipated to encourage eligible staff to choose to continue employment. However, Hydro One has used retention agreements on an exception basis only to retain senior staff who possess unique and specialized skills. Any retention agreements require the retained employee to transfer knowledge to another employee.

Hydro One believes that a more sustainable and longer term strategy to deal with large scale retirements is to invest in programs where knowledge transfer is the key objective. Programs such as the New Grad and apprentice hiring, Fellowships and knowledge documentation all contribute to ensuring knowledge is transferred to more junior staff.

Ontario Energy Board (Board Staff) INTERROGATORY #69 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

69. Ref: ExhC1/Tab3/Sch1/p1

When Hydro One replaces a long tenured employee who retires early and replaces that employee with a new hire, what is the average impact on wages? How much does Hydro One save in salary by hiring a younger less experienced worker?

Response

There are many variables involved with new hires that makes it very difficult to be estimate the impact on wages or savings as a result of hiring younger and less experienced workers. Factors such as training, timing of the hire, productivity and the employee classification all have to be considered.

Hydro One has made significant progress in reducing costs for new employees hired for Society and Management positions. Less costly benefit and pension programs have been introduced for new MCP employees hired after January 1, 2004 and pensions for new Society employees hired after November 2005. Lower entry level wage rates have also been negotiated for new Society employees.

Ontario Energy Board (Board Staff) INTERROGATORY #70 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

70. Ref: ExhC1/Tab3/Sch1/p8

Regarding the PWU Hiring Hall, how are Hydro One's costs reduced when using PWU hiring hall workers? Where are the savings in using a hiring hall worker rather than a full time PWU employee?

Response

The PWU hiring hall enables Hydro One to supplement the regular workforce with mobile and flexible workers to perform seasonal and supplemental trades work.

PWU hiring hall workers do not participate in the Hydro One pension or benefits program. In addition, hiring hall employees are more easily ''stood off' when the work program dictates so expensive termination costs are avoided. While on 'stand off', Hydro One has no financial obligation to these employees. Hiring hall employees can be recalled which is a benefit to Hydro One since these workers have been previously trained to Hydro One standards.

As an example of the cost saving attributed to using the PWU hiring hall, a Hiring Hall Lines journeyperson is approximately 33% less expensive than the regular PWU Lines journeyperson.

Ontario Energy Board (Board Staff) INTERROGATORY #71 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

71. Ref: ExhC1/Tab3/Sch2/p9

Please provide the annual number of employees that correspond to these payroll levels by year. Please also include the 2008 level corresponding to the Board approved rates for 2008. Can this table be meaningfully presented by separating the payroll costs and employee numbers into transmission and distribution? If so, please provide this information, if not, why not?

Response

Year End Headcount Hydro One Networks Inc. (TX and DX)*

Classification	**2008**	**2009**	**2010**	**2011**
Regular	4714	5,185	5848	6053
Temporary	1833	2271	3704	4192
Total	**6547**	**7456**	**9552**	**10 245**

* This table reflects year end headcount for all EPSCA, PWU, Society and MCP staff

The payroll costs and employee numbers cannot be separated between Transmission and Distribution. Hydro One Networks has an integrated workforce for its Transmission and Distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations.

Ontario Energy Board (Board Staff) INTERROGATORY #72 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

72. Ref: ExhC1/Tab3/Sch2/p9

As shown in Table 3, overtime costs have increased from $67.8 million in 2006 to a projected $87.6 million in 2010. Why have overtime costs increased to such an extent over this two year period?

Response

The question posed references a 4 year period but asks for an explanation for a 2 year period. The answer to this question will assume a 4 year period.

Overtime costs are higher from 2006-2010 due to an increasing work program and labour escalation. Overtime is driven by the essential nature of Hydro One's business. Factors that result in overtime include storm restoration, trouble calls, system outages off peak time, geography and major line construction projects.

Ontario Energy Board (Board Staff) INTERROGATORY #73 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: ExhC1/Tab3/Sch2/p9

On this page, Hydro One indicates that the total Networks work program is expected to increase by over 35% whereas the regular staff increase is expected to increase by only 16%. How does Hydro One plan address this gap and with what resources? In filing this gap with other resources, how much does Hydro One estimate it will save compared to using regular employees?

Response

As discussed in Exhibit A, Tab 16, Schedule 1, page 8, Hydro One will continue to utilize a variety of resources such as contractors, temporary and hiring hall staff in addition to regular staff to complete the increasing work program. Emphasis on 'turn key projects' will also be an important strategy to complete the work program.

By using resources other than regular staff, Hydro One will have labour flexibility and save in the areas of pension and benefit costs, recruitment and employment termination costs.

Ontario Energy Board (Board Staff) INTERROGATORY #74 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: ExhC1/Tab3/Sch2/p10

At lines 8 and 9, Hydro One indicates that its compensation levels and structures have fallen below the market for top people. Please explain this assertion further: What is meant by the term "top people" and what evidence can Hydro One provide to back up this statement?

Response

"Top people" are prospective MCP employees who are highly skilled, engaged, flexible, productive and motivated.

MCP compensation, defined as base salary and benefits/pension, has been a barrier to successfully recruiting external applicants, in particular, to MCP field supervisory and engineering positions. An ideal candidate for these positions will typically have a minimum of 15 years of experience in the industry. Feedback from applicants as to why they decided not to join Hydro One was that our compensation and benefits were not competitive against competing offers. Furthermore, the Mercer/Wyman Compensation Cost Benchmarking Study conducted in 2008 illustrates that Hydro One's MCP total compensation is slightly below median against Hydro One's peer group.

Ontario Energy Board (Board Staff) INTERROGATORY #75 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: ExhC1-3-2/Appendix A/p2

The table shows annual pension cost for both the transmission and distribution businesses for 2010 and 2011. Please expand the table to show similar costs from 2006 to 2009 and include the 2008 level corresponding to the Board approved rates for 2008.

Response

Annual cash pension cost (millions)
(*may not add due to rounding*)

2006

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	$ 4	$ -	$ 6

2007

Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$ 24	$ 35	$ 3	$ 62
Capital	$ 14	$ 24	$ -	$ 38
	$ 38	$ 59	$ 3	$ 100
Inergi Annual Pension Charge				
OM&A	$ 2	$ 4	$ -	$ 6

2008

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

2009

Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$ 28	$ 34	$ 2	$ 64
Capital	$ 17	$ 26	$ -	$ 43
	$ 45	$ 60	$ 2	$ 107

Inergi Annual Pension Charge				
OM&A	$ 1	$ 4	$ -	$ 5

2010

Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$ 28	$ 35	$ 3	$ 66
Capital	$ 17	$ 27	$ -	$ 44
	$ 45	$ 62	$ 3	$ 110

Inergi Annual Pension Charge				
OM&A	$ 1	$ 4	$ -	$ 5

2011

Corporate Pension Costs	Transmission	Distribution	Other	Total
OM&A	$ 29	$ 37	$ 3	$ 69
Capital	$ 18	$ 28	$ -	$ 46
	$ 47	$ 64	$ 3	$ 114

Inergi Annual Pension Charge				
OM&A	$ 1	$ 4	$ -	$ 5

1

Ontario Energy Board (Board Staff) INTERROGATORY #76 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: ExhA/Tab13/Sch 1/p 6-7 – Employee Future Benefits
Hydro One has requested "a rate treatment for pension consistent with current CGAAP for the purposes of IFRS in 2011". It is not clear from the submission exactly what is requested. Please clarify the request and explain why Hydro One considers it necessary for the Board to grant such request(s). Please indicate what the accounting treatment would be and what the dollar impact on costs and the revenue requirement would be in each of 2010 and 2011 if the Board chooses not to accept this proposal.

Response

Hydro One Distribution is requesting that pension costs be based on a cash (funding) basis, consistent with CGAAP and past applications. The use of a cash basis allows for smoothing- of cost inputs over time, thus minimizing variations on the revenue requirement and therefore customer impacts. In anticipation of the International Accounting Standards Board's exposure draft on rate regulated accounting, no adjustment to this basis was considered necessary in 2011 when IFRS is applicable.

If the Board chose not to accept this proposal, pension costs would need to be computed under an accrual basis on CGAAP for 2010 and IFRS for 2011. The accrual basis would require estimates of return on assets, discount rates and other economic assumptions. Given the basis of rate setting for pension costs under CGAAP and IFRS was considered compatible, the dollar impact of a change to accrual was not computed under either CGAAP or IFRS.

Ontario Energy Board (Board Staff) INTERROGATORY #77 List 1

Interrogatory

Issue 3.8 Is the amount proposed for income taxes, including the methodology, appropriate?

Ref: ExhA/Tab13/Sch1/p5-6 – Payment in Lieu of Corporate Taxes
Hydro One Distribution has requested a rate treatment consistent with current CGAAP for the purposes of IFRS in 2011. It is not clear from the submission exactly what it is that Hydro One Distribution is requesting. Please clarify what is being requested and explain why Hydro One Distribution considers it necessary for the Board to grant such request(s). Please indicate what the accounting treatment would be and what the dollar impact on costs and the revenue requirement would be in each of 2010 and 2011 if the Board chooses not to accept this proposal.

Response

Hydro One Distribution is requesting that the expense for payments in lieu (PILs) be based on a cash (flow through) basis, consistent with CGAAP and past applications. In anticipation of the International Accounting Standards Board's (IASB's) exposure draft on rate regulated accounting, no adjustment to this basis was considered necessary in 2011 when IFRS is applicable.

If the Board chose not to accept this proposal, PILs would need to be computed under an accrual basis on CGAAP for 2010 and IFRS for 2011. The accrual basis would require estimates of future income tax asset and liabilities. Given the basis of rate setting for PILs under CGAAP and IFRS was considered compatible, the dollar impact of a change to accrual was not computed under either CGAAP or IFRS pending the finalization of the IASB's rate regulated activities exposure draft.

Ontario Energy Board (Board Staff) INTERROGATORY #78 List 1

Interrogatory

Issue 3.9 Is the proposed spending on loss reduction efforts appropriate?

Ref: ExhG1/Tab 10/Sch1/p1
Hydro One indicates that losses are estimated to be higher than the values currently approved by the Board.

a) Why are the values higher? Why have Hydro One losses increased since 2008?

b) On the same page, Hydro One indicates that it is making ongoing efforts to reduce losses. What are these ongoing efforts? What amount of O&M dollars are being spent on line loss improvements? Please provide a list of programs and initiatives and their approximate costs.

Response

a) The statement does not claim that losses have increased since 2008. The statement refers to losses estimates provided in the losses study conducted by Kinectrics and filed in Proceeding EB-2007-0681 as Exhibit A, Tab 15, Schedule 3, Attachment A. The analysis contained in the study showed that estimated losses were higher than the OEB approved losses. As was the case in its last Application, Hydro One continues to propose maintaining the OEB approved distribution loss factors.

b) Hydro One reviews its system configuration routinely to ensure effective and efficient operation. Each feeder in its system is computer modeled on a regular basis and wherever conditions such as voltage are found to be outside guidelines, remedial measures are taken. The first such measure considered is always the addition of capacitors, which offer line loss improvements as a primary benefit. Phase line current balance is also brought within target guidelines as a result of this work and losses are reduced in this way as well.

Customer power quality concerns are identified from time to time. If the customer issue is regarding low voltage, then a capacitor will be considered for installation if it can affect a solution. Recommendations for effective solution of issues require study and computer modeling.

The costs of technical staff performing these studies are included in O&M expenditures. It is impossible to separate out the amount spent on loss reduction alone; however Hydro One estimates approximately $1.4 M is spent annually to perform these studies.

Ontario Energy Board (Board Staff) INTERROGATORY #79 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: S7

In the noted Reference, the Table covering the period from 2006 to 2011 showing poles replaced is reproduced below for clarity:

	2006	2007	2008	2009 Plan	2010	2011
Poles Replaced (units)	1,393	1,321	827	1,350	1,150	1,150

a) Please explain the reasons for the large drop of about 37 % in the number of poles replaced in 2008 (827 poles) from the corresponding number in 2007(1,321 poles).

b) Please provide the reasons for the large increase of about 63 % in the number of poles to be replaced in 2009 (1,350 poles) from the corresponding number in 2008 (827 poles).

c) Please provide historical "Capital and MFA" investment amounts for the years "2006 to 2008" and for the "2009 Plan" shown in the bottom Table of the noted Reference, broken into the two categories "Poles Replaced" and "Equipment Replaced".

Response

a) As noted at the bottom of page 16 of Exhibit D1, Tab 3, Schedule 2, reductions in emergency pole replacements are attributed to Hydro One Distribution's focus on pole replacement and inspection activities over recent years. The magnitude of the reduction in 2008 was beyond expectations, and is not expected to be repeated in the short term. Hydro One Distribution will continue to monitor the situation but expects that the red pine pole issue will place upwards pressure on accomplishments over the medium term.

b) The 2009 plan for pole replacement units was estimated using data from 2004 to 2007. The drop in emergency pole replacements in 2008 is reflected in the plan for 2010 and 2011, but was not included in the 2009 plan as the 2009 projection was completed in the early part of 2008.

c) Funding for poles replaced and equipment replaced is not tracked in two separate categories. The table below provides historical "Capital and MFA" investment amounts for emergency pole and equipment replacement for the years "2006 to 2008" and for the "2009 Plan".

	2006 ($M)	**2007 ($M)**	**2008 ($M)**	**2009 Budget ($M)**
Capital * and MFA (A)	$21.0	$21.0	$15.9	$22.4
Operating, Maintenance & Administration and Removals (B)	$2.5	$2.5	$1.9	$2.7
Gross Investment Cost (A+B)	**$23.5**	**$23.5**	**$17.8**	**$25.1**
Capital Contribution (C)	$0	$0	$0	$0
Net Capital (A+C)	**$21.0**	**$21.0**	**$15.9**	**$22.4**

Ontario Energy Board (Board Staff) INTERROGATORY #80 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: S8

a) Please provide the historical investments from 2006 to 2008 and for 2009 Plan by expanding the Table in the noted Reference, to better appreciate how the historical amounts relate to the forecasted ones.

b) Given the nature of the non-discretionary nature of these capital investments, please describe the basis of the forecast especially during the current economic downturn.

Response

a) The historical investments from 2006 to 2009 are provided in Table 3 of Exhibit D1, Tab 3, Schedule 2, page 14.

b) Hydro One Distribution's forecasts for 2010 and 2011 are based on a weighted 4-year average of historical expenditures. These forecasts align with macro-economic expectations as discussed in Exhibit A, Tab 14, Schedule 4, which predict that the economy will enter a period of growth in 2010 and 2011 following recessionary conditions in 2009. It should be noted that the impact of the recessionary conditions on the Joint Use and Line Relocations Program will also be tempered by government stimulus funds that are being directed to infrastructure projects. A portion of these stimulus funds are committed to road, highway, and bridge expansions or improvements, which in turn drive increasing demand expenditures by the Joint Use & Line Relocation Program.

Ontario Energy Board (Board Staff) INTERROGATORY #81 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: S10

a) Please provide the historical investments from 2006 to 2008, and the 2009 Plan by expanding the Table in the noted Reference, to better appreciate how the historical amounts relate to the forecasted ones.

b) To have a better understanding of that program, please also provide for the revised Table in Reference a) above, the number of poles replaced for the historical years (2006 to 2008), 2009 Plan as well as for the forecast for 2010 and 2011.

Response

a) The historical investments from 2006 to 2009 are provided in Table 4 of Exhibit D1, Tab 3, Schedule 2, page 20.

b) Please refer to the following table for the requested additions.

	2006 ($M)	**2007** ($M)	**2008** ($M)	**2009 Forecast** ($M)	**2010** ($M)	**2011** ($M)
Net Investment	**30.3**	**40.1**	**43.0**	**42.2**	**46.4**	**59.0**
Poles Replaced	5,193	6,852	6,736	7,000	7,500	9,500

Ontario Energy Board (Board Staff) INTERROGATORY #82 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

82. Ref: ExhD1/Tab3/Sch2/p14
Table 3 shows that capital spending in 2010 and 2011 due to trouble calls and storm damage is projected to be $59.3M and $59.2M.

a) Since damaged equipment due to storms consume a great deal of Hydro One resources, has Hydro One considered any novel ways to mitigate the damage due to these storms such as: 1) software to assist in weather analysis and to provide more rapid and accurate prediction for storm intensity, location and times; and 2) the early marshalling of repair crews at predicted storm locations so as to reduce repair duration at these locations?

b) Since storm damages consume a great deal of Hydro One resources, has Hydro One discussed this matter with other LDCs.?

c) If Hydro One has had discussions with other LDCs regarding storms, what has it learned from these other LDCs and if it as not carried out such investigations, why has it not?

Response

a)

1) In 2009, a new weather service application was fully implemented in the OGCC control room, providing weather detail overlaid with Dx and Tx assets. In addition, the Pelmorex weather service (The Weather Network) provides detailed weather forecast daily, special advisories and a meteorologist is available 7x24 if required. The current day to day strategy is for the OGCC to provide Significant Event Notification (SENS) via email of imminent weather conditions, issued weather watches and warnings with specific location information to all internal stakeholders.

2) Calls are made from the OGCC shift managers to Provincial Lines management informing them of current storm conditions, initial damage and customer impact and crew requirements. Based on this, extra crews are made available for storm response. Although advance crew deployment has been invoked on some

occasions we have found that, due to the nature of major storm activity in Ontario, it has been more effective to hold crews until the full extent and location of the storm damage is available. The Provincial Lines organization is very adept and well practiced at mobilizing resources of all types in a strategic manner to respond to system damage.

b) Yes.

c) Discussions with other LDC's have resulted in Mutual Assistance agreements. During major events LDCs play a considerable part in the Hydro One storm restorations.

Ontario Energy Board (Board Staff) INTERROGATORY #83 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

83. Ref: ExhD1/Tab3/Sch3/p2

Table 1 provides a summary of Hydro One development capital. The table and footnotes do not provide a clear picture of planned capital spending. (ie. In 2010 generators are funding $13.3 million in generation connection costs, and it is also noted external funding for generation connections is stated to be $43 million, and generation connection enhancements are all externally funded at $62.4 million. This does not add to the total of $105.4 million quoted for external funding in the final footnote.) Please provide a clear explanation of the total capital spending for 2010 and 2011 that is assumed to be covered with external funding and what capital funding is to be included in rate base.

Response

The issue raised in the interrogatory was addressed as part of the update to Exhibit D1, Tab 3, Schedule 3 that was filed with the Board on September 25, 2009. The information in Table 1 of Exhibit D1, Tab 3, Schedule 3 is consistent with the information provided in the updated Green Energy Plan provided at Exhibit A, Tab 14, Schedule 2.

The total Green Energy Plan related Capital spending assumed to be recovered from generators, external funding and included in rate base is summarized in the table on page 1 of the Green Energy Plan. The split of the capital costs specifically associated with renewable generation work is summarized in the table on page 24 of the Green Energy Plan. For additional clarity, a break out of the costs by Connection, Expansion and Renewable Enabling Improvement (REI) capital spending for 2010 and 2011 is provided below:

2010:	
Connection Costs - Generator	$13.3M
Expansion Costs – Hydro One	$12M
Expansion Costs – External	$60M
REI Costs – Hydro One	$4M
REI Costs – External	$79M
DG related 2010 External funding	$139M
DG related 2010 Hydro One funding	$17M
2011:	
Connection Costs - Generator	$27M
Expansion Costs – Hydro One	$25M
Expansion Costs – External	$118M
REI Costs – Hydro One	$8M
REI Costs – External	$118M
DG related 2011 External funding	$236M
DG related 2011 Hydro One funding	$33M

Ontario Energy Board (Board Staff) INTERROGATORY #84 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

84. Ref: ExhD1/Tab3/Sch3/p5

The evidence indicates that new connections for 2009 are forecast to be 15,000, increasing to 15,300 in 2010 and 2011. This is an increase of 2%. However, capital spending is set to increase from $77.4 million in 2009 to $84.6 million in 2010, an increase of over 9%. Please provide an explanation for the spending increase.

Response

The increase is due to cost escalation, the increasing number of new connections, replacement of existing plant resulting from increased adherence to Regulation 22/04 that cannot be recovered from new customers (e.g. installation of inter spaced poles on spans that exceed Hydro One approved standards, line reconfiguration required to accommodate new connection) and the reduction in capital contributions due to the proposed amendments to the DSC noted in Hydro One's updated submission of September 25th, 2009.

Ontario Energy Board (Board Staff) INTERROGATORY #85 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

85. Ref: ExhD1/Tab2/Sch1/p24 & 25 and ExhD2/Tab2/Sch2/p1
It is noted in that expenditures of $4.8M and $5.7M are projected for 2010 and 2011 for submarine cables. As Hydro One has indicated at Exhibit D1 Tab 2, Schedule 1, pages 24 and 25 in the pre-filed evidence that the failures in submarine cables tend to be close to shore, has Hydro One considered plowing the cable deeper into the lake or river bed near the shore line or protecting it with concrete "pavers" or some other overlay and if not, why not?

Response

Hydro One Distribution's current construction standard for submarine cable installations does include trenching and several types of mechanical protection for cables at the shoreline.

The trenching alternative is utilized wherever possible but such protection is impractical on many installations that are located on rocky shorelines. For these locations, alternative forms of mechanical protection are utilized including poured concrete and articulated piping.

Newer cable installations along with those that have been mechanically protected pose reduced risks but are still susceptible to corrosion. For example, when trenching is utilized, natural forces (e.g. water movement, erosion) within water bodies can expose buried cables. Furthermore, other types of mechanical protection can deteriorate over time and can contribute to cable deterioration.

Ontario Energy Board (Board Staff) INTERROGATORY #86 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

86. Ref: ExhD1/Tab3/Sch3/p7

The evidence shows System Capability Reinforcement capital costs growing by 28% from 2008 actual to 2010 and then a further 9% in 2011. Please provide the specific drivers that would warrant such an increase at this time.

Response

Recently completed technical studies have targeted areas of load growth which historically have some of the worst performing assets from a reliability and power quality standpoint. The studies have identified issues with system capacity, substandard system protections, low voltage, and lack of loop feed capability that exists in areas generally referred to as "cottage country" – i.e. Muskoka/Parry Sound, Georgian Bay Islands, etc. Increased year-round usage, conversion of seasonal residences to permanent, and upgrading of traditional cottages to large square-footage residences has resulted in increased stresses on the network and increased funding is required in order to address the supply and reliability needs in these areas. Examples of these projects are Rosseau DS & Muskoka TS M1 Line extension ($9.2M), Port Severn DS & Line Work ($4.1M), and Twelve Mile Bay DS & Line Work ($4.6M).

Ontario Energy Board (Board Staff) INTERROGATORY #87 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: D1

To better understand the weight of each the three components of the investment, it is important to not only obtain the contribution of each for the forecast years of 2010 and 2011, but to also obtain these details for the historical years 2006 to 2008 and for 2009 Plan. Please provide the details described in the Preamble by completing the Table below.

	$ Millions					
Year	**2006**	**2007**	**2008**	**2009 Plan**	**2010**	**2011**
Capital and Minor Fixed Assets					135.4	137.8
New Connections						
Service Upgrades						
Cancellations						

Response

Meter Purchases has been added to the table as it is included in the capital component of this program.

	$ Millions					
Year	**2006**	**2007**	**2008**	**2009 Plan**	**2010**	**2011**
Capital and Minor Fixed Assets	126.8	128.2	129.0	122.1	135.4	137.8
*New Connections	80.1	84.6	80.0	77.4	86.6	86.9
*Service Upgrades	21.4	19.7	20.7	19.1	21.4	21.6
*Meters Purchases	3.1	1.6	1.1	1.5	5.5	6.9
**Cancellations	0	0	0	0	0	0

* Excludes Capital Contributions
**Cancellations are not capitalized

Ontario Energy Board (Board Staff) INTERROGATORY #88 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

88. Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: D12

The evidence in states in part that:

> "Based on average load growth in the area of 1% per year, the stations approaching their design limits are expected to exceed those within the next 5 years. This will be compounded by a major commercial and residential development that is being planned near the village of Minett (i.e. Red Leaves Development) which is expected to add an additional 6 to 8 MVA of load in the next 10 years over and above the base load growth.
>
> In order to address the identified supply issues, an Area Supply Planning Study was carried out which examined various alternatives for meeting future supply needs. This study recommended a plan to build a new 44-12.8 kV Rosseau DS near the village of Rosseau. The new station will rely on a feed from the Muskoka TS M1 44 kV and will require a 14 km feeder extension. This investment will fund the recommended plan."

Given that the load growth attributable to the "Red Leaves Development" is contributing 6 to 8 MVA of load to the area that lead to the system expansion and the related investment, did Hydro One conduct an economic evaluation as required by Chapter 3 of the Distribution System Code? If "Yes", please provide the results of that economic evaluation including all assumptions and conclusions as well as an explanation as to why there is no "Recoverable" amount shown in the Table. If the answer is "No", please explain the reasons for not conducting such a study.

Response

No economic evaluation was conducted in relation to future load connections for this project. Rosseau DS is being constructed in order to relieve existing and forecasted overloads at Pinelands DS, Minett DS, and Horseshoe Lake DS which serve loads in the Lake Rosseau – Lake Joseph area. Residential and commercial growth associated with the Red Leaves Development is cited as an example of future load growth in the area. Economic evaluations will be carried out in the future for specific large customers or

expansion customers as required in accordance with the DSC and the cost of system capacity will be reflected in those calculations.

Ontario Energy Board (Board Staff) INTERROGATORY #89 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

89. Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: D27

With reference to:

i) Exhibit D2, Tab 2, Schedule 3, Investment Summary Reference: D27

ii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on June 5, 2009.

iii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on September 11, 2009.

In the Reference i) above, Hydro One stated in part that:

> "This investment is required to fund line upgrades, modifications, and transfers that are driven by generation connections but that are beneficial to Hydro One Distribution customers."

It is important to understand how the cost responsibility has been established in terms of the proposed guidelines on cost responsibility for the connection of generators to distributors outlined in Reference ii). It is also important to understand how the Board's revised proposed cost responsibility proposals in Reference iii), issued in September 11, 2009, may affect the cost responsibility whose results are reflected in the evidence shown in Reference i).

a) Please provide the number of generators expected to be connected under this Investment.

b) Please provide a break down of the costs shown in the Table in Reference i) (i.e., the $ 10.0 M for 2010 and $ 8.8 M for 2011), to reflect the amounts that are allocated to the various categories per the Board proposed guidelines outlined in Reference ii), by completing the following Table:

Costs

	2010 ($M)	2011 ($M)
Capital and Minor Fixed Assets	9.1	8.0
Operating, Maintenance & Administration and Removals	0.9	0.8
Gross Investment Cost	**10.0**	**8.8**
Connection		
Expansion		
Renewable Enabling		
Enhancement		

c) Please indicate whether the allocated amounts provided in responding to question b) would change assuming that the revised Board proposed guidelines on cost responsibility issued on September 11, 2009, see Reference iii) are in place for connecting generators to distributors. For clarity please reproduce the Table above, to show any changes in the four categories i.e., Connection, Expansion, Renewable Enabling, and Enhancement.

Response

a) As shown in Table 3 of Exhibit D1, Tab 3, Schedule 3 Hydro One Distribution forecasts 132 mid-size (i.e. between 500 kW and 10 MW) generation connections in 2010 and 272 such connections in 2011, 2 large-size generation connections (>10 MW) in each of 2010 and 2011, and 30 small-size generation connections (< 500 kW) in each of 2010 and 2011.

b)

	2010 ($M)	**2011 $M)**
Capital and Minor Fixed Assets	9.1	8.0
Operating, Maintenance & Administration and Removals	0.9	0.8
Gross Investment Cost	**10.0**	**8.8**
Connection	0	0
Expansion	9.1	8.0
Renewable Enabling	0	0
Enhancement	0	0

The information provided in the table above was revised as part of the update to the pre-filed evidence filed with the Board on September 25, 2009. The updated table is shown in the response to part c.

c) The updated table below reflects the evidence Hydro One filed on September 25, 2009 and shows the amounts allocated to the various categories per the Board's proposed DSC amendments noted in Reference iii), dated September 11, 2009

	2010 ($M)	**2011 $M)**
Capital and Minor Fixed Assets	17.8	16.7
Operating, Maintenance & Administration and Removals	0.9	0.8
Gross Investment Cost	**18.7**	**17.5**
Connection	0	0
Expansion	17.8	16.7
Renewable Enabling	0	0
Enhancement	0	0

As a result of the proposed DSC amendments issued by the Board on September 11, 2009, costs totaling $8.7M in each of 2010 and 2011 that were previously included

under external revenues as contestable line work for others became Expansion costs attributed to the Line Transfers & Upgrades program.

Ontario Energy Board (Board Staff) INTERROGATORY #90 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

90. Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: D28

With reference to:

i) Exhibit D2, Tab 2, Schedule 3, Investment Summary Reference: D28

ii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on June 5, 2009.

iii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on September 11, 2009.

In the above Reference i), Hydro One stated in part that:

> "The investment includes modifications (e.g. recloser installations, conductor renewals, new fuses) that will be beneficial to Hydro One Distribution customers and will therefore not be fully recovered from generators."

It is important to understand how the cost responsibility has been established in terms of the proposed guidelines in regard to cost responsibility for connecting generators to distributors outlined in Reference ii) which was issued on June 5, 2009. It is also important to understand how the Board's revised proposed cost responsibility proposals in Reference iii), issued in September 11, 2009, may affect the cost responsibility whose results are reflected in the evidence shown in Reference i).

a) Please provide the number of generators expected to be connected under this Investment.

b) Please provide a break down of the costs shown in the Table in Reference i) (i.e., the $ 61.7 M for 2010 and $ 124.9 M for 2011), to reflect the amounts that are allocated to the various categories per the Board proposed guidelines outlined in Reference ii), dated June 5, 2009, by completing the following Table:

	2010 ($M)	**2011 $M)**
Capital and Minor Fixed Assets	60.9	123.2
Operating, Maintenance & Administration and Removals	0.8	1.7
Gross Investment Cost	**61.7**	**124.9**
Connection		
Expansion		
Renewable Enabling		
Enhancement		

c) Please indicate whether the allocated amounts provided in responding to question b) would change assuming that the revised Board proposed guidelines on cost responsibility issued on September 11, 2009, see Reference iii), are in place for connecting generators to distributors. For clarity please reproduce the Table above, to show any changes in the four categories i.e., Connection, Expansion, Renewable Enabling, and Enhancement.

Response

a) See response to part a of Exhibit H, Tab 1, Schedule 89.

b)

	2010 ($M)	**2011 $M)**
Capital and Minor Fixed Assets	60.9	123.2
Operating, Maintenance & Administration and Removals	0.8	1.7
Gross Investment Cost	**61.7**	**125.0**
Connection	12.7	26.1
Expansion	16.1	32.4
Renewable Enabling	32.1	64.8
Enhancement	0	0

The information provided in the table above was revised as part of the update to the pre-filed evidence filed with the Board on September 25, 2009. The updated table is shown in the response to part c.

c) The updated table below reflects the evidence Hydro One filed on September 25, 2009 and shows the amounts allocated to the various categories per the Board's proposed DSC amendments noted in Reference iii), dated September 11, 2009

	2010 ($M)	**2011 $M)**
Capital and Minor Fixed Assets	83.2	145.6
Operating, Maintenance & Administration and Removals	0.8	1.7
Gross Investment Cost	**84.0**	**147.3**
Connection	12.7	26.1
Expansion	21.1	37.4
Renewable Enabling	49.5	82.1
Enhancement	0	0

As a result of the proposed DSC amendments issued by the Board on September 11, 2009, costs totaling $22.3M in each of 2010 and 2011 that were previously included under external revenues as contestable line work for others became part of Expansion and Renewable Enabling costs attributed to the Mid-size Generation Connections program.

Ontario Energy Board (Board Staff) INTERROGATORY #91 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

91. Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: D29

With reference to:

i) Exhibit D2, Tab 2, Schedule 3, Investment Summary Reference: D29

ii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on June 5, 2009.

iii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on September 11, 2009.

In the above Reference i), Hydro One stated in part that:

> "This investment is required to proactively install new breaker positions, add express feeders, and upgrade conductors and other feeder components to increase distribution system capacity to allow the connection of Distributed Generation (DG) to proceed quickly and efficiently."

It is important to understand how the cost responsibility has been established in terms of the proposed guidelines on cost responsibility for connecting generators to distributors outlined in Reference ii) which was issued on June 5, 2009. It is also important to understand how the Board's revised proposed cost responsibility proposals in Reference iii), issued in September 11, 2009, may affect the cost responsibility whose results are reflected in the evidence shown in Reference i).

a) Please provide the number of generators expected to be connected under this Investment.

b) Please check the amount cited for investment in 2011 as the Capital and Minor Fixed Assets of $ 87.0 million; plus the Operating, Maintenance & Administration and Removals of 97.4; yet the total is only $ 58.6 million.

c) Please provide a break down of the costs shown in the Table in Reference i) [i.e., the $ 35.4 M for 2010 and $ 58.6 M (subject to the error check) for 2011], to reflect the amounts that are allocated to the various categories per the Board proposed guidelines outlined in Reference ii), dated June 5, 2009, by completing the following Table:

Costs

	2010 ($M)	**2011 ($M)**
Capital and Minor Fixed Assets	31.6	87.0 (check for error
Operating, maintenance & Administration and Removals	3.8	97.4 (check for error)
Gross Investment Cost	**35.4**	**58.6(check for error)**
Connection		
Expansion		
Renewable Enabling		
Enhancement		

d) Please indicate whether the allocated amounts provided in responding to question c) would change assuming that the revised Board proposed guidelines on cost responsibility issued on September 11, 2009, see Reference iii), are in place for connecting generators to distributors. For clarity please reproduce the Table above, to show any changes in the four categories i.e., Connection, Expansion, Renewable Enabling, and Enhancement.

Response

a) See response to part a of Exhibit H, Tab 1, Schedule 89.

b) and c) A correction to the numbers and the requested breakdown is provided below.

Costs

	2010 ($M)	**2011 ($M)**
Capital and Minor Fixed Assets	31.6	87.0
Operating, maintenance & Administration and Removals	3.8	10.4
Gross Investment Cost	**35.4**	**97.4**
Connection	0	0
Expansion	31.6	87.0
Renewable Enabling	0	0
Enhancement	0	0

d) The proposed DSC amendments issued by the Board on September 11, 2009 did not change the numbers provided in the table above.

Ontario Energy Board (Board Staff) INTERROGATORY #92 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

92. Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: D30

With reference to:

i) Exhibit D2, Tab 2, Schedule 3, Investment Summary Reference: D30

ii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on June 5, 2009.

iii) The Board's "Notice of Proposal to Amend a Code", File Number EB-2009-0077, issued on September 11, 2009.

In the above Reference i), Hydro One stated in part that:

> "This investment is required to proactively install protections and controls on the distribution system to allow the connection of Distributed Generation (DG) to proceed quickly and efficiently.
>
> Not proceeding with this investment would result in generation connections being delayed due to the sub-optimal, one-at-a time implementation of protection and control infrastructure on the distribution system as funded by individual generator proponents.
>
> ….To allow generation to connect to feeders fed from Distribution Stations without reducing load supply reliability, it is necessary to upgrade the protective devices (reclosers) in those stations. Upgrades will allow these devices to sense the direction of current feeding into faults, sense the impedance to the fault, and provide coordinating trip signals to appropriate generators to prevent islanding and fuse damage.
>
> ….It will also be necessary to provide load rejection facilities at the Distributing Stations to maintain the functionality of Special Protection Schemes and Under Frequency Load Shedding schemes required for the reliability of the Bulk Power System. These schemes must be very fast-acting and presently operate by tripping feeder breakers at Transmission Stations (TSs)."

It is important to understand how the cost responsibility has been established in terms of the proposed guidelines on cost responsibility for connecting generators to distributors outlined in Reference ii) which was issued on June 5, 2009. It is also important to understand how the Board's revised proposed cost responsibility

proposals in Reference iii), issued in September 11, 2009, may affect the cost responsibility whose results are reflected in the evidence shown in Reference i).

a) Please provide the number of generators expected to be connected under this Investment

b) Please provide a break down of the costs shown in the Table in Reference a) (i.e., the $ 21.1 M for 2010 and $ 36.8 M for 2011), to reflect the amounts that are allocated to the various categories per the Board proposed guidelines outlined in Reference ii), dated June 5, 2009, by completing the following Table:

Costs

	2010 ($M)	**2011 ($M)**
Capital and Minor Fixed Assets	21.1	36.8
Operating, maintenance & Administration and Removals	-	-
Gross Investment Cost	**21.1**	**36.8**
Connection		
Expansion		
Renewable Enabling		
Enhancement		

c) Please indicate whether the allocated amounts provided in responding to question b) would change assuming that the revised Board proposed guidelines on cost responsibility issued on September 11, 2009, see Reference iii), are in place for connecting generators to distributors. For clarity please reproduce the Table above, to show any changes in the four categories i.e., Connection, Expansion, Renewable Enabling, and Enhancement.

Response

a) Please refer to Exhibit H, Tab1, Schedule 89, part a).

b)

	2010 ($M)	**2011 $M)**
Capital and Minor Fixed Assets	21.1	36.8
Operating, Maintenance & Administration and Removals	0	0
Gross Investment Cost	**21.1**	**36.8**
Connection	0	0
Expansion	0	0
Renewable Enabling	21.1	36.8
Enhancement	0	0

c) The proposed DSC amendments issued by the Board on September 11, 2009 did not change the numbers provided in the table above.

Ontario Energy Board (Board Staff) INTERROGATORY #93 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

93. Ref: ExhD2/Tab2/Sch3/Investment Summary Reference: D35

Hydro One proposes the installation of Smart Grid pilot facilities in one part of its service area. Hydro One states that it intends to establish a Smart Zone in the Owen Sound area to test the new technologies before they are launched for a wider deployment. Some of the Smart Grid projects proposed by Hydro One are; a) Energy storage pilot in the Smart Zone and/or remote areas; b) Plug-in Hybrid Vehicle (PHEV) trials; and c) Other devices like feeder ties, monitoring devices and smart switches. With these initiatives Hydro One hopes to:

- improve the reliability of the distribution system and also improve customer satisfaction;
- provide a more proactive response to system faults;
- provide more effective system monitoring to support system planning; and
- increase operational efficiencies to respond to outages and to carry out service restoration.

a) Considering that much of Hydro One's service area is very rural in nature, will lessons learned from the Owen Sound Smart Grid pilot be applicable over its entire service area with respect to fault detection and the restoration of remote rural feeders? If they are applicable, explain in detail the nature of the similarities.

b) Considering that many PHEV applications in Ontario are expected to be in urban high-density environments, will lessons leaned from the Owen Sound Smart Grid pilot concerning these vehicles be applicable in high density built up areas? If they are applicable, explain in detail the nature of the similarities.

c) One of the main government goals for the Smart Grid is to further enable demand reduction opportunities in the home and in businesses by providing more energy usage and cost information to consumers and giving "LDC Control Rooms" more information about these potential residential and business Demand Reduction (DR) opportunities. Since no mention has been made of these potential DR opportunities, can Hydro One explain why this is the case in their Pilot project?

d) If Hydro One does have some DR projects in its Smart Grid portfolio, please explain in detail the nature of these initiatives.

e) Since Hydro One has indicated in its evidence that it has some projects in its Smart Grid Pilot study related to energy storage, please explain in detail the nature of these initiatives.

Response

a) Yes, lessons learned from the Owen Sound Smart Grid pilot are expected to be applicable over Hydro One's entire service area with respect to fault detection and the restoration of remote rural feeders. The pilot territory extends 120 km by 120 km and was chosen because of its diversity. It includes a variety of features common throughout Hydro One's service territory such as a city (Owen Sound), seasonal customers on the Bruce Peninsula, farm customers near Meaford, rural customers, several TS's (Owen Sound TS, Meaford TS), a number of DS's and a number of active distributed generation sites. The approach will be to target demographic groups present throughout this territory to best understand impacts on Hydro One.

b) The PHEV trials have two areas of focus. First is to learn about the impact on Hydro One's fleet using batteries to power hydraulics in lift devices (bucket trucks) rather than the continuous running of the diesel engines. Second is how PHEV's might impact distribution transformer planning (assess the change to loading and load diversity). This information will be useful to all utilities, including high density built up areas.

c) There are two scenarios planned where Demand Reduction (DR) technologies will be examined as part of the Smart Grid Pilot.
   1) First is in Distributed Generation (DG) integration and whether DR can be utilized to control load as an avenue to supplement power quality recognizing at times DG can be highly variable.
   2) The second scenario focuses on Customer Enablement. Customers will be migrated to time of use rates beginning in 2010 – this scenario is intended to reach out to the market place to provide customers with innovative tools to help them manage their bills while also contributing to the provincial goals of energy conservation. As such there is a need for:
      i) Broad array of technology / products including, but not limited to, two-way communicating programmable thermostats, In-home Energy Displays (IHD) and remote appliance controllers (such as smart appliance controllers, multi purpose gateways, etc.) that utilize the deployed smart meter network.
      ii) IHDs for CDM and planned outage / other notifications using the two way communication.
      iii) Web and / or local presentment of information over a variety of media devices.
      iv) The ability to monitor and assess customer response to and acceptance of these devices.

v) The assessment of and development distribution channels and provisioning of devices.
vi) Evaluation, monitoring and verification of conservation and demand response results.

d) As detailed above, there are two business scenarios that will be developed in the Smart Zone involving DR. The process to develop these start with the description of requirements (summarized above), the tender for proposals (RFP), followed by a limited implementation in the Smart Zone to test viability prior to broader deployment.

e) As part of Hydro One's Smart Grid RFP, we are expecting respondents to provide solutions that include energy storage options (e.g. for power quality and DG optimization). Specifics on those options will follow the RFP process. In addition, Hydro One is working with many stakeholders and partners to complete several energy storage project applications to the Federal Government as part of the Federal Government's Clean Energy Fund program. These are as follows:
1) A fuel cell application led by Powertech with Hydro One, Manitoba Hydro, Hydro Quebec and Department of National Defense as key stakeholders along with GE and other consultants.
2) A small scale biomass Combined Heat and Power (CHP) project being led by CEATI with Hydro One, BC Hydro, Manitoba Hydro, Toronto Hydro, Ontario Centres of Excellence, Ryerson University, and industry.
3) A small battery storage project capturing excess energy at night and releasing it during the day. This project is being led by CEATI with Hydro One, Manitoba hydro, Cornwall electric, Toronto hydro, Ontario Centres of Excellence, University of Manitoba, Manitoba Research Center, Ryerson University along with Electrovaya (the battery vendor) and Verdant Power.

Ontario Energy Board (Board Staff) INTERROGATORY #94 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD1/Tab3/Sch6/p1

Table 2 on this page shows total IT capital costs from 2006 to 2011, but only shows Dx allocations for the two test years. Please provide the Dx allocations for 2006 to 2009 for all the categories in the table. Please provide the same information for Table 3 (page 4), Table 4 (page 6) Table 5 (page 10) and Table 1 (Schedule 8, page 1).

Response

Table 2
Total IT Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test	
	2006	2007	2008	2009	2010	2011
Software Refresh & Maintenance	3.8	5.2	4.1	4.1	3.5	3.5
Minor Fixed Asset Program	7.5	8.2	5.3	4.2	11.7	10.1
Development Programs	8.0	4.9	0.5	5.5	4.8	3.9
Total	**19.3**	**18.3**	**9.9**	**13.9**	**20.0**	**17.5**

Table 3
Software Refresh and Maintenance Program Capital Expenditures
($ Millions)

Description	Historic			Bridge	Test	
	2006	2007	2008	2009	2010	2011
Software Refresh & Maintenance	0.4	5.2	4.1	4.1	3.5	3.5
Windows (O/S)	3.3	-	-	-	-	-
Total	**3.8**	**5.2**	**4.1**	**4.1**	**3.5**	**3.5**

Table 4
Minor Fixed Asset Program Capital Expenditures
($ Millions)

Description	Historic			Bridge	Test	
	2006	2007	2008	2009	2010	2011
IT Mainframe, Servers and Storage	2.7	4.8	0.9	1.0	3.5	2.4
IT Desktops, Laptops, Tablets, Printers and Plotters	3.4	2.7	3.0	1.5	3.6	3.5
Telecom Networks and PBX/Voicemail	1.5	0.7	1.4	1.7	4.6	4.2
Total	**7.5**	**8.2**	**5.3**	**4.2**	**11.7**	**10.1**

Table 5
IT Development Projects Capital Expenditures
($ Millions)

Description	Historic			Bridge	Test	
	2006	2007	2008	2009	2010	2011
CIS/CSS Hybrid Upgrades/CRM	0.4	2.9	0.3	-	-	-
CTI Upgrades	3.3	0.7	(0.3)*	-	-	-
APCI/WEP	3.5	0.4	-	-	-	-
IREIS	-	-	-	0.1	-	-
Mobile IT	-	-	-	0.4	1.3	1.3
Asset Mgmt & Data Collection	0.8	0.9	-	-	-	-
Warehouse Bar Coding	-	-	-	0.9	0.4	-
eCustomer Self-Service Web Site	-	-	-	3.4	-	-
Enterprise GIS Program	-	-	-	-	2.7	2.6
DX Asset Information System	-	-	0.5	0.7	0.4	-
Total	**8.0**	**4.9**	**0.5**	**5.5**	**4.8**	**3.9**

* represents vendor credit

Exhibit D1, Tab 3, Schedule 8

Table 1
Total Facilities and Real Estate and Security Infrastructure Capital Expenditures
($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Major	1.7	4.6	3.0	9.0	23.2	23.5
MFA	0.4	1.8	0.6	0.9	5.8	5.3
Total	**2.1**	**6.4**	**3.6**	**9.9**	**29.0**	**28.8**

Ontario Energy Board (Board Staff) INTERROGATORY #95 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

95. Ref: ExhD1/Tab3/Sch6/p1

IT capital allocated to distribution grows from $10 million in 2008 to $20 million in 2010, an increase of 100%. The exhibit provides evidence of numerous projects that contribute to this increase. Did Hydro One consider a more phased approach to these projects to reduce the impact in the test years? Please rank the major IT projects in order of importance/impact on Hydro One operations.

Response

Minor fixed assets and development projects contribute to this increase.

Minor fixed asset (MFA) expenditure is driven by a phased lifecycle refresh program of IT infrastructure components such as servers, mainframe, desktops, laptops, printers and telecom equipment. Funding requirements vary year over year depending upon hardware lifecycles.

The 2010 development projects contributing to this increase include Enterprise GIS Program, Mobile IT and Warehouse Bar Coding. All three projects are following a phased approach with their start-dates coordinated with the Cornerstone SAP Phase 2 implementation.

IT investments are made in accordance with approved business strategies and follow the IT governance process and takes into consideration business need and resource availability when setting priority of projects.

Ontario Energy Board (Board Staff) INTERROGATORY #96 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD1/Tab3/Sch8/p4

Hydro One is increasing Facilities, Real Estate and Security Infrastructure by almost 800% from 2008 to 2010. Much of the increase is attributable to new head office space and other improvements to offices and service centers. Why has Hydro One neglected accommodation investments until the test years? Please demonstrate why Hydro One needs to suddenly move on these investments in 2010 after historically neglecting this investment from 2006 onward? Did Hydro One consider the potential savings of moving the head office space outside of downtown Toronto? What were the results of that consideration?

Response

From 1999 – 2004 Hydro One undertook a business strategy to rationalize facilities and space requirements. This included facilities of Municipal Electric Utilities acquired throughout the Province. The Rationalization Program examined space utilization, associated operating costs and organizational-field requirements. The Program concentrated on consolidation and optimization efforts in terms of providing best value-space solutions for the company, while decisions were made and executed with regards to site retention or disposal of underutilized, high cost sites / facilities. During this Rationalization Program period, Hydro One deferred significant capital investments in facilities until the rationalization program completion. Subsequently, a facilities assessment with Line of Business was undertaken to determine planned strategy to deal with service centres, which were determined to be at or near the end of their life, inadequate for changing business needs or which historically were experiencing health and safety issues.

The aging facilities asset base in conjunction with the emerging accommodation needs from the development and growth of Company work programs / initiatives, e.g. Distributed Generation and the Green Energy Act and operational needs of the business units requires capital investment in order to continue to provide adequate workspace accommodation. In addition to field requirements, the Hydro One Networks head office lease will be ending on January 31, 2010. The existing premises are approximately 25 years old and the interiors are in need of upgrade and/or replacement. Within the recently completed lease renewal of 483 Bay, Hydro One was successful in obtaining the commitment of the Landlord to upgrade base building systems/infrastructures, allowances for tenant improvements and swing space to execute improvements over a

two year period, which created both the opportunity and incentive to complete head office related improvements at this time.

Leading to the decision to renew the lease for 483 Bay Street through a competitive process, a commercial real estate firm was retained to assist Hydro One with the identification, evaluation and negotiations for office space requirements. The retained firm undertook to directly investigate through a formal RFP process with landlords and real estate brokers leasing opportunities, which included advertisement through a major newspaper, to meet Hydro One Networks' objectives within the Greater Toronto area. Of the eleven office space proposals received, a comparative analysis process was undertaken of five short listed options.

The comparative analysis covered wide set of criteria which included price, transit access; LEED/environmental accreditation; telecommunications, barrier free access; amenities; floor plate configuration and efficiency; elevators; growth opportunities; security; and building services were also considered. Ultimately the process identified two Downtown Toronto options with landlords that were well suited to meet Hydro One Networks' requirements. Hydro One Networks pursued parallel negotiations with the respective landlords including validation of the lease terms and pricing in the market place at that point in time.

Ontario Energy Board (Board Staff) INTERROGATORY #97 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD1/Tab3/Sch8/p6

The Table on this page shows no capital spending on Security Infrastructure from 2006 to 2009, with a sudden spending of $12.5 million in 2010 that continues to 2011. Why is there a sudden jump in this spending in the test year? Where was security infrastructure capital spending previously reported? Please provide the comparable spending levels from 2006 to 2009.

Response

Safety, security, and reliability have always been a priority at Hydro One. In the past, the cost for basic security was built into our asset projects. However, risks to the electricity infrastructure have increased due in part to two economic/societal trends - the increased demand in base metals (primarily copper) and the increase in domestic extremism. As such, we have implemented a new program to upgrade our stations to better protect them against crime.

Security Infrastructure is a new program that begins in 2010. Therefore there are no comparable spending levels from 2006 to 2009.

The main purpose of this new security program is to upgrade perimeter security to deter criminal activity as well as prevent animal intrusions, a safety concern and cause of power outages at some stations. In recent years, Hydro One has experienced a significant increase in criminal acts of theft and mischief that have targeted its electricity infrastructure and threatened the reliability of the electricity delivery system.

Ontario Energy Board (Board Staff) INTERROGATORY #98 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD1/Tab3/Sch9/p2

The Table on this page shows a 156% increase in Transportation and Work Equipment capital expenditures from 2008 to 2010. Is Hydro One capable of efficiently executing such a massive increase in this procurement of $133.3 million in the test year? What steps has Hydro One taken to address this issue?

Response

Hydro One is confident that the prudent procurement of Transport & Work Equipment in 2010 will be achieved.

Fleet Services is continuously working with our vendors to ensure that they are a part of our long term plans, and have upfront knowledge and longer term lead times to maximize their scheduling and build capacity.

Hydro One has also standardized Transport & Work Equipment specifications to optimize purchasing capacity and efficiency. Fleet Services, together with Hydro One's Strategic Sourcing Initiatives Group are continuously monitoring and reviewing the opportunities and potential challenges posed by the broader global markets.

The overall growth and demands of the SD&O work programs necessitate the acquisition of Transport and Work Equipment in a timely and efficient manner. Fleet Services will continue to monitor and evaluate the requirements of the demand-driven work programs as they evolve, and we will be in the position to respond to the changing needs accordingly.

Ontario Energy Board (Board Staff) INTERROGATORY #99 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

99. Ref: ExhD1/Tab3/Sch7/p2

Table 1 shows the total capital cost of Cornerstone from 2007 to the test years. Total capital spending from 2007 to 2009 is $273 million with another $44.8 million planned for 2010 and 2011.

a) Please provide a table that compares this capital spending and savings estimate with those presented in the EB-2007-0681 and the EB-2005-0378 rates cases. If these amounts differ significantly, please explain the reasons for the differences.

b) In particular, the Cornerstone capital spending for 2008 approved in rates in EB-2007-0681 was $63 million while this application shows 2008 actual spending of $107.1 million. What are the reasons for such a large increase in capital spending in excess of applied for amounts??

Response

a) The following table is an extension of Table 1 in Exhibit D1 Tab 3 Schedule 7, showing the set of costs as submitted in rate filings EB-2009-0096 and EB-2007-0681. The cost estimates provided in EB-2005-0378 identified planned upgrade work for some of the existing systems that were eventually part of the Cornerstone program, but Cornerstone was not identified as such in this filing.

Regarding savings, EB-2005-0378 did not provide estimated savings related to Cornerstone. Although EB-2007-0681 estimated Phase 1 savings at 200M over 2008 – 2015, we were not able at that time to provide a breakdown by year. Savings estimates for Phases 2 – 4 were similarly not available at that time.

Table H-1-99: Capital Cost Comparison (EB-2009-0096 and EB-2007-0681)

	Historic			**Bridge**	**Test**		**Allocated to Distribution**	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2010**	**2011**
Minor Fixed Assets								
EB-2009-0096	**0**	**3.2**	**7.2**	5.3	1.3	1.5	0.7	0.8
EB-2007-0681	**n/a**	**n/a**	**n/a**	n/a	n/a	n/a		
Development Projects								
EB-2009-0096	**0**	**60.4**	**99.9**	97.2	22.7	19.3	10.0	8.5
EB-2007-0681	**0**	**60.4**	**63.0**	n/a	n/a	n/a		
Total Capital Cost								
EB-2009-0096	**0**	**63.6**	**107.1**	102.5	24.0	20.8	10.7	9.3
EB-2007-0681	**0**	**60.4**	**63.0**	n/a	n/a	n/a		
Savings								
EB-2009-0096	**0**	**0**	**0**	(8.0)	(10.5)	(19.9)	(3.1)	(6.1)
Net Capital Cost								
EB-2009-0096	**0**	**63.6**	**107.1**	**94.5.**	**13.5**	**0.9**	**7.6**	**3.2**

b) The estimates in EB-2007-0681 included costs only for Cornerstone Phase 1. Phases 2 & 3 were in the planning stage at that time. Estimates in EB-2009-0096 include costs for all 3 Phases. The $63M for 2008 in EB-2007-0681 included estimated costs only for Cornerstone Phase 1. In EB-2009-0096, the 2008 costs are actual costs for both Phases 1 & 2.

Ontario Energy Board (Board Staff) INTERROGATORY #100 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD1/Tab3/Sch7/p2 & p 5

Two different Cornerstone savings amounts for the test years (both O&M and Capital) are found at Table 1 on page 2 and at Table 2 on page 5. Different numbers for O&M Cornerstone savings are found at Exhibit C1/Tab2/Schedule10/p1. And at Exhibit A/Tab16/Schedule1/p5 another table with Cornerstone savings is presented with another set of values. Please reconcile or explain why all these estimates differ.

Response

The tables in Exhibits A, C and D show the same Cornerstone savings information from different perspectives.

The expected Cornerstone savings tabled in both Exhibit C1, Tab 2, Schedule 10 and Exhibit D1, Tab 3, Schedule 7 are the OM&A and Capital savings in each year. The total savings is the sum of the contribution from each of the three Cornerstone phases.

The Cornerstone savings indentified in Table 1 Exhibit A, Tab 16, Schedule, 1, page 5 are the year over year incremental savings. The sum of the rows in Table 1 Exhibit A, Tab 16, Schedule, 1, page 5 reconciles with the values shown in the Tables in Exhibit D1, Tab 3, Schedule 7, and Exhibit C1, Tab 2, Schedule 10. Any differences are due to numerical rounding.

A reconciliation of the Exhibits is provided in the following table:

Cornerstone Savings ($M)

Table Reference		Test		Allocation to Distribution	
		2010	2011	2010	2011
All Phases					
C1/2/10 Table 1	OM&A	(15.6)	(27.9)	(5.3)	(8.6)
D1/3/7 Table 1	Capital	(10.5)	(19.9)	(3.1)	(6.1)
Phase 1					
D1/3/7 Table 2	OM&A	(13.0)	(16.5)		
	Capital	(9.2)	(11.8)		
	Total	(22.2)	(28.3)		
Phase 2					
D1/3/7 Table 3	OM&A	(2.6)	(3.2)		
	Capital	(1.3)	(2.3)		
	Total	(3.9)	(5.5)		
Phase 3					
D1/3/7 Table 4	OM&A	0.0	(8.2)		
	Capital	0.0	(5.8)		
	Total	0.0	(14.0)*		
All Phases					
A/16/1 p.5	OM&A			(5.3)	(8.6)
	Capital			(3.2)	(6.2)

* Note: Table 4 Exhibit D1, Tab 3, Schedule 7, page 11 is corrected as follows:

Table 4
Total Cornerstone Phase 3 Savings ($M) (Transmission & Distribution)

	2010	2011
OM&A	0	8.2
Capital	0	5.8
Total	0	14.0 *

Ontario Energy Board (Board Staff) INTERROGATORY #101 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD2/Tab2/Sch3/Cornerstone Phase 2 - Investment Summary Reference: IT1

Hydro One states that Cornerstone Phase 2 will bring the following business benefits to Hydro One:

- *Critical Finance & Payroll functions will be moved to a fully vendor-supported environment*
- *Hydro one will avoid prolonged reliance on temporary financial interfaces between SAP and PeopleSoft*
- *One integrated system of record for all asset and financial data.*

a) Please confirm whether from the corporate perspective, the project is part of "Information Management & Information Technology".

b) Indicate which business units (Transmission, Distribution, Remotes…etc) will benefit from the project.

c) If more than one business unit would benefit from the project, what is the contribution of each towards the cost of Phase 2 of the Cornerstone project?

d) Has Cornerstone Phase 2 been completed? If No, please provide an update as to when completion is expected.

e) For the business benefits, i.e., savings, please quantify the savings in total and for each business unit (Transmission, Distribution, Remotes, ..etc).

f) For the various savings addressed in responding to Question e), please describe how the savings are calculated, the projected accuracy bandwidth for future savings and the risk factors for savings non achievement.

g) How does the updated Rudden allocation study affect these savings calculations?

Response

a) Cornerstone is an Enterprise Asset Management capital project replacing several of Hydro One's core business systems as they reach their end of life. Once the Cornerstone project is commissioned in service, it will be managed as a shared service under Hydro One's Information Technology work programs.

b) All Hydro One Networks business units benefit from the Cornerstone project as it replaces end of life core business systems. The specific benefits/savings to the core distribution and transmission businesses have been presented in the evidence of this rate case.

c) Please refer to Exhibit H, Tab 7, Schedule 71.

d) The majority of Cornerstone Phase 2 is complete. The core business systems of Cornerstone Phase 2 went live on August 5, 2009. The completion of the IFRS compliance requirement is targeted for 2011.

e) Total Phase 2 savings are to be $50M. The transmission and distribution split for years 2010 and 2011 is as follows.

	Projected Phase 2 Savings ($M)	
	2010	2011
Transmission	2.9	3.7
Distribution	1.0	1.8
Total	3.9	5.5

f) The predominate risk factor (before the Cornerstone implementation) was taking "no action". This would mean the business was operating on software no longer supported by the vendor. Mitigating this over riding risk factor required systems-replacement. Benefits associated with the SAP implementation were identified following the systems replacement decision.

g) The Black and Veatch (previously Rudden) Review of Shared Services Cost Methodology study does not affect Cornerstone savings. The purpose of the allocation methodology is to allocate Common Functions and Services department costs. Cornerstone savings are specifically attributed to Transmission and Distribution and not allocated by the Black and Veatch study.

Ontario Energy Board (Board Staff) INTERROGATORY #102 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD2/Tab2/Sch3/Cornerstone Phase 3 - Investment Summary Reference: IT2

To understand the benefits, of project where the "Results" in the evidence states that Cornerstone Phase 3 will bring the following business benefits to Hydro One:

- *Provide SAP integration to operating, scheduling/dispatch and GIS system using mobile technology*
- *Provide specialized RCM software application to monitor/analyze preventative maintenance results, validate asset models, and facilitate strategic/scenario planning that is focused on improving asset lifecycle management decisions*
- *Consolidate and eliminate duplicative end-user databases/applications*
- *Streamline processes and improve information transparency.*

a) For the business benefits, i.e., savings, listed in the evidence please quantify these savings in total and for each business unit (Transmission, Distribution, Remotes, ..etc).

b) For the various savings addressed in responding to Question a) above, please describe how the savings are calculated, the projected accuracy bandwidth for future savings and the risk factors for savings non achievement.

c) How does the updated Rudden allocation study affect these savings calculations?

Response

a) and b)

Cornerstone Phase 3 is comprised of several individual initiatives with discrete savings. Phase 3 is currently in the detailed planning phase. Scope, cost estimates and related savings for each of the planned Phase 3 initiatives will be better defined before the end of Q1 2010. A breakdown of the projected savings will be available at that time.

Hydro One anticipates a savings of $4M to the distribution business in 2011, from the rollout of the Phase 3 initiatives.

c) The Black and Veatch (previously Rudden) Review of Shared Services Cost Methodology study does not affect Cornerstone savings. The purpose of the allocation methodology is to allocate Common Functions and Services department costs. Cornerstone savings are specifically attributed to Transmission and Distribution and not allocated by the Black and Veatch study.

Ontario Energy Board (Board Staff) INTERROGATORY #103 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD2/Tab2/Sch3/GIS Implementation - Investment Summary Reference: IT5

To understand the benefits, of project where the "Results" in the evidence states that GIS Implementation will bring the following business benefits to Hydro One:

- *Improved Decision Quality:* Provide immediate access to more comprehensive and integrated spatial asset and connectivity data in corporate systems, contributing to consistency and timeliness in asset planning, maintenance and outage decisions.
- *Improved Safety:* Provide access to reliable, accurate and up-to-date data regarding the state of the network, which empowers work crews to work more safely.
- *Reduced Litigation:* Provide access to a single, seamless and up-to-date repository of records from which organization can avoid and defend against litigation for land usage.
- *Prevent Rework:* Provide a single, seamless repository of spatial records which are updated by appropriate LOBs to eliminate the need for each LOB to maintain its own spatial data.
- *Support Next Generation Applications:* Provide access to network properties.

a) For the business benefits, i.e., savings, please quantify these savings in total and for each business unit (Transmission, Distribution, Remotes, ..etc).

b) For the various savings addressed in responding to Question a) above, please describe how the savings are calculated, the projected accuracy bandwidth for future savings and the risk factors for savings non achievement.

c) How does the updated Rudden allocation study affect these savings calculations?

Response

a) The business benefits of the Enterprise GIS Program are further explained in Exhibit D1, Tab 3, Schedule, 6, page 13-14 and include improvements to outage restoration and distribution system reliability in terms of GIS being the foundational technology for smart grid applications. As such, business benefits go beyond cost savings. In regards to cost savings, Hydro One engaged a consultant in 2008 to help produce a GIS strategy and roadmap. Based on this study, high-level costs were projected at

$27M with benefits of $17M for the five year period. Leveraging this strategy, Hydro One subsequently developed a program estimated at $20.9M and approximate savings of $1M starting in 2011 and phasing in to approximately $3M per year thereafter as data consolidation is completed. Savings are predominantly allocated to the Distribution business.

b) Savings are based on the elimination of redundant data maintenance work processes, automating the production of operating maps, and improved field decision support to optimize and avoid extraneous field visits. The accuracy bandwidth for these projections is +/- 50% at this time. Risk factors for savings non-achievement that are to be mitigated as part of program delivery:
- Unavailable funding;
- Technology non-performance (issues with system integration, software, telecommunications);
- Data unavailability;
- Higher than anticipated new data management processes costs.

c) The Black and Veatch (previously Rudden) Review of Shared Services Cost Methodology study does not affect Cornerstone savings. The purpose of the allocation methodology is to allocate Common Functions and Services department costs. Cornerstone savings are specifically attributed to Transmission and Distribution and not allocated by the Black and Veatch study.

Ontario Energy Board (Board Staff) INTERROGATORY #104 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD2/Tab2/Sch3/Real Estate Field Facilities - Investment Summary Reference: C1

a) Please provide the amount of investments in Real Estate Field Facilities, in $ millions, for the historical years 2006 – 2008 and the 2009 Plan.

b) Please provide quantification of the additional investments in 2010 and 2011 that is over and above what would the level have been absent the activities attributed to the Green Energy Act.

Response

a) The historical investments for Real Estate Field Facilities years 2006 – 2008 and planned 2009 expenditures are summarized in the table below.

Real Estate Field Facilities ($ Million)	**Year**	**2006 actual**	**2007 actual**	**2008 actual**	**2009 planned**
	Major	$2.8	$5.4	$5.8	$20.2
	MFA	$0.6	$1.5	$0.0	$1.2
	Total	**$3.4**	**$6.9**	**$5.8**	**$21.4**

b) The Company estimates approximately $14M in 2010 and $13M in 2011 in additional investment needs that are required to provide for new accommodation solutions, address need for new buildings, building additions and facilities improvements in order to continue to provide adequate space to support work programs. This does not include impact on additional accommodation needs in the field as result of Green Energy Act, Distributed Generation and modernization of distribution system work initiatives

Ontario Energy Board (Board Staff) INTERROGATORY #105 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD2/Tab2/Sch3/Real Estate Head Office and GTA Facilities – Investment Summary Reference: C2

a) Please provide the amount of investment in Real Estate Head Office and GTA Facilities, in $ millions, for the historical years 2006 – 2008 and the 2009 Plan.
b) Please provide quantification of the additional work space which would be required in the future due to the anticipated increase in work activities due to the Green Energy Act that is in addition to the amount stated in the Reference as 280,000 square feet, where the evidence stated in part that:

> *"A survey of the various business units in May 2008 identified a requirement for approximately 280,000 square feet of office space for Hydro One Networks Head Office."*

Response

a) The historical investments for Head Office and other Administrative Facilities within GTA including planned 2009 expenditures are summarized in the table below.

$ Million	Year	**2006 actual**	**2007 actual**	**2008 actual**	**2009 planned**
Head Office Facility*	Major	$0.0	$0.7	$0.3	$0.0
	MFA	$0.0	$0.9	$0.9	$0.3
	subtotal	**$0.0**	**$1.6**	**$1.2**	**$0.3**
GTA Administrative Facilities	Major	$0.2	$0.4	$0.0	$0.3
	MFA	$0.0	$0.7	$0.1	$0.0
	subtotal	**$0.2**	**$1.1**	**$0.1**	**$0.3**
Total		**$0.2**	**$2.7**	**$1.3**	**$0.6**

* Note: 'Head Office Facility' referenced in the table above includes Atrium on Bay space (40,000 sq feet) which is not included in the 483 Bay Street head office space (280,000sq feet) .

b) The Company currently estimates minimum of $5M in 2010 and $4.5M in 2011 in additional investments required to secure leased administrative office space within the GTA mainly due to the Green Energy Act. The assessment of space needs continues, in cooperation with the respective business units, and will clarify (as more information become available) the requirements associated with the increasing work program, especially the requirements resulting from the implementation of the Green Energy Act, the modernization of distribution systems and connecting distributed generation.

Ontario Energy Board (Board Staff) INTERROGATORY #106 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref: ExhD2/Tab2/Sch3/Service Equipment - Investment Summary Reference: C3

a) Please provide the total investment for Hydro One Networks Inc. in $ millions for this category "Shared Services Capital-Service Equipment" for the historical years 2006 – 2008 and the 2009 Plan as well as for the 2010 and 2011.

b) Please provide the split of the total investments established in response to a) above, between the various business units (Transmission, Distribution, Remotes, …etc).

Response

a) and b)

Below is the total investment for Hydro One Networks Inc for the category "Shared Services Capital - Service Equipment for 2006 through to 2011, as well as the split between distribution and transmission for the periods. These amounts do not include investments for Hydro One Remotes.

Hydro One Networks Inc. (Transmission & Distribution)

M$	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
Service Equipment	3.9	7.9	11.7	12.1	12.0	8.8
Distribution	2.2	4.5	6.7	6.9	6.8	5.0
Transmission	1.7	3.4	5.0	5.2	5.2	3.8

Ontario Energy Board (Board Staff) INTERROGATORY #107 List 1

Interrogatory

Issue 4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

107. Ref: ExhD2/Tab2/Sch3/Transport and Work Equipment - Investment Summary
Reference: C4

a) Please provide the total investment for Hydro One Networks Inc. in $ millions for this category "Shared Services Capital-Transport & Work Equipment" for the historical years 2006 – 2008 and the 2009 Plan as well as for the 2010 and 2011.

b) Please provide the split of the total investments established in response to a) above, between the various business units (Transmission, Distribution, Remote…etc).

Response

a) & b) Below is the total investment for Hydro One Networks Inc for the category "Shared Services Capital - Transport & Work Equipment for 2006 through to 2011, along with the split between distribution and transmission for the periods. These amounts do not include investments for Hydro One Remotes.

Hydro One Networks Inc. (Transmission & Distribution)

	2006	2007	2008	2009	2010	2011
Transport & Work Equipment - Total	41.3	41.1	52.0	39.7	133.4	74.1
Distribution Total	31.3	31.2	39.5	30.2	101.4	56.3
Transmission Total	10.0	9.9	12.5	9.5	32.0	17.8

Ontario Energy Board (Board Staff) INTERROGATORY #108 List 1

Interrogatory

Issue 4.6 Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the distribution system assets and support the O&MA and Capital expenditures for 2010/2011?

Ref: ExhD1/Tab2/Sch1/p1,7,17 and
EB-2007-0681; Response to Board Staff IR #14

In its Response to Board Staff IR #14 in the EB-2007-0681 proceeding, Hydro One states that the "analysis engine" that it uses to assess and categorize its assets was provided by Acres International (now Hatch Energy).

a) What other organizations are using the Acres product for Asset Management assessments and what has been their experience with it?

b) Has Hydro One validated this analysis model in any way and if not, why not?

c) If this analysis model indicated (falsely) that 10% of a certain class of equipment was near end of life (categorized as very poor) rather than say 20% being in this category: 1) how would this anomaly come to the attention of Hydro One, 2) how would Hydro One deal with this situation; and 3) what would be the likely consequences of this incorrect categorization?

d) Did the Acres asset analysis model "alert" Hydro One to the fact that there was a sub-class (red pine) of wooden distribution poles that was deteriorating at a faster than normal rate and if not, why not?

Response

a) Acres and Hatch have provided ACA methods and models to various utilities including Hydro Quebec, British Columbia Transmission Corporation, New York Power Authority, Yukon Energy, and Orangeville Hydro. With respect to the Acres' methodology, Hydro One Distribution's has not formally discussed ACA experiences with these utilities.

b) Acres last conducted ACA studies for Hydro One Distribution in 2005. Since that time, Hydro One Distribution has been using the Acres methodology as its basic ACA approach and has through practice validated the methodology. Aspects of the methodology that have worked well have been maintained and other aspects that were

lacking were adjusted or refined. An example of this is contained on page 10 of Exhibit D1, Tab 2, Schedule 1, which discusses recent changes that were made to the ACA methodology in regards to Distribution Station Transformers.

c) The Acres model is an effective tool for summarizing asset conditions that are monitored using a variety of activities (e.g. targeted testing, patrol observations). To obtain a "false" reading or anomaly from the model, either i) an error occurred in the health index formulation or ii) the underlying inspections or diagnostics are not effective.

In the case of i), Hydro One Distribution would very quickly identify this result as staff typically focus more on detailed findings that make up the health index. This focus would uncover an anomaly very quickly and allow for the correction of the problem with very little consequence.

In the case of ii), the anomaly would come to the attention of staff through failure trends or contradictory data. For example, a series of failures on station transformers that had previously been deemed to be in good condition would alert staff to a problem. In response to the anomaly, staff would investigate, determine the appropriate course of action, and adjust the underlying activity (i.e. test or observation) as necessary. The consequences of the anomaly can vary from no consequence at all to unexpected equipment failure (i.e. the failures used to identify the anomaly in the first place). Once an anomaly is identified, Hydro One Distribution can take action to minimize further consequences.

d) The Acres asset analysis model is generally used to identify the health of a pole population not the specific end of life of each pole. Hydro One uses ACA information that is also used to determine the Acres Health Index for specific end of life determination. The issue with the sub-class of red pine poles was identified through ACA process and the observation of an increased failure rate of this class of poles during storms.

Ontario Energy Board (Board Staff) INTERROGATORY #109 List 1

Interrogatory

Issue 4.7 Are the proposed capital expenditures to reduce electricity system losses appropriate?

109. Ref: ExhG1/Tab 10/Sch1/p1

Hydro One indicates that losses are estimated to be higher than the values currently approved by the Board. Hydro One indicates that it is making ongoing efforts to reduce losses. What are these ongoing efforts? What capital amounts are being spent on line loss improvements? Please provide a list of programs and initiatives and their approximate costs.

Response

Hydro One reviews its system configuration routinely to ensure effective and efficient operation. Each feeder in its system is computer modeled on a six year cycle and wherever conditions such as voltage are found to be outside guidelines, remedial measures are taken. The first such measure considered is always the addition of capacitors, which offer line loss improvements as a primary benefit. Phase line current balance is also brought within target guidelines as a result of this work and losses are reduced in this way as well.

The program under which recommended improvements are implemented is titled "Distribution System Modifications". The budget for this program is $5.5M and $7.0M in 2010 & 2011, respectively. It is not possible to determine exactly what part of this expenditure is spent on line loss improvements alone as many other work items are completed as a part of these investments.

Customer power quality concerns are addressed through a program entitled "Demand Investments". If the customer issue is regarding low voltage, a capacitor will be considered for installation if it can affect a solution. The budget for this program is $1.5M in each of 2010 and 2011, but again, it is not possible to isolate expenditure on loss reduction items.

In addition to the above program work, major capital projects factor loss reduction into the various alternatives considered.

Ontario Energy Board (Board Staff) INTERROGATORY #110 List 1

Interrogatory

Issue 6.1 Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

110. Ref: ExhF1/Tab1/Sch1/p1

a) Article 2.10.1 of Chapter 2 of Filing Requirements for Transmission and Distribution Applications issued on May 27, 2009 require the Applicants to provide a continuity schedule for the period January 1, 2005 to present, showing separate itemization of opening balances, annual adjustments, accruals, interest and closing balances for deferral and variance accounts. A blank excel spreadsheet reflecting these requirements is attached. Please file the completed continuity schedule, as per the minimum filing requirements in Excel as well as PDF formats. Please include a breakout of the sub-accounts for account 1508.

b) Please provide reconciliation between the continuity schedule and amounts for regulatory assets as per the company's audited financial statements as of December 31, 2008.

c) Please list and provide a brief description of all outstanding deferral and variance accounts. Please include the deferral and variance accounts not being requested for disposition.

d) Please provide the balances of all regulatory deferral and variance accounts, including those not being requested for disposition, for the period ending December 31st, 2008. In addition, please add the forecast amounts for both principle and interest to arrive at the totals for December 31, 2009.

e) Hydro One states that all of the regulatory assets reported have been established consistent with the Board's requirements as set out in the APH. Please provide Hydro One's model for calculating variance account 1588, specifically the transactions related to calculating and booking losses in the variance account.

f) Is the balance as of December 31, 2008 for Total Regulatory Assets for Approval the same as what was reported to the Board under RRR 2.1.7 for 2008? If not, please reconcile the amounts reported under RRR to the amounts requested for disposition as of December 31, 2008.

g) Hydro One is forecasting both the principle and the interest component to December 31, 2009, for the accounts being requested for disposition? Why is it necessary to recover forecast principle balances?

Response

a) See Attachment 1

b) See Attachment 2

c)

RCVA	Represents the difference between amounts billed in relation to service transaction requests and the incremental costs associated with those activities
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.
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.
Regulatory Asset Recovery	Represents recovery of Hydro One Distribution Regulatory Assets per Board Decisions.
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
RRRP	Represents net amounts collected from IESO as a fixed charge per KWh. for rural and remote rate protection.
Deferred Pension	Represents the difference between pension contributions in the Dx Rate submission and the Dx pension contributions
Harmonization Mitigation Credit	Represents the mitigation credits that are given to approximately 1,700 Acquired customers including Residential and General Service since they are significantly impacted (ie >15%) by the new harmonized Dx rates.

d) Balance as at December 31, 2008:

RCVA	$(1.7)M
Environmental	$123.6M
Smart Meters	$2.0M
RSVA	$(20.9)M
Regulatory Asset Recovery	$(22.9)M
Cat Lake	$0.1M
RRRP	$17.3M
Deferred Pension	$0.0M
Harmonization Mitigation Credit	$0.0M

Forecast balances as at December 31, 2009 (transactions January to April 2009 and interest January to December 2009 except as noted):

RCVA	$(1.9)M
Environmental	$124.4M
Smart Meters	$2.0M
RSVA	$(2.9)M
Regulatory Asset Recovery 1	$(23.0)M
Regulatory Asset Recovery 2*	$19.7M
Regulatory Asset Recovery 3*	$(48.1)M
Regulatory Asset Recovery 4*	$18.2M
Cat Lake	$0.1M
RRRP*	$19.3M
Deferred Pension	$0.4M
Harmonization Mitigation Credit	$0.0M

* Note: Principal transactions and interest forecast to December 31, 2009.

e) Consistent with Canadian GAAP requirements, Hydro One Distribution has adopted an accrued approach for reporting monthly revenues and associated energy sales to customers. The accrued approach adopted by Hydro One Distribution provides a more accurate matching of monthly power purchases with monthly sales to customers as the methodology is independent of the effects of numerous billing cycles, infrequent meter reads, cancel/re-bill impacts and monthly bill estimates.

Accrued revenue is primarily based on IESO purchased volumes for the month; hence there is a direct match between revenue and cost for the same accounting period at the aggregate level. All volumes are consistent with the IESO monthly statement. Using the OEB-approved loss factors and historical splits, these purchases are translated into sales at the retail level which are used to calculate bill items that are based on sales such as Dx volumetric tariff and Debt Retirement Charge. For line items that must include losses such as commodity and wholesale market service charge, these same OEB-approved line loss factors are used in 'grossing up' the sales (similar to the customer's bill) to calculate total charges including losses. By first removing the OEB-approved losses, and then grossing by the same line loss factor, Hydro One is inherently assuming that we sell everything that we purchase such that there is no

difference to be accumulated in the RSVA-Power account. As this assumption is utilized, there is no recognized net income impact for any differences between what is bought and sold.

f) The amounts reported to the Board under RRR 2.1.7 for December 2008 are the same as the Total Regulatory Assets for Approval requested in this filing when individual accounts are taken into consideration. In the RRR 2.1.7 the amount for USoA 1555 includes in-service amounts of Smart Meters along with the Under-recovery amounts being requested for recovery in this filing (see reconciliation below):

In Service Amount	$154.5M
Smart Meter Under Recovery per Evidence	$0.9M
Balance per RRR2.1.7	$155.4M

As well, in the RRR 2.1.7 the amount for USoA 1590 includes amounts for Regulatory Asset Recovery not related to Phase I (RP-2004-0117/0118) which is being requested for recovery in this filing (see reconciliation below):

Regulatory Asset Recovery 1	$(18.7)M
Regulatory Asset Recovery 2	$43.3M
Regulatory Asset Recovery 3	$(72.6)M
Regulatory Asset Recovery 4	$25.0M
Balance per RRR 2.1.7	$(22.9)M

g) Hydro One Distribution is requesting disposition of actual principal balances to the end of April 2009 with interest forecast to December 31, 2009. Any differences between the approved values and actual values at year end will be tracked and trued up at the next proceeding. It is expected that new Distribution rates will be implemented at the start of January 2010.

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

Account Description	Account Number	2005 Opening Principal Amounts as of Jan-1-05 [1]	2005 Transactions (additions) during 2005, excluding interest and adjustments [6]	2005 Transactions (reductions) during 2005, excluding interest and adjustments [6]	2005 Adjustments during 2005 - instructed by Board [2]	2005 Adjustments during 2005 - other [3]	2005 Closing Principal Balance as of Dec-31-05	2005 Opening Interest Amounts as of Jan-1-05	2005 Interest Jan-1 to Dec31-05	2005 Closing Interest Amounts as of Dec-31-05	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
RSVA - Wholesale Market Services	1580	$ 500,000	$ 8,300,000		$ -	$ -	$ 8,800,000	$ -	$ 200,000	$ 200,000	$ 8,800,000	$ (35,500,000)		$ -	$ -	$ 3,200,000	$ (23,500,000)	$ 200,000
RSVA - Wholesale Market Services (Non-Recurring)	1582	$ 1,000,000	$ 1,200,000		$ -	$ -	$ 2,200,000	$ 100,000	$ 100,000	$ 200,000	$ 2,200,000	$ 200,000		$ -	$ -	$ (2,400,000)	$ -	$ 200,000
RSVA - Tx Network	1584	$ (11,300,000)	$ (10,400,000)		$ -	$ -	$ (21,700,000)	$ (500,000)	$ (1,200,000)	$ (1,700,000)	$ (21,700,000)	$ (3,400,000)		$ -	$ -	$ 30,000,000	$ 4,900,000	$ (1,700,000)
RSVA - Tx Connection	1586	$ (14,100,000)	$ (12,600,000)		$ -	$ -	$ (26,700,000)	$ (600,000)	$ (1,600,000)	$ (2,200,000)	$ (26,700,000)	$ (6,400,000)		$ -	$ -	$ 36,200,000	$ 3,100,000	$ (2,200,000)
RSVA - Provincila Benefit	1588	$ -	$ (4,900,000)		$ -	$ -	$ (4,900,000)	$ -	$ (200,000)	$ (200,000)	$ (4,900,000)	$ 12,600,000		$ -	$ -	$ -	$ 7,700,000	$ (200,000)
RSVA - LV	1550	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 800,000		$ -	$ -	$ -	$ 800,000	$ -
RSVA - TxN Aggregation	1584	$ -	$ 2,700,000		$ -	$ -	$ 2,700,000	$ -	$ -	$ -	$ 2,700,000	$ 4,100,000		$ -	$ -	$ (4,500,000)	$ 2,300,000	$ -
RSVA - TxC Aggregation	1586	$ -	$ 2,300,000		$ -	$ -	$ 2,300,000	$ -	$ -	$ -	$ 2,300,000	$ 3,500,000		$ -	$ -	$ (3,800,000)	$ 2,000,000	$ -
Sub-Totals		$ (23,900,000)	$ (13,400,000)		$ -	$ -	$ (37,300,000)	$ (1,000,000)	$ (2,700,000)	$ (3,700,000)	$ (37,300,000)	$ (24,100,000)		$ -	$ -	$ 58,700,000	$ (2,700,000)	$ (3,700,000)
RCVA	1518/1548	$ (300,000)	$ -	$ -	$ -	$ -	$ (300,000)	$ (100,000)	$ -	$ (100,000)	$ (300,000)	$ (400,000)	$ -	$ -	$ -	$ 200,000	$ (500,000)	$ (100,000)
Reg Asset Recovery Phase I	1590	$ 122,000,000	$ (40,900,000)	$ -	$ -	$ -	$ 81,100,000	$ -	$ 7,200,000	$ 7,200,000	$ 81,100,000	$ (37,100,000)	$ -	$ -	$ -	$ -	$ 44,000,000	$ 7,200,000
LV	1550	$ 25,000,000	$ 24,400,000	$ -	$ -	$ -	$ 49,400,000	$ 900,000	$ 2,800,000	$ 3,700,000	$ 49,400,000	$ 13,100,000	$ -	$ -	$ -	$ (62,500,000)	$ -	$ 3,700,000
Primary Environmental	1525	$ 24,000,000	$ (500,000)	$ -	$ -	$ -	$ 23,500,000	$ 25,600,000	$ 2,900,000	$ 28,500,000	$ 23,500,000	$ (9,700,000)	$ -	$ -	$ -	$ -	$ 13,800,000	$ 28,500,000
Dx Deferred Pension	1508	$ 33,200,000	$ 38,200,000	$ -	$ -	$ -	$ 71,400,000	$ -	$ 5,000,000	$ 5,000,000	$ 71,400,000	$ 16,300,000	$ -	$ -	$ -	$ (87,700,000)	$ -	$ 5,000,000
OEB Costs	1508	$ 1,200,000	$ 2,200,000	$ -	$ -	$ -	$ 3,400,000	$ -	$ 100,000	$ 100,000	$ 3,400,000	$ 1,000,000	$ -	$ -	$ -	$ (5,200,000)	$ (800,000)	$ 100,000
RRRP DX	1508	$ 2,400,000	$ (3,200,000)	$ -	$ -	$ -	$ (800,000)	$ (100,000)	$ 100,000	$ -	$ (800,000)	$ 1,800,000	$ -	$ -	$ -	$ -	$ 1,000,000	$ -
C&DM	1565	$ 1,000,000	$ (24,600,000)	$ -	$ -	$ -	$ (23,600,000)	$ -	$ -	$ -	$ (23,600,000)	$ 4,500,000	$ -	$ -	$ -	$ -	$ (19,100,000)	$ -
Acq MEU Rate Mitigation	1508	$ -	$ 800,000	$ -	$ -	$ -	$ 800,000	$ -	$ -	$ -	$ 800,000	$ 400,000	$ -	$ -	$ -	$ (1,200,000)	$ -	$ -
Reg Asset Recovery II	1590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (15,400,000)	$ -	$ -	$ -	$ 97,700,000	$ 82,300,000	$ -
Reg Asset Recovery III	1590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reg Asset Recovery IV	1590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reg Liabilities Tax Changes Der Account	1592	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,800,000)	$ -	$ -	$ -	$ -	$ (2,800,000)	$ -
Cat Lake (Rev,Cap,OM&A & COP + interest)	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 400,000	$ -	$ -	$ -	$ -	$ 400,000	$ -
Smart Meters Mimimum Functionality	1555/1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,000,000	$ -	$ -	$ -	$ -	$ 10,000,000	$ -
Smart Meters Exceeding Minimum Functionality	1555/1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
										$ -	$ -						$ -	$ -
							$ -			$ -	$ -						$ -	$ -
							$ -			$ -	$ -						$ -	$ -
							$ -			$ -	$ -						$ -	$ -
Sub-Totals		$ 208,500,000	$ (3,600,000)	$ -	$ -	$ -	$ 204,900,000	$ 26,300,000	$ 18,100,000	$ 44,400,000	$ 204,900,000	$ (17,900,000)	$ -	$ -	$ -	$ (58,700,000)	$ 128,300,000	$ 44,400,000
Deferred Payments in Lieu of Taxes	1562				see PILs reconciliation requested										see PILs reconciliation requested			
2006 PILs & Taxes Variance	1592				see PILs reconciliation requested										see PILs reconciliation requested			
Sub-Totals					see PILs reconciliation requested										see PILs reconciliation requested			
Total		$ 184,600,000	$ (17,000,000)	$ -	$ -	$ -	$ 167,600,000	$ 25,300,000	$ 15,400,000	$ 40,700,000	$ 167,600,000	$ (42,000,000)	$ -	$ -	$ -	$ -	$ 125,600,000	$ 40,700,000
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										see PILs reconciliation requested			
RSVA - Power (including Global Adjustment)	1588						$ -			$ -	$ -						$ -	$ -
RSVA - Power - Sub-Account - Global Adjustment [4]	1588						$ -			$ -	$ -						$ -	$ -
Recovery of Regulatory Asset Balances	1590						$ -			$ -	$ -						$ -	$ -

C:\Documents and Settings\509292\Desktop\EB-2009-0096 PDF\[H-01-110 Attachment 1.XLS]Continuity Schedule

Note (i) - Hydro One has not requested recovery of 2010 balances in this filing
Note (ii) - Hydro One has used April 2009 Actual balances and has assumed no principal transactions from May 2009 to December 2009

[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, 2008 closing principal balance.

Attachment A
Continuity Schedule

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	
NAME OF CONTACT	
E-mail Address	
VERSION NUMBER	v3.0
Date	

Account Description	Account Number	2007 Interest Jan-1 to Dec31-06	2007 Transfer of Board-approved amounts to 1590 as per 2006 EDR	2007 Closing Interest Amounts as of Dec-31-06	2007 Opening Principal Amounts as of Jan-1-07	2007 Transactions (additions) during 2007, excluding interest and adjustments [6]	2007 Transactions (reductions) during 2007, excluding interest and adjustments [6]	2007 Adjustments during 2007 - instructed by Board [2]	2007 Adjustments during 2007 - other [3]	2007 Closing Principal Balance as of Dec-31-07	2007 Opening Interest Amounts as of Jan-1-07	2008 Interest Jan-1 to Dec31-07	2008 Closing Interest Amounts as of Dec-31-07	2008 Opening Principal Amounts as of Jan-1-08	2008 Transactions (additions) during 2008, excluding interest and adjustments [6]	2008 Transactions (reductions) during 2008, excluding interest and adjustments [6]	2008 Adjustments during 2008 - instructed by Board [2]	2008 Adjustments during 2008 - other [3]
RSVA - Wholesale Market Services	1580	$ (500,000)	$ -	$ (300,000)	$ (23,500,000)	$ (36,700,000)		$ -	$ -	$ (60,200,000)	$ (300,000)	$ (1,900,000)	$ (2,200,000)	$ (60,200,000)	$ 48,900,000		$ -	$ -
RSVA - Wholesale Market Services (Non-Recurring)	1582	$ (200,000)	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
RSVA - Tx Network	1584	$ 2,000,000	$ -	$ 300,000	$ 4,900,000	$ (5,900,000)		$ -	$ -	$ (1,000,000)	$ 300,000	$ 300,000	$ 600,000	$ (1,000,000)	$ (15,700,000)		$ -	$ -
RSVA - Tx Connection	1586	$ 2,500,000	$ -	$ 300,000	$ 3,100,000	$ (2,200,000)		$ -	$ -	$ 900,000	$ 300,000	$ 100,000	$ 400,000	$ 900,000	$ (6,700,000)		$ -	$ -
RSVA - Provincila Benefit	1588	$ 400,000	$ -	$ 200,000	$ 7,700,000	$ (4,200,000)		$ -	$ -	$ 3,500,000	$ 200,000	$ 100,000	$ 300,000	$ 3,500,000	$ 2,000,000		$ -	$ -
RSVA - LV	1550	$ -	$ -	$ -	$ 800,000	$ 2,100,000		$ -	$ -	$ 2,900,000	$ -	$ 100,000	$ 100,000	$ 2,900,000	$ (1,000,000)		$ -	$ -
RSVA - TxN Aggregation	1584	$ -	$ -	$ -	$ 2,300,000	$ 4,300,000		$ -	$ -	$ 6,600,000	$ -	$ 200,000	$ 200,000	$ 6,600,000	$ (3,800,000)		$ -	$ -
RSVA - TxC Aggregation	1586	$ -	$ -	$ -	$ 2,000,000	$ 3,900,000		$ -	$ -	$ 5,900,000	$ -	$ 200,000	$ 200,000	$ 5,900,000	$ (3,000,000)		$ -	$ -
	Sub-Totals	$ 4,200,000	$ -	$ 500,000	$ (2,700,000)	$ (38,700,000)		$ -	$ -	$ (41,400,000)	$ 500,000	$ (900,000)	$ (400,000)	$ (41,400,000)	$ 20,700,000		$ -	$ -
RCVA	1518/1548	$ 100,000	$ -	$ -	$ (500,000)	$ 200,000	$ -	$ -	$ -	$ (300,000)	$ -	$ -	$ -	$ (300,000)	$ (1,300,000)	$ -	$ -	$ -
Reg Asset Recovery Phase I	1590	$ 4,100,000	$ -	$ 11,300,000	$ 44,000,000	$ (37,700,000)	$ -	$ -	$ -	$ 6,300,000	$ 11,300,000	$ 800,000	$ 12,100,000	$ 6,300,000	$ (37,000,000)	$ -	$ -	$ -
LV	1550	$ (3,700,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Primary Environmental	1525	$ 3,000,000	$ -	$ 31,500,000	$ 13,800,000	$ (6,800,000)	$ -	$ -	$ -	$ 7,000,000	$ 31,500,000	$ 2,800,000	$ 34,300,000	$ 7,000,000	$ 78,600,000	$ -	$ -	$ -
Dx Deferred Pension	1508	$ (5,000,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
OEB Costs	1508	$ (200,000)	$ -	$ (100,000)	$ (800,000)	$ 700,000	$ -	$ -	$ -	$ (100,000)	$ (100,000)	$ -	$ (100,000)	$ (100,000)	$ 100,000	$ -	$ -	$ -
RRRP DX	1508	$ -	$ -	$ -	$ 1,000,000	$ 2,700,000	$ -	$ -	$ -	$ 3,700,000	$ -	$ 100,000	$ 100,000	$ 3,700,000	$ 13,400,000	$ -	$ -	$ -
C&DM	1565	$ -	$ -	$ -	$ (19,100,000)	$ 17,800,000	$ -	$ -	$ -	$ (1,300,000)	$ -	$ -	$ -	$ (1,300,000)	$ 1,300,000	$ -	$ -	$ -
Acq MEU Rate Mitigation	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Reg Asset Recovery II	1590	$ 4,500,000	$ -	$ 4,500,000	$ 82,300,000	$ (24,500,000)	$ -	$ -	$ -	$ 57,800,000	$ 4,500,000	$ 3,300,000	$ 7,800,000	$ 57,800,000	$ (24,200,000)	$ -	$ -	$ -
Reg Asset Recovery III	1590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (70,900,000)	$ -	$ -	$ -
Reg Asset Recovery IV	1590	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,000,000	$ -	$ -	$ -
Reg Liabilities Tax Changes Der Account	1592	$ (100,000)	$ -	$ (100,000)	$ (2,800,000)	$ (3,200,000)	$ -	$ -	$ -	$ (6,000,000)	$ (100,000)	$ (100,000)	$ (200,000)	$ (6,000,000)	$ 6,000,000	$ -	$ -	$ -
Cat Lake (Rev,Cap,OM&A & COP + interest)	1508	$ -	$ -	$ -	$ 400,000	$ (100,000)	$ -	$ -	$ -	$ 300,000	$ -	$ -	$ -	$ 300,000	$ (200,000)	$ -	$ -	$ -
Smart Meters Mimimum Functionality	1555/1556	$ 200,000	$ -	$ 200,000	$ 10,000,000	$ (5,600,000)	$ -	$ -	$ -	$ 4,400,000	$ 200,000	$ 100,000	$ 300,000	$ 4,400,000	$ (3,600,000)	$ -	$ -	$ -
Smart Meters Exceeding Minimum Functionality	1555/1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,100,000	$ -	$ -	$ -
				$ -	$ -					$ -	$ -		$ -	$ -				
				$ -	$ -					$ -	$ -		$ -	$ -				
				$ -	$ -					$ -	$ -		$ -	$ -				
				$ -	$ -					$ -	$ -		$ -	$ -				
	Sub-Totals	$ 2,900,000	$ -	$ 47,300,000	$ 128,300,000	$ (56,500,000)	$ -	$ -	$ -	$ 71,800,000	$ 47,300,000	$ 7,000,000	$ 54,300,000	$ 71,800,000	$ (11,700,000)	$ -	$ -	$ -
Deferred Payments in Lieu of Taxes	1562							see PILs reconciliation requested									see PILs reconciliation reques	
2006 PILs & Taxes Variance	1592							see PILs reconciliation requested									see PILs reconciliation reques	
	Sub-Totals							see PILs reconciliation requested									see PILs reconciliation reques	
	Total	$ 7,100,000	$ -	$ 47,800,000	$ 125,600,000	$ (95,200,000)	$ -	$ -	$ -	$ 30,400,000	$ 47,800,000	$ 6,100,000	$ 53,900,000	$ 30,400,000	$ 9,000,000	$ -	$ -	$ -
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									see PILs reconciliation reques	
RSVA - Power (including Global Adjustment)	1588			$ -	$ -					$ -	$ -		$ -	$ -				
RSVA - Power - Sub-Account - Global Adjustment [4]	1588			$ -	$ -					$ -	$ -		$ -	$ -				
Recovery of Regulatory Asset Balances	1590			$ -	$ -					$ -	$ -		$ -	$ -				

Note (i) - Hydro One has not requested recovery of 2010 balances in this filing
Note (ii) - Hydro One has used April 2009 Actual balances and has assumed no principal transactions from May 2009 to December 2009

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	
NAME OF CONTACT	
E-mail Address	
VERSION NUMBER	v3.0
Date	

Account Description	Account Number	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec31-08	Closing Interest Amounts as of Dec-31-08	Projected Interest on Dec 31 -08 balance from Jan 1, 2009 to Dec 31, 2009 [9]	Note (i) Projected Interest on Dec 31 -08 balance from Jan 1, 2010 to April 30, 2010 [9]	Claim before Forecasted Transactions	Note (ii) Forecasted Transactions, Excluding Interest from Jan 1, 2009 to Dec 31, 2009	Note (i) Forecasted Transactions, Excluding Interest from Jan 1, 2010 to April 30, 2010	Note (i) Projected Interest from Jan 1, 2009 to April 30, 2010 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to December 31, 2009	Projected Interest from Jan 1, 2010 to April 30, 2010 on Forecasted Transx (Excl Interest) from Jan 1, 2010 to April 30, 2010	Total Claim	Ex F1/Tab 1/Sch 1/ Tbl 2
RSVA - Wholesale Market Services	1580	$ (11,300,000)	$ (2,200,000)	$ 2,100,000	$ (100,000)	$ (100,000)		$ (11,500,000)	$ (7,200,000)		$ -		$ (18,700,000)	
RSVA - Wholesale Market Services (Non-Recurring)	1582	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -		$ -	
RSVA - Tx Network	1584	$ (16,700,000)	$ 600,000	$ (700,000)	$ (100,000)	$ (200,000)		$ (17,000,000)	$ 6,500,000		$ -		$ (10,500,000)	
RSVA - Tx Connection	1586	$ (5,800,000)	$ 400,000	$ (400,000)	$ -	$ (100,000)		$ (5,900,000)	$ 3,400,000		$ -		$ (2,500,000)	
RSVA - Provincila Benefit	1588	$ 5,500,000	$ 300,000	$ (300,000)	$ -	$ 100,000		$ 5,600,000	$ 13,900,000		$ 100,000		$ 19,600,000	
RSVA - LV	1550	$ 1,900,000	$ 100,000	$ (100,000)	$ -	$ -		$ 1,900,000	$ 700,000		$ -		$ 2,600,000	
RSVA - TxN Aggregation	1584	$ 2,800,000	$ 200,000	$ (200,000)	$ -	$ 100,000		$ 2,900,000	$ 400,000		$ -		$ 3,300,000	
RSVA - TxC Aggregation	1586	$ 2,900,000	$ 200,000	$ (200,000)	$ -	$ -		$ 2,900,000	$ 400,000		$ -		$ 3,300,000	
	Sub-Totals	$ (20,700,000)	$ (400,000)	$ 200,000	$ (200,000)	$ (200,000)	$ -	$ (21,100,000)	$ 18,100,000	$ -	$ 100,000	$ -	$ (2,900,000)	$ (2,900,000)
RCVA	1518/1548	$ (1,600,000)	$ -	$ (100,000)	$ (100,000)	$ -		$ (1,700,000)	$ (200,000)		$ -		$ (1,900,000)	$ (1,900,000)
Reg Asset Recovery Phase I	1590	$ (30,700,000)	$ 12,100,000	$ (100,000)	$ 12,000,000	$ (300,000)		$ (19,000,000)	$ (4,000,000)		$ -		$ (23,000,000)	$ (23,000,000)
LV	1550	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -		$ -	
Primary Environmental	1525	$ 85,600,000	$ 34,300,000	$ 3,700,000	$ 38,000,000	$ 1,000,000		$ 124,600,000	$ 800,000		$ -		$ 125,400,000	
Dx Deferred Pension	1508	$ -	$ -	$ -	$ -	$ -		$ -	$ 400,000		$ -		$ 400,000	
OEB Costs	1508	$ -	$ (100,000)	$ 100,000	$ -	$ 100,000		$ 100,000	$ -		$ -		$ 100,000	
RRRP DX	1508	$ 17,100,000	$ 100,000	$ 100,000	$ 200,000	$ 200,000		$ 17,500,000	$ 2,800,000		$ -		$ 20,300,000	
C&DM	1565	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -		$ -	
Acq MEU Rate Mitigation	1508	$ -	$ -	$ -	$ -	$ -		$ -	$ -		$ -		$ -	
Reg Asset Recovery II	1590	$ 33,600,000	$ 7,800,000	$ 1,900,000	$ 9,700,000	$ 400,000		$ 43,700,000	$ (8,700,000)		$ -		$ 35,000,000	
Reg Asset Recovery III	1590	$ (70,900,000)	$ -	$ (1,700,000)	$ (1,700,000)	$ (800,000)		$ (73,400,000)	$ 6,800,000		$ -		$ (66,600,000)	
Reg Asset Recovery IV	1590	$ 25,000,000	$ -	$ -	$ -	$ 300,000		$ 25,300,000	$ 500,000		$ -		$ 25,800,000	
Reg Liabilities Tax Changes Der Account	1592	$ -	$ (200,000)	$ 200,000	$ -	$ -		$ -	$ -		$ -		$ -	
Cat Lake (Rev,Cap,OM&A & COP + interest)	1508	$ 100,000	$ -	$ -	$ -	$ -		$ 100,000	$ (100,000)		$ -		$ -	
Smart Meters Mimimum Functionality	1555/1556	$ 800,000	$ 300,000	$ (200,000)	$ 100,000	$ -		$ 900,000	$ -		$ -		$ 900,000	$ 900,000
Smart Meters Exceeding Minimum Functionality	1555/1556	$ 1,100,000	$ -	$ -	$ -	$ -		$ 1,100,000	$ -		$ -		$ 1,100,000	$ 1,100,000
		$ -	$ -		$ -			$ -					$ -	
		$ -	$ -		$ -			$ -					$ -	
		$ -	$ -		$ -			$ -					$ -	
		$ -	$ -		$ -			$ -					$ -	
	Sub-Totals	$ 60,100,000	$ 54,300,000	$ 3,900,000	$ 58,200,000	$ 900,000	$ -	$ 119,200,000	$ (1,700,000)	$ -	$ -	$ -	$ 117,500,000	$ (25,800,000)
Deferred Payments in Lieu of Taxes	1562	sted												
2006 PILs & Taxes Variance	1592	sted												
	Sub-Totals	sted						$ -					$ -	
	Total	$ 39,400,000	$ 53,900,000	$ 4,100,000	$ 58,000,000	$ 700,000	$ -	$ 98,100,000	$ 16,400,000	$ -	$ 100,000	$ -	$ 114,600,000	
The following is not included in the total claim but is included on a memo basis														
Deferred PILs Contra Account [8]	1563	sted												
RSVA - Power (including Global Adjustment)	1588	$ -	$ -		$ -			$ -					$ -	
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ -		$ -			$ -					$ -	
Recovery of Regulatory Asset Balances	1590	$ -	$ -		$ -			$ -					$ -	

C:\Documents and Settings\509292\Desktop\EB-2009-0096 PDF\[H-01-110 Attachment 1.XLS]Continuity Schedule

Note (i) - Hydro One has not requested recovery of 2010 balances in this filing
Note (ii) - Hydro One has used April 2009 Actual balances and has assumed no principal transactions from May 2009 to December 2009

Reconciliation Table

2005		($M)
Balance per OEB Continuity Schedule		
	2005 Principal	168
	2005 Interest	41
		209
Add:		
	OPEB	71
	CDM	24
Less:		
	Other	-1
Regulatory Assets & Liabilities per 2005 Dx Audited Statements		303

2006		($M)
Balance per OEB Continuity Schedule		
	2006 Principal	125
	2006 Interest	48
		173
Add:		
	OPEB	47
	CDM	19
	Other	1
Regulatory Assets & Liabilities per 2006 Dx Audited Statements		240

2007

		($M)
Balance per OEB Continuity Schedule		
	2007 Principal	30
	2007 Interest	54
		84
Add:		
	OPEB	24
	CDM	1
	Other	1
Less:		
	Reg Assets re-classified from Long Term to Short Term	-73
Regulatory Assets & Liabilities per 2007 Dx Audited Statements		37

2008

		($M)
Balance per OEB Continuity Schedule		
	2008 Principal	39
	2008 Interest	58
		97
Add:		
	Reg Liabilities re-classified from Long Term to Short Te	30
Less:		
	Reg Assets re-classified from Long Term to Short Term	-51
Regulatory Assets & Liabilities per 2008 Dx Audited Statements		76

Ontario Energy Board (Board Staff) INTERROGATORY #111 List 1

Interrogatory

Issue 6.1 Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab1/Sch1/p2

Using the information provided in the continuity schedule requested in the previous question, please provide a further schedule reconciling the continuity schedule with the amounts requested for disposition on Exhibit F1/Tab1/Schedule 1/p2.

Response

Please see Exhibit H, Tab 1, Schedule 110 Attachment 1, the last column reconciles the continuity schedule with the amounts requested for disposition in Exhibit F1, Tab 1, Schedule 1, page 2.

Ontario Energy Board (Board Staff) INTERROGATORY #112 List 1

Interrogatory

Issue 6.1 Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab1/Sch1/p1

Usual practice in the electricity sector is to use audited numbers for the last fiscal year 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, 2008 for accounts requested for disposition.

b) Please recalculate the appropriate rate rider schedules using the December 31, 2008 balances with only interest forecasted to December 31, 2009.

Response

a) The regulatory precedent can be found in EB-2007-0681, 2008 Electricity Distribution Rates. In the Hydro One Distribution submitted evidence, audited financial statements were provided up to December 31, 2007 and Regulatory Asset balances were projected to April 30, 2008. Those projected balances, with the exception of Smart Meter balances, were approved by the Board on December 18, 2008.

Another regulatory precedent can be found in 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 1 for recalculated rate rider schedule.

Determination of Rate Rider Amounts by Rate Class

RIDER # 6

		2010 statistics		UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST
2	# of Customers	1,195,542		140,540	412,455	367,107	156,901	98,776	7,361	10,577	1,130	-	-	88	607
3	GWh	36,168		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4	17,938
4	GWh excl LDC May 1, 08 to Jan 31, 09	22,777		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4	4,547
5	GWh excl WMP	23,303		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4.0	5,073
6	Billing kWs	45,542,866							10,389,644		1,898,173			66,329	33,188,720
7	2008 RARA # 1 Revenue	100%		8.03%	23.18%	25.42%	7.52%	7.52%	6.46%	0.81%	1.18%	0.18%	0.06%	0.02%	19.62%
8	**Rider # 6 Development**														
9		$ 1000s	Allocator												
10	RARA 1	$ (19,000)	2008 RARA # 1 Rev	(1,524.89)	(4,404.60)	(4,830.18)	(1,428.75)	(1,428.57)	(1,227.24)	(154.66)	(223.29)	(33.36)	(11.64)	(4.37)	(3,728.44)
11	RSVA Wholesale Mkt SrChg	$ (11,500)	GWh excl WMP	$ (646.98)	$ (2,169.91)	$ (2,652.56)	$ (354.33)	$ (1,083.72)	$ (1,540.70)	$ (179.63)	$ (296.10)	$ (60.21)	$ (10.36)	$ (1.97)	$ (2,503.52)
12	RSVA Tx Network May 1, 08 to Dec 31, 08	$ (14,100)	GWh exc LDC	$ (811.57)	$ (2,721.94)	$ (3,327.37)	$ (444.47)	$ (1,359.42)	$ (1,932.66)	$ (225.33)	$ (371.43)	$ (75.52)	$ (13.00)	$ (2.48)	$ (2,814.80)
13	RSVA Tx Connection May 1, 08 to Dec 31, 08	$ (3,000)	GWh exc LDC	$ (172.67)	$ (579.14)	$ (707.95)	$ (94.57)	$ (289.24)	$ (411.20)	$ (47.94)	$ (79.03)	$ (16.07)	$ (2.77)	$ (0.53)	$ (598.89)
14	RSVA Tx Network Feb 1, 09 to Dec 31, 09	$ -	GWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	RSVA Tx Connection Feb 1, 09 to Dec 31, 09	$ -	GWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	RSVA LV Wheeling	$ 1,900	GWh	$ 68.87	$ 230.99	$ 282.36	$ 37.72	$ 115.36	$ 164.01	$ 19.12	$ 31.52	$ 6.41	$ 1.10	$ 0.21	$ 942.33
17	RSVA Provincial Benefit	$ 5,600	GWh excl WMP	$ 315.05	$ 1,056.65	$ 1,291.68	$ 172.54	$ 527.73	$ 750.26	$ 87.47	$ 144.19	$ 29.32	$ 5.05	$ 0.96	$ 1,219.10
18	RCVA	$ (1,800)	# of Customers	$ (211.60)	$ (620.99)	$ (552.71)	$ (236.23)	$ (148.72)	$ (11.08)	$ (15.92)	$ (1.70)	$ -	$ -	$ (0.13)	$ (0.91)
19	Smart Meter Minimum Functionality to December 31, 200	$ 900	# of Customers	$ 105.80	$ 310.49	$ 276.36	$ 118.11	$ 74.36	$ 5.54	$ 7.96	$ 0.85	$ -	$ -	$ 0.07	$ 0.46
20	Smart Meter Costs Exceeding Minimum Functionality	$ 1,100	# of Customers	$ 129.31	$ 379.49	$ 337.77	$ 144.36	$ 90.88	$ 6.77	$ 9.73	$ 1.04	$ -	$ -	$ 0.08	$ 0.56
21	**Total Regulatory Assets for Approval**	$ (39,900)													
22															
23		$ (39,900.0)		$ (2,748.7)	$ (8,519.0)	$ (9,882.6)	$ (2,085.6)	$ (3,501.3)	$ (4,196.3)	$ (499.2)	$ (793.9)	$ (149.4)	$ (31.6)	$ (8.2)	$ (7,484.1)
24															
25	Assuming a 24 month recovery	$ (19,950.0)		$ (1,374.3)	$ (4,259.5)	$ (4,941.3)	$ (1,042.8)	$ (1,750.7)	$ (2,098.2)	$ (249.6)	$ (397.0)	$ (74.7)	$ (15.8)	$ (4.1)	$ (3,742.1)
26															
27															
28	Rider # 6 ¢/kWh			(0.105)	(0.097)	(0.092)	(0.145)	(0.080)	(0.067)	(0.069)	(0.066)	(0.061)	(0.075)	(0.102)	Note 1
29	$/kW								(0.20)		(0.21)			(0.06)	Note 1
30	Note 1: Rider 6a = $(0.039)/kW, Rider 6b $(0.054)/kW, Rider 6c $(0.183)/kW														

Ontario Energy Board (Board Staff) INTERROGATORY #113 List 1

Interrogatory

Issue 6.1 Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab1/Sch1/p1

Is Hydro One currently using accounts 1555 and 1556? Please identify any deviations from the Board's guidance with respect to these accounts.

Response

Hydro One Distribution is following 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).

Detailed expenditures are tracked in our Project Costing sub-ledger and summarized amounts are recorded in accounts 1555 and 1556.

Ontario Energy Board (Board Staff) INTERROGATORY #114 List 1

Interrogatory

Issue 6.1 Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab1/Sch1/p5-6

a) Please provide a detailed calculation of Smart Meter Minimum Functionality Under-recovery up to December 31, 2008 and December 31, 2009 shown in Table 4.

b) Please provide a detailed calculation of Smart Meter Exceeding Minimum Functionality Under-recovery up to December 31, 2008 and December 31, 2009 shown in Table 5.

Response

a) Below is the detailed calculation of the Under-recovery of Smart Meter Minimum Functionality up to December 31, 2008. The December 31, 2009 amount reflects the December 31st, 2008 amount shown below but interest improved using the 0.55% OEB rate. However, the impact of the 2009 interest improvement does not change the 2009 amount shown in Exhibit F1, Tab 1, Schedule 1, Table 4.

$M	2007 MF Approved	2007 MF Not Yet App	2008 MF Not Yet App	Total
OM&A	0.0	0.0	6.9	6.9
Depreciation	0.5	0.9	2.7	4.0
Capital tax	0.0	0.0	0.1	0.1
Return on debt	0.2	0.4	1.3	1.9
Return on equity	0.2	0.4	1.3	1.9
Income tax	0.1	0.1	(1.1)	(0.9)
	1.0	1.8	11.1	14.0
Interest improvement				0.1
Smart Meter Adder Recovered				(13.2)
SM Minimum Functionality Under-Recovery to Dec 31 08				0.9

b) Below is the detailed calculation of the Meter Exceeding Minimum Functionality Under-recovery up to December 31, 2008. The December 31, 2009 amount reflects the December 31st, 2008 amount shown below but interest improved using the 0.55% OEB rate. However, the impact of the 2009 interest improvement does not change the 2009 amount shown in Exhibit F1, Tab 1, Schedule 1, Table 5.

$M	2007 EF Not Yet App	2008 EF Not Yet App	Total
OM&A	0.0	0.0	0.0
Depreciation	0.1	0.5	0.7
Capital tax	0.0	0.0	0.0
Return on debt	0.1	0.3	0.3
Return on equity	0.1	0.3	0.3
Income tax	0.0	(0.2)	(0.2)
	0.2	0.9	1.1
Interest improvement			0.0
Smart Meter Adder Recovered			0.0
SM Exceeding Minimum Functionality Under-Recovery to Dec 31 08			1.1

Ontario Energy Board (Board Staff) INTERROGATORY #115 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

115. Ref: ExhF1/Tab1/Sch1/p6

Hydro One is requesting disposal of the RSVA account 1580 – Wholesale Market Services.

a) Please provide an explanation of why the balance is forecast to drop from a credit of $20.9 million in 2008 to a credit of $2.9 million in 2009.

b) Please state the amount reported to the Board for account 1580 in Hydro One's annual filing pursuant to RRR 2.1.7 for 2008.

c) Identify the components of any difference between the amount in b) above, and shown in Table 6.

d) Explain each component of the difference identified in c) above. Please include an explanation of which other accounts now contain any such difference by component.

e) State which amount (the amount in b) above or the amount in ExhF1/Tab1/Sch1) has been reflected in Hydro One's 2008 audited financial statements and identify the line item in the audited financial statements.

f) State which value should be relied upon in this proceeding, and, if different from the value reported in the 2008 audited financial statements, explain why the Board should rely on a different value.

Response

The amount provided in Exhibit F1, Tab 1, Schedule 1, page 6 represents the aggregate of all RSVA accounts which is inclusive of USofA accounts 1550, 1580, 1582, 1584, 1586 and 1588.

a) The ($2.9M) balance provided for December 2009 represents the actual balance of the various RSVA accounts as of April 2009 with interest up to December 2009. The various components of the change are as follows:

$ Million

USofA	RSVA Accounts	Dec 2008	Dec 2009	Change
1550	RSVA-LV	1.9	2.6	0.8
1580	RSVA-WMSC	(11.4)	(18.6)	(7.2)
1584	RSVA-NW	(13.9)	(7.1)	6.8
1586	RSVA-CN	(3.0)	0.7	3.7
1588	RSVA-Power (Global Adjustment)	5.5	19.4	13.9
	Total	(20.9)	(2.9)	18.0

RSVA-Power (Global Adjustment) – increased under-collection of $13.9M due to the increase in the difference between the fixed rate which is used to bill our non-RPP customers and the actual rate which is used to charge Hydro One for purchased power.

RSVA-NW and RSVA-CN – decreased over-collection of $10.5M due to the implementation of 2008 OEB-approved Distribution rates in February 2009 which reflects the decreased transmission rates.

RSVA-WMSC – decreased over-collection of $7.2M due to increased wholesale market service charges levied by the IESO. This increase brings Hydro One's costs closer in line with the fixed rate billed to customers, thus decreasing the amount of over-collection.

b) Per Hydro One's annual filing pursuant to RRR 2.1.7 for 2008, the following amounts were submitted:

$ Million

USofA	RSVA Accounts	Dec 2008
1550	RSVA-LV	1.9
1580	RSVA-WMSC	(11.4)
1584	RSVA-NW	(13.9)
1586	RSVA-CN	(3.0)
1588	RSVA-Power (Global Adjustment)	5.5
	Total	(20.9)

c) The amount provided in Exhibit F1, Tab 1, Schedule 1, page 6 is consistent with amounts submitted per the RRR 2.1.7 filing for 2008.

d) The amount provided in Exhibit F1, Tab 1, Schedule 1, page 6 is consistent with amounts submitted per the RRR 2.1.7 filing for 2008.

e) The amount provided in Exhibit F1, Tab 1, Schedule 1, page 6 is consistent with amounts submitted per the RRR 2.1.7 filing for 2008. As such, this amount was

reflected in the 2008 Distribution Financial Statements filed at Exhibit A, Tab 9, Schedule 1, Attachment 3, page 5, under Regulatory Liabilities on the Balance Sheet.

f) The amount provided in Exhibit F1, Tab 1, Schedule 1, page 6 is consistent with both the amounts submitted per the RRR 2.1.7 filing for 2008 as well as the 2008 audited financial statements.

Ontario Energy Board (Board Staff) INTERROGATORY #116 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab1/Sch6
Hydro One is proposing to refund the deferral and variance accounts to customers over a period of 2 years. Please provide a schedule identifying the rate riders associated with the disposition of the deferral and variance accounts over both one and two year periods. Please show all relevant calculations.

Response

Attachment 1 shows the calculations for the rate riders being disposed over one or two years. The riders being disposed over two years is shown in Exhibit G1, Tab 5, Schedule 1, Attachment 1. The same spreadsheet was used to calculate the one year riders, which are shown shaded at the bottom of Attachment 1.

Determination of Rate Rider Amounts by Rate Class

RIDER # 6

		2010 statistics		UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST
2	# of Customers	1,195,542		140,540	412,455	367,107	156,901	98,776	7,361	10,577	1,130	-	-	88	607
3	GWh	36,168		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4	17,938
4	GWh excl LDC May 1, 08 to Jan 31, 09	22,777		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4	4,547
5	GWh excl WMP	23,303		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4.0	5,073
6	Billing kWs	45,542,866							10,389,644		1,898,173			66,329	33,188,720
7	2008 RARA # 1 Revenue	100%		8.03%	23.18%	25.42%	7.52%	7.52%	6.46%	0.81%	1.18%	0.18%	0.06%	0.02%	19.62%
8	**Rider # 6 Development**														
9		$ 1000s	Allocator												
10	RARA 1	$ (22,975)	2008 RARA # 1 Rev	(1,843.91)	(5,326.07)	(5,840.69)	(1,727.66)	(1,727.44)	(1,483.98)	(187.02)	(270.00)	(40.34)	(14.08)	(5.28)	(4,508.46)
11	RSVA Wholesale Mkt SrChg	$ (18,710)	GWh excl WMP	$ (1,052.58)	$ (3,530.28)	$ (4,315.50)	$ (576.47)	$ (1,763.13)	$ (2,506.60)	$ (292.25)	$ (481.73)	$ (97.95)	$ (16.86)	$ (3.21)	$ (4,073.03)
12	RSVA Tx Network May 1, 08 to Jan 31, 09	$ (14,834)	GWh exc LDC	$ (853.84)	$ (2,863.71)	$ (3,500.67)	$ (467.62)	$ (1,430.23)	$ (2,033.32)	$ (237.07)	$ (390.77)	$ (79.46)	$ (13.68)	$ (2.61)	$ (2,961.41)
13	RSVA Tx Connection May 1, 08 to Jan 31, 09	$ (2,836)	GWh exc LDC	$ (163.21)	$ (547.38)	$ (669.13)	$ (89.38)	$ (273.38)	$ (388.66)	$ (45.31)	$ (74.69)	$ (15.19)	$ (2.61)	$ (0.50)	$ (566.06)
14	RSVA Tx Network Feb 1, 09 to Dec 31, 09	$ 7,657	GWh	$ 277.54	$ 930.85	$ 1,137.89	$ 152.00	$ 464.90	$ 660.93	$ 77.06	$ 127.02	$ 25.83	$ 4.45	$ 0.85	$ 3,797.49
15	RSVA Tx Connection Feb 1, 09 to Dec 31, 09	$ 3,575	GWh	$ 129.60	$ 434.66	$ 531.34	$ 70.98	$ 217.08	$ 308.62	$ 35.98	$ 59.31	$ 12.06	$ 2.08	$ 0.40	$ 1,773.24
16	RSVA LV Wheeling	$ 2,660	GWh	$ 96.40	$ 323.33	$ 395.25	$ 52.80	$ 161.48	$ 229.57	$ 26.77	$ 44.12	$ 8.97	$ 1.54	$ 0.29	$ 1,319.06
17	RSVA Provincial Benefit	$ 19,571	GWh excl WMP	$ 1,101.07	$ 3,692.90	$ 4,514.30	$ 603.03	$ 1,844.35	$ 2,622.07	$ 305.71	$ 503.92	$ 102.46	$ 17.64	$ 3.36	$ 4,260.66
18	RCVA	$ (1,959)	# of Customers	$ (230.27)	$ (675.79)	$ (601.49)	$ (257.08)	$ (161.84)	$ (12.06)	$ (17.33)	$ (1.85)	$ -	$ -	$ (0.14)	$ (0.99)
19	Smart Meter Minimum Functionality to December 31, 200	$ 877	# of Customers	$ 103.07	$ 302.49	$ 269.23	$ 115.07	$ 72.44	$ 5.40	$ 7.76	$ 0.83	$ -	$ -	$ 0.06	$ 0.45
20	Smart Meter Costs Exceeding Minimum Functionality	$ 1,141	# of Customers	$ 134.12	$ 393.62	$ 350.35	$ 149.74	$ 94.27	$ 7.02	$ 10.09	$ 1.08	$ -	$ -	$ 0.08	$ 0.58
21	**Total Regulatory Assets for Approval**	$ (25,832)													
22															
23		$ (25,832.3)		$ (2,302.0)	$ (6,865.4)	$ (7,729.1)	$ (1,974.6)	$ (2,501.5)	$ (2,591.0)	$ (315.6)	$ (482.8)	$ (83.6)	$ (21.5)	$ (6.7)	$ (958.5)
24															
25	Assuming a 24 month recovery	$ (12,916.2)		$ (1,151.0)	$ (3,432.7)	$ (3,864.6)	$ (987.3)	$ (1,250.8)	$ (1,295.5)	$ (157.8)	$ (241.4)	$ (41.8)	$ (10.8)	$ (3.3)	$ (479.2)
26															
27															
28	Rider # 6 ¢/kWh			(0.088)	(0.078)	(0.072)	(0.138)	(0.057)	(0.041)	(0.043)	(0.040)	(0.034)	(0.051)	(0.084)	Note 1
29	$/kW								(0.12)		(0.13)			(0.05)	Note 1

30 Note 1: Rider 6a = $0.034/kW, Rider 6b $0.008/kW, Rider 6c $(0.189)/kW

Rider # 6 assuming one year recovery

	Rider # 6 ¢/kWh			(0.176)	(0.156)	(0.144)	(0.275)	(0.114)	(0.083)	(0.087)	(0.080)	(0.069)	(0.102)	(0.167)	Note 2
	$/kW								(0.25)		(0.25)			(0.10)	Note 2

Note 2: Rider 6a = $0.068/kW, Rider 6b $0.016/kW, Rider 6c $(0.378)/kW

Ontario Energy Board (Board Staff) INTERROGATORY #117 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab3/Sch1

Hydro One is requesting a new deferral and variance account for the Pension Cost Differential. The Board's Decision with Reasons EB-2007-0681 (page 48), dated December 18, 2008 approved such an account for Hydro One.

a) Is the account being proposed in addition to the one approved in EB-2007-0681 for recording Pension Cost Differential?
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 are not known, what is the basis of the approval to record these amounts in a deferral account?
f) Is there new or additional information since the July 13, 2009 filing of this application that would assist the Board on this request?

Response

Note: There is no Exhibit F1, Tab 3, Schedule 1, we believe the correct reference should be Exhibit F1, Tab 1, Schedule 2.

a) This account is not in addition to the one approved in EB-2007-0681, it is an extension of that account.

b) 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. The next actuarial valuation is required as at December 31, 2009, and will be filed with FSCO in September 2010. 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.

Hydro One Distribution is requesting an extension of the Pension Cost Differential, given the account in EB-2007-0681 was specifically approved to record the difference between the pension costs included in 2008 rates and actual pension costs.

The account requested in this current filing will track the difference between the pension costs included in 2010 and 2011 rates and actual costs for those years.

c) Hydro One would use Account 1508 Other Regulatory Assets; Sub Account Pension Contributions.

d) 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.

e) Pension costs in this application are estimated based on the December 31, 2006 valuation report, consistent with EB-2007-0681. As noted above, the deferral account will capture the difference between these estimates and the actual costs derived from the valuation to be determined as of December 31, 2009.

f) There is no new or additional information.

Ontario Energy Board (Board Staff) INTERROGATORY #118 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

118. Ref: ExhF1/Tab3/Sch1

Hydro One is requesting a new deferral and variance account related to the OEB Cost Differential.

a) Is this the same account that was proposed by Hydro One in EB-2007-0681, which was subsequently rejected by the Board in its Decision with Reasons dated December 18, 2008 (page 49), stating: "The Board does not consider it reasonable in this case to exempt Hydro One from the Board's current policy not to authorize an OEB cost variance account to distributors"?

b) If it is not the same account that was proposed in EB-2007-0681, then what is the regulatory precedent for the collection of each of the identified costs proposed to be included in this deferral account?

c) What is the justification for this account?

d) What account number does Hydro One propose to use in the USoA?

e) What are the journal entries to be recorded?

f) If the costs are not known, what is the basis of the approval to record these amounts in a deferral account?

g) Is there new or additional information since the July 13, 2009 filing of this application that would assist the Board on this request?

Response

There is no exhibit F1, Tab 3, Schedule 1, we believe the correct reference should be Exhibit F1, Tab 1, Schedule 2.

a) This account is similar in nature to the one that was proposed by Hydro One in EB-2007-0681.

b) Subsequent to the above noted Distribution decision, the Board Decision in EB-2008-0272 Section 8.2 Disposition and Continuation of Existing Accounts, the Board finding on page 56.

c) The deferral account, if approved, as described in Exhibit F1, Tab 1, Schedule 2, page 1, lines 23 to 26 would track the difference between the annual OEB Cost Assessments, intervenor cost awards and cost associated with OEB initiated studies and the amount for these expenditures approved by the OEB as part of this proceeding.

d) Hydro One would use Account 1508 Other Regulatory Assets; Sub Account OEB Costs.

e) Where OEB costs recovered through rates are lower than actual OEB costs incurred, the entry will be:

Dr. OEB Costs Deferral Account (asset)
Cr. Revenue

Where OEB costs recovered are higher than actual OEB costs incurred, the opposite entry would apply.

f) The costs of these are currently unknown. When actual costs are known the deferral account will capture the difference between the actual annual OEB Cost Assessments, intervenor cost awards and cost associated with OEB initiated studies and the amount for these expenditures approved by the OEB as part of this proceeding.

g) There is no new or additional information.

Ontario Energy Board (Board Staff) INTERROGATORY #119 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab3/Sch1

Hydro One is requesting a new deferral and variance account related to the Impact of Change in IFRS. The Board report EB-2008-0408 dated July 28, 2009 "Transition to International Financial Reporting Standards" (Appendix 2, article 8.2) states:

> "The Board will establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS. This account …….. is not to include …… impacts on revenue requirements arising from changes in the timing of the recognition of expenses."

a) Does Hydro One Distribution currently have any IFRS related costs approved in rates? If so,
   i) Are variances between the approved costs and actual costs of transitioning to IFRS being recorded in a variance account?
   ii) Please provide reference of when such variance account was approved.
   iii) What is the current balance in this variance account?

b) Is the proposed account expected to record any costs specifically excluded in the Board report EB-2008-0408 (i.e. ongoing compliance costs or impacts on revenue requirement arising from changes in timing of the recognition of expenses)?

Response

There is no Exhibit F1, Tab 3, Schedule 1. Hydro One believes the correct reference for this Interrogatory should be Exhibit F1, Tab 1, Schedule 2.

a) Yes, Hydro One Distribution currently has IFRS transition-related costs included in approved rates.

   i) Hydro One is not tracking variances between approved transition costs and actual costs of transition in a variance account.

ii) N/A.

iii) N/A.

b) The proposed variance account is not intended to record transition costs, rather, it is being proposed to record the difference between costs in the current revenue requirement and any difference in revenue requirement resulting from changes in the application of IFRS standards once they are approved.

Ontario Energy Board (Board Staff) INTERROGATORY #120 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab3/Sch1

Hydro One is requesting a new deferral and variance account related to the Fixed Charge for Micro-Generators.

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 are not known, what is the basis of the approval to record these amounts in a deferral account?

f) Is there new or additional information since the July 13, 2009 filing of this application that would assist the Board on this request?

Response

Note: There is no Exhibit F1, Tab 3, Schedule 2, we believe the correct reference should be Exhibit F1, Tab 1, Schedule 2 and have responded based on this exhibit.

a) b) The deferral account, if approved, as described in Exhibit F1, Tab 1, Schedule 2, page 2, lines 9 to 11 would record the revenues collected from the application of this new charge. The proposed 2010 and 2011 Revenue Requirement does not include any potential revenues collected from this new charge. Tracking this amount in a variance account ensures that customers will derive the benefit of any additional revenues collected by this new charge, once the variance account is cleared in the future.

c) Hydro One would use Account 1508 Other Regulatory Assets; Sub Account Fixed Charge for Micro-Generators.

d) The entry will be:
Dr. Revenue
Cr. Fixed Charge for Micro-Generators (deferral account)

e) The revenue to be received for Micro-Generators fixed meter charge is unknown. As noted above the deferral account will capture this revenue in a variance account to be refunded in the future to customers. The revenue is not included in as a reduction in our revenue requirement.

f) The Board has initiated a Proceeding, EB-2009-0326, to determine how to establish a fixed charge for micro-generators.

Ontario Energy Board (Board Staff) INTERROGATORY #121 List 1

Interrogatory

Issue 6.2 Are the proposed new Deferral and Variance Accounts appropriate?

Ref: ExhF1/Tab3/Sch1

Hydro One is requesting a new deferral and variance account for the Bill Impact Mitigation. The Board approved such an account in its December 18, 2008 Decision with Reasons EB-2007-0681 (page 50), stating:

> "The Board authorizes Hydro One to establish the proposed mitigation account to record the costs of harmonization, including the incremental costs reasonably incurred for implementation".

a) How is the new account being proposed different from the one already approved by the Board in EB-2007-0681?
b) What account number does Hydro One propose to use in the USoA?
c) What are the journal entries to be recorded?
d) If the costs are not known, what is the basis of the approval to record these amounts in a deferral account?
e) Is there new or additional information since the July 13, 2009 filing of this application that would assist the Board on this request?

Response

Note: There is no Exhibit F1, Tab 3, Schedule 2, we believe the correct reference should be Exhibit F1, Tab 1, Schedule 2 and have responded based on this exhibit.

a) This account would track a different bill impact mitigation, if required, than the bill impact mitigation approved in the EB-2007-0681 Proceeding.

b) Hydro One would use Account 1508 Other Regulatory Assets; Sub Account Bill Impact Mitigation.

c) The journal entries are:
Dr. Bill Impact Mitigation (deferral account)
Cr. Revenue.

d) The costs would be known once the revenue requirement is approved by the OEB and before the rates would be implemented.

e) No

Ontario Energy Board (Board Staff) INTERROGATORY #122 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG2/Tab1/Sch1/p2

To enable a better understanding of Density Weighting Factors, please provide an example (or a small number of examples) of an actual feeder that is used to serve customers in several classes, showing how factors such as the length of the feeder, the number of customers, and the energy supplied are used to create Density Weighting Factors.

Response

To illustrate the Density Weighting Factors, three feeders have been randomly selected. Connectivity Data provides information on customer connections by rate class to each of the feeders. The length of the feeders is known. Based on the share of customers per rate class, a portion of the feeder is allocated to each rate class. This process is conducted on over 3000 feeders to determine the total allocated kms per rate class.

The km/customer metric is based on the total allocated feeder kms per rate class. The density factors are determined by weighing the km/cut by total customers as outlined in the example below.

Similar steps are repeated using energy share per rate class to allocate the portion of feeders to each rate class and derive the km/demand metric.

Connectivity Data

			Rate Class							
	Feeder	Km	Dgen	GSd	GSe	R1	R2	Seasonal	Unmtr	Total
	ABERDEEN DS F1	175	1	1	78	16	706	87	2	891
	ABERDEEN DS F2	41			22	3	257	18	1	301
	ABERDEEN DS F3	24		1	25	12	234	7	1	280
A	**Totals**	**240**	**1**	**2**	**125**	**31**	**1,197**	**112**	**4**	**1,472**

Allocated KM

			Rate Class						
	Feeder	Km	Dgen	GSd	GSe	R1	R2	Seasonal	Unmtr
	ABERDEEN DS F1	175	0.2	0.2	15.3	3.1	138.3	17.0	0.4
	ABERDEEN DS F2	41	-	-	3.0	0.4	35.3	2.5	0.1
	ABERDEEN DS F3	24	-	0.1	2.1	1.0	20.1	0.6	0.1
B	**Totals**	**240**	**0.2**	**0.3**	**20.4**	**4.6**	**193.6**	**20.1**	**0.6**
C = B / A	km/ cust		0.20	0.14	0.16	0.15	0.16	0.18	0.15
D	Wts		1.20*	0.86	1.00	0.91	0.99	1.10	0.94
E = DxA	Check	1,472	1.2	1.7	125.5	28.1	1,188.3	123.4	3.8

D* = WTs 0.20x1472/ [(0.20*1)+ (0.14*2)+ (0.16*125) + (0.15*31)+ (0.16*1197)+ (0.18*112)+ (0.15*4)] =1.20

1

Ontario Energy Board (Board Staff) INTERROGATORY #123 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1/p24

The report submitted by Hydro One states that "HOD currently has very limited information …" on differences amongst a list of some seven factors in urban and rural areas. Considering this statement, how does Hydro One plan to improve its information on cost differences that would address the Board's concerns expressed in the 2008 Decision?

Response

Hydro One Networks does not plan to improve its information on cost differences at this time but believes a staged approach to addressing the Board direction is a reasonable way to proceed that avoids making disruptive, and possibly unnecessary, changes to the current rate design. The staged approach was supported by the majority of Stakeholders. Please see the attached letter to Ms. Kirsten Walli, "EB-2009-0096 – Hydro One Networks' 2010 and 2011 Distribution Application – Hydro One Network's Density Study", dated April 20, 2009.

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Susan Frank
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BY COURIER

April 20, 2009

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

Dear Ms. Walli:

EB-2009-0096 – Hydro One Networks' 2010 and 2011 Distribution Rate Application – Hydro One Networks' Density Study

In a letter to the Board dated February 11, 2009 Hydro One Networks Inc. ("Hydro One") advised the Ontario Energy Board (the "Board") of its intent to file a cost of service Application for 2010 and 2011 electricity distribution rates (EB-2009-0096).

As part of the preparations for its current Application, on April 15, 2009 Hydro One held a stakeholder session to discuss the Board's direction in their Decision on Hydro One's last Distribution Application (EB-2007-0681). The Board directed Hydro One to develop a benchmarking approach that will provide definitive information respecting Hydro One's relative efficiency in the vegetation management area of operations, as well as to provide a more detailed analysis on the relationship between density and cost allocation.

Ten stakeholders attended the April 15th session and provided valuable feedback to assist Hydro One in shaping the evidence for its current Application. With respect to assessing the relationship between density and cost allocation, the majority of stakeholders felt Hydro One should proceed first with establishing the principles that could guide the definition of density based rate classes and establishing the factors that drive the relationship between density and cost allocation. The participant from FOCA suggested Hydro One simply maintain the status quo approach to density given all the current issues that will impact customers' rates, while the participant from SEC felt Hydro One should proceed immediately to carry out a detailed evaluation of how costs vary in response to customer density.

Hydro One believes the view expressed by the majority of stakeholders is the prudent course of action at this time. Until such time as the guiding principles and density cost drivers are established, it is inappropriate to proceed to detailed analysis.

Hydro One noted during this session its concern with making changes to the current rate classes and cost allocation methodology at this time, given the following:

- Hydro One is still in the middle of the 4 year Harmonization plan approved by the Board in its last Decision
- The increasing pressure on rates driven by work related to the Smart Network and Distributed Generation connections (Green Energy and Green Economy Act)
- Direction provided in the OEB staff discussion paper entitled "Rate Classification for Electricity Distribution Customers" on eliminating density-related customer classification

Therefore, Hydro One believes a staged approach to addressing the Board direction is a reasonable way to proceed that avoids making disruptive, and possibly unnecessary, changes to the current rate design.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

c: Mr. Jay Shepherd, School Energy Coalition (SEC)
Mr. Wayne Clark, Association of Major Power Consumers of Ontario (AMPCO)
Mr. Bill Harper, Vulnerable Energy Consumers Coalition (VECC)
Mr. David MacIntosh, Energy Probe
Mr. Peter Faye, Energy Probe
Mr. John McGee, Federation of Ontario Cottagers' Associations (FOCA)
Ms. Judy Kwik, Power Workers' Union (PWU)
Mr. John T. Armstrong, Rogers Cable
Mr. Colin McLorg, Toronto Hydro
Mr. Harold Thiessen, Ontario Energy Board (OEB)

Ontario Energy Board (Board Staff) INTERROGATORY #124 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

124. Ref: ExhG2/Tab2/Sch5/p2

The 2008 EB-2007-0681 Decision included a four-year rate harmonization plan, which corresponds to a four year period between cost of service applications. Hydro One has filed a cost of service application after two years, and with it, has filed a report that is described as "developing the principles that should be considered in establishing the relationship between Density and cost causality".

Does Hydro One plan to provide a detailed quantitative analysis of the cost of serving customers with areas with differing customer density within two years, i.e. within the four year period that is more usual between cost of service applications?

Response

Hydro One would like to obtain the intervenors and Board's views on the principles outlined in the consultant's report and if it is decided to proceed with the analysis, Hydro One would like Board's direction on which alternative should be employed to try to find a relationship between density factors and costs. It should be kept in mind that undertaking any study will require significant effort and costs to be incurred by Hydro One. As the consultant's report's mentions in its summary in Exhibit G1, Tab 2, Schedule 5, Attachment 1, section 5.3, page 23, the benefit of any study undertaken is unclear.

At this time Hydro One can not state if such a study, if required to be performed, can be completed in the next two years.

Ontario Energy Board (Board Staff) INTERROGATORY #125 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: EB-2007-0681, Transcript 5, page 24, line 7 to page 25, line 25

Hydro One witness, Mr. Roger, testified in 2008 that a connectivity study of Hydro One's customers was ongoing at that time. (The context of the testimony was not density criteria, but rather a density review designed to assign customers to classes within the existing criteria.)

a) If Hydro One were to use engineering analysis or analysis of sample data in its response to the Board's request for an analysis of cost differences, would the analysis be dependent on completion of the connectivity study?

b) Has the connectivity study been completed?

Response

a) No, the engineering analysis would not be dependent on completion of the GIS system referred to by Mr. Roger in the transcript referenced but it would be of assistance in identifying asset location.

b) The connectivity study has not yet been done. It was decided to wait for when better customer connectivity and lines details are available in our GIS system. This has not yet been completed.

Ontario Energy Board (Board Staff) INTERROGATORY #126 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG2/Tab2/Sch5

The Board's Decision EB-2007-0681 reads, in part, at p. 30:

> "The Board remains concerned that there may be factors that make it less costly to serve the Acquired Distributor territories than Legacy systems but this conclusion cannot be reached on the basis of the cost allocation information provided by Hydro One. The Board agrees with the intervenors that Hydro One has not established that there are no significant differences in serving residential customers of Acquired Distributors compared to the Legacy customers."

What is the average number of customers per km of line in Acquired distributors whose customers are classified as R1? What is the average number of customers per km of line in areas of the province where Legacy customers are predominantly classified as R1, as distinct from UR and R2?

If data required to answer the previous interrogatory are not available, will it become available with progress toward an upgraded customer connectivity database, as described for example in the EB-2007-0681 transcript (Volume 5, page 24, line 7 to page 25, line 25)?

Response

The average number of customers per km of line for Acquired distributors was calculated using 2008 customer count and the kilometers of line information provided when the LDC was purchased by Hydro One.

To determine the average number of customers per km of line for areas where Legacy customers are predominantly classified as R1, only those feeders were selected where more than 50% of customers connected are R1 legacy customers. Analysis was conducted using customer statistics and connectivity data from 2008.

The average number of customers per km of line for Acquired distributors is 37.02 customers per kilometer. In comparison, the average number of customers per km of line in areas where Legacy customers are predominately classified as R1 is 31.04. The table below shows the average numbers of customers per km of line for Acquired areas versus those areas where majority of the customers are R1 legacy customers.

	Legacy	Acquired
Min number of customers per kilometer	0.26	10.56
Max number of customers per kilometer	460.00	91.95
Average number of customers per kilometer	31.04	37.02

Ontario Energy Board (Board Staff) INTERROGATORY #127 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1

At page 22, the report submitted by Hydro One suggests as one methodology "Sample Data", i.e. analysis of a small number of typical feeders serving the classes in question. At p. 24, it lists five factors related to customer density that might cause lower density areas to have higher costs.

a) Did Hydro One consider providing an analysis of "sample data" in response to the Board's expressed concerns – in particular did it consider using sample data to analyze the first three factors storm damage, brushing, and travel time? If not, why not?

b) If Hydro One has done any such analysis, please provide the status of any progress in the sample data analysis.

Response

a) Hydro One did not consider providing an analysis of "sample data". As explained in Exhibit H, Tab 1, Schedule 123, Hydro One and most Stakeholders agreed to develop first the principles, before any study would be undertaken.

b) No such study has been done by Hydro One.

Ontario Energy Board (Board Staff) INTERROGATORY #128 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1

At page 23, the report lists "Engineering Analysis" as an approach that "could serve as either a cross-check on Hydro One Distribution's existing weighting factors, or it could be used to derive new allocation factors". At page 24, it lists five factors related to customer density that might cause lower density areas to have higher costs.

a) Did Hydro One consider providing an engineering analysis in response to the Board's expressed concerns – in particular did it consider using engineering analysis for the fourth and fifth factors which are standardized distribution stations and customers per unit of line? If not, why not?

b) If Hydro One has done any such engineering analysis, please provide the status of the analysis.

Response

a) Please see response to Exhibit H, Tab 1, Schedule 123.

b) No study has been undertaken.

Ontario Energy Board (Board Staff) INTERROGATORY #129 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

129. Ref: ExhG1-2-5/Attachment 1

At page 24, the report lists two factors that could cause areas with high density to have higher costs: congestion in commercial areas, and underground facilities. Please explain how the two factors would have relevance to customers in Hydro One's R1 class, or alternatively please confirm that these factors have little relevance to the Board's expressed concerns.

Response

The two factors listed may not directly have relevance to Hydro One's R1 customer class, but the factors have relevance for Urban type customer classifications. Indirectly the factors have relevance to the R1 class as the density definition used to differentiate urban type customers from non-urban type customers would be affected by the two factors mentioned on page 24.

Ontario Energy Board (Board Staff) INTERROGATORY #130 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1

The Board's Decision EB-2007-0681 reads, in part, at page 31:

> "the Board directs Hydro One to provide a more detailed analysis on the relationship between density and cost allocation to the Board. This should consider **whether the number of Residential and General Service customer classes in the new class structure is adequate …."** (emphasis added)

The report submitted by Hydro One appears to make no reference to the number of classes.

a) Please confirm that the scope of the analysis is limited to the existing approved number of classes and does not consider alternatives such as splitting one class (eg R1) into two classes, or dividing two classes (eg UR and R1) into three classes.

b) If confirmed, does Hydro One intend to provide an analysis in the future, and if so when?

Response

a) Hydro One does not agree that the Board's direction limits Hydro One to existing approved classes. Hydro One interprets the word "adequate" to mean that the number of classes can increase or decrease as a result of any study undertaken to establish the relationship between density and costs.

b) Please see response to part a)

Ontario Energy Board (Board Staff) INTERROGATORY #131 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1

The Board's Decision EB-2007-0681 reads, in part, at page 31:

> "Comparisons with the costs of distributors similar in size and location to Acquired Distributors would also be useful. ……the Board expects Hydro One to provide **comparative analysis to allow the Board to better assess cost differences between the Legacy and Acquired customers**. " (emphasis added)

The report submitted by Hydro One appears to contain no comparison such as described by the Board.

a) Please provide the results of the comparison if such a comparison was made.

b) If no comparison was made by Hydro One, please explain why not.

Response

a) and b) No comparison was made. Please see response to Exhibit I, Tab 1, Schedule 123.

The Acquired LDCs have only one element in common and that is that they were purchased by Hydro One. As can be seen in applying the current Urban density criteria, only 11 of the 88 Acquired LDCs meet the Urban density criteria, so there are no common characteristics that would be applicable to all Acquired LDCs. After the four year harmonization plan is completed there will no longer be any differentiation between Acquired and Legacy customers.

Ontario Energy Board (Board Staff) INTERROGATORY #132 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1/ Executive Summary p2

The report submitted lists three issues that "are linked to the urban rural definitions": RRRP, Service Quality Indicators, and Feasibility Test (DCF Model). Please confirm that none of these factors would have precluded or complicated a quantitative analysis that would address the Board's expressed concerns for cost differences between the Legacy customers and Acquired distributor customers in the existing approved classes.

Response

The quantitative analysis would not be affected by the three issues listed, but any change to Urban class definition would impact the three issues listed. For example, for Service Quality Indicator (SQI) purposes, feeders are defined as Urban or non-urban using a 60 customers/kilometer criteria. Any change to this Urban criteria that may result from undertaking the Board directed study in finding a relationship between density and costs, may result in feeder definition being changed and, therefore, it's SQI.

Ontario Energy Board (Board Staff) INTERROGATORY #133 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1/p2

Given that the Board's expressed concern is with the classification of the customers of Acquired distributors, and none of these customers (except for a small number in Caledon) are eligible for RRRP, please confirm that consideration of RRRP is outside the scope of Hydro One's analysis of density-related cost allocation, and that it should not cause a delay in such an analysis.

Response

Consideration of RRRP is outside the scope of the analysis of density-related cost allocation, but the point raised in this exhibit is that any change resulting from a review of density criteria study may have implications for RRRP.

Hydro One understands that the Board's concern also relates to the density definition criteria used for Urban, R1, and R2 customer classes. Any change to the density definition criteria resulting from undertaking the Board's directed study may results in more or less customers being classified as Urban, R1, and R2 and therefore the amount of RRRP provided to R2 customers would potentially change. Some Acquired LDC customers could end up being classified as R2 customers.

Ontario Energy Board (Board Staff) INTERROGATORY #134 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Ref: ExhG1-2-5/Attachment 1/p20

The report lists four alternative approaches for developing cost allocation proportions to customer classes. The stated purpose is to produce a more precise allocation amongst classes.

Please confirm that Hydro One was aware of all of these methodologies prior to receiving this report, and that it could have implemented any or all of them without waiting for the report that it has filed.

Response

Yes, Hydro One was aware of the four alternative approaches but could not have implemented any or all of them as the necessary data is not readily available. Please refer to Exhibit H, Tab 1, Schedule 123, for further explanation.

Ontario Energy Board (Board Staff) INTERROGATORY #135 List 1

Interrogatory

Issue 7.2 Are the proposed revenue to cost ratios for each class appropriate?

Ref: ExhG2/Tab1/Sch1/p6

External Revenues of $40.6 million are reclassified from USoA 4330 to USoA 5135.

a) Please describe these two accounts and how each is allocated to the customer classes, and explain why the transfer is desirable.

b) Please confirm that the corresponding transfer in 2008 was $5.85 million, and describe why External Revenue has changed to such an extent over the brief interval.

Response

a) The External Revenue of $40.6 million in USoA 4330 is related to the revenues forecasted for contestable work activities relating to DGen class. The transfer is required as USoA 4330 is not picked up in the corresponding OM&A calculations in the cost allocation model, the $40.6 million has been reclassified to USoA 5135 "Overhead Distribution Lines and Feeders - Right of Way".

USoA 4330 is allocated to customers based on Net Fixed Assets. USoA 5135 is based on a joint demand and customer allocator USoA 1830 & USoA 1835.

b) Yes, the corresponding transfer of External Revenue in 2008 was $5.85 million. On September 25, 2009 Hydro One provided an update to the pre-filed evidence to reflect the proposed Distribution System Code amendments issued by the Board on September 11, 2009, which reduced the value for External Revenues by $36.0 million resulting in a revised value requiring reclassification of $4.4 million.

Ontario Energy Board (Board Staff) INTERROGATORY #136 List 1

Interrogatory

Issue 7.2 Are the proposed revenue to cost ratios for each class appropriate?

Ref: ExhG2/Tab1/Sch1/p7

Sub-accounts have been created to "provide a split between LV and other end-use customers". In light of new terminology, is the referred to split between embedded distributors versus other Sub-Transmission customers, or between ST customers versus customers in other classes, or some other split?

Response

The referred split is between ST customers versus customers in other classes.

Ontario Energy Board (Board Staff) INTERROGATORY #137 List 1

Interrogatory

Issue 7.2 Are the proposed revenue to cost ratios for each class appropriate?

Ref: ExhG2/Tab1/Sch1/Attachement1/pp. 35-36
The revenue to cost ratio for Sentinel Lighting is 0.408 if External Revenue is allocated with CWNB (the number of weighted bills) and is 0.666 if External Revenue is allocated with Hydro One's "unique" allocation.

a) Please confirm that Hydro One regards the unique allocation as preferable and has used it as the status quo ratio in its rebalancing proposal.

b) Please provide a brief explanation of the Sentinel Light revenue component in the "unique" allocation of External Revenue.

c) Distribution Revenue is $1,626,040, and Miscellaneous Revenue allocated by CWNB is $129,491. In EB-2007-0681, Exhibit H/Tab1/Sch1 Hydro One provided the information that the Sentinel Light revenue of approximately $4,000,000 was included in Miscellaneous Revenue. What is the corresponding amount in this application?

Response

a) Yes, Hydro One does regard the "unique" allocation as preferable and has used it as the status quo ratio in its rebalancing proposal.

b) Hydro One Distribution includes sentinel lighting as a regulated activity by virtue of Regulation 116/02 dated March 22, 2002, which allows Hydro One Distribution to include in its regulated rate base the assets and OM&A directly related to the provision of sentinel light services. The sentinel light rental program is designed to provide rural customers with low-cost security lighting.

In the allocation of External Revenue, over $3,300,000 is directly allocated to Sentinel Light rate class as a credit to recover the metering and other costs associated with providing this service. The remaining components of External Revenue are proportionately distributed to all rate classes as determined by the allocators.

c) The corresponding amount in this application is $3.3 million.

Ontario Energy Board (Board Staff) INTERROGATORY #138 List 1

Interrogatory

Issue 7.2 Are the proposed revenue to cost ratios for each class appropriate?

Ref: ExhG2/Tab1/Sch1/p8-19 and EB-2007-0681Decision, p. 32

The following table shows in column 1 the revenue to cost ratios resulting from the cost allocation study submitted in EB-2007-0681 and the then-existing rates. In column 2 the table shows the ratios that were proposed and approved by the Board, based on fully harmonized rates. It shows in column 3 the revenue to cost ratios that result from, in the numerator the currently existing revenues, and in the denominator, the cost allocation study filed with this application.

Revenue to Cost Ratios				
	col. 1	col.2	col.3	col. 4
Class	**2008 Ratios**	**Approved Ratios**	**Status Quo Ratios**	**Target Range**
UR	0.87	1.0	1.09	0.85 – 1.15
R1	0.82	0.88	0.92	0.85 – 1.15
R2	1.04	1.04	1.02	0.85 – 1.15
Seasonal	0.92	1.0	1.16	
UGSe	1.29	1.2	1.21	0.8 – 1.2
UGSd	0.95	1.0	1.25	0.8 – 1.8
GSe	1.08	1.08	1.07	0.8 – 1.2
GSd	1.02	1.02	0.88	0.8 – 1.8
ST	2.35	1.15	1.01	0.85 – 1.15
DG	1.63	1.0	1.35	
Streetlights	0.60	0.7	0.68	0.7 – 1.2
Sentinel Lights	0.62	0.7	0.67	0.7 – 1.2

a) Please confirm that the information presented in the table is correct, and if not please provide corrections.

b) Please provide an explanation of why the ratios in column 3 differ from those in column 2. Please make particular reference to those classes whose ratios have moved from less than 1.0 to above 1.0: UR, Seasonal, and UGSd, and the class whose ratio has moved from above 1.0 to below 1.0: GSd.

c) Does Hydro One intend to re-balance its rates in 2010 to bring any revenue to cost ratios in column 3 closer to 1.0?

Response

a) The information presented in the table is correct.

b) The ratios in column 3 (Proposed Revenue to Cost Ratios 2010) differ to those in column 2 (Approved Cost Ratios 2008) as a result of the changes in the load forecast and density weights in these two years. This impacts the underlying allocators and the distribution of cost and revenue between the classes. Specific changes in rates are given below:

UR	Ratio has increased due to a decrease in density weights and load forecast.
Seasonal	Density weights have been set to one in the current model. This reduction has increased the revenue to cost ratio.
UGd	Density weights and load forecast have declined for this group.
GSd	Load forecast has increased for GSd customers resulting in the customers attracting more costs.

c) No. Hydro One has re-balanced the 2010 rates to bring the revenue to cost ratios within the target range as provided by the Board guidelines, shown in column 4. For example, Seasonal class revenue to cost ratio has been re-balanced from 1.16 to 1.15. Please refer to Exhibit G1, Tab 3, Schedule 1, pages 4 and 5 for further details.

Ontario Energy Board (Board Staff) INTERROGATORY #139 List 1

Interrogatory

Issue 7.4 Are the proposed rate impact mitigation plans appropriate and are the resulting customer bill impacts reasonable?

139. Ref: ExhG2/Tab1/Sch1/p3–4

Residential customers are classified as Urban in 11 Acquired distributors, and General Service customers in 10 Acquired distributors.

a) Please confirm that the number of Acquired distributors was 12 Residential and 11 General Service in Hydro One's 2008 Application (same Exhibit references).

b) Please provide a list of the Acquired distributors whose customers may be classified as Urban, and compare it to the list provided in 2008 (EB-2007-0681/ExhibitG2/Tab3/Schedule1/p3), and explain why Acquired distributor(s) have apparently been dropped from the list.

c) Have customers been reclassified from UR to R1 in the distributor(s) listed in the response to part b? If so please provide impact calculations showing how customers of various sizes would be affected.

d) If applicable, please repeat part c) for General Service customers.

Response

a) Yes, the number of Acquired Distributors was 12 Residential and 11 General Service in Hydro One's 2008 Application.

b) The following Acquired distributor customers have been classified as Urban:

Arnprior
Brockville
Caledon (0H 01)
Carleton Place
Lindsay
Owen Sound (GBE)
Perth
Smith Falls
Stouffville (Whitchurch Stouffville)
Thorold
Trenton (Quinte West)

c) In the list provided in 2008 (EB-2007-0681/ExhibitG2/Tab3/Schedule1/p3), which was based on the Urban density study conducted in the summer of 2007 Dryden was also included. Since then, the Urban density study was updated in the summer of 2008 prior to implementing the approved 2008 Distribution rates and Dryden customers no longer meet the requirement to be classified as Urban.

d) Yes, customers from the 11 Acquired Distributors referred in section b) have been re-classified from UR to R1 effective June 1, 2009. Total bill impacts to Acquired customers that stayed in the UR path and that have been moved to the R1 path are illustrated in the attached table for customers with varying energy usage levels. The impacts reflect the increase implemented June 1, 2009 based on 3rd Generation Incentive Regulation Mechanism and the second step of the 4 year harmonization plan.

e) Yes, customers from 10 Acquired Distributors in section b) have been re-classified from UGe to GSe and from UGd to GSd effective June 1, 2009. Total bill impacts to Acquired customers that have stayed in the Urban path and have been moved to the GSe or GSd path are illustrated in the attached table for customers with varying electricity usage. The impacts reflect the increase implemented June 1, 2009 based on 3rd Generation Incentive Regulation Mechanism and the second step of the 4 year harmonization plan.

Total Bill Impacts of Proposed Distribution Rates:

Classes	Scenario	2008 Incl Rate Riders								2009 + IRM Incl Rate Riders										Non-Dx Compoent								600.0 Commodity Bands							
		Existing Dx Rates							Existing Dx	New Dx Rates								New Dx																
			SrChg	Rider4	base	Rider2	Rider3	Rider4	VarChg	[$/month]	SrChg	Rider4	base	Rider2	Rider3	Rider4	Rider 5AB	VarChg	[$/month]	RTSR old	RTSR new	WMSC old	WMSC new	DRC	TLF new	Old	New	Band 1 5.7	Band 2 6.6	Old	New	Existing Total Bill	New Total Bill	Incr Total Bill	Incr Total Bill
New Cla	Old Class	kWh	[$/cust]	[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		c/kWh	c/kWh	c/kWh	c/kWh	c/kWh		$	$	kWhs	kWhs	Total $	Total $	[$/month]	[$/month]	[$/month]	%
UR	Arnprior	100	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	15.75	13.91	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	17.25	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	24.25	25.87	1.61	6.6%
		250	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	19.44	13.91	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	21.05	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	40.70	42.58	1.88	4.6%
		500	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	25.59	13.91	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	27.38	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	68.11	70.44	2.33	3.4%
		750	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	31.74	13.91	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	33.71	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	97.40	100.18	2.77	2.8%
		1,000	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	37.89	13.91	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	40.03	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	127.24	130.46	3.22	2.5%
		1,500	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	50.19	13.91	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	52.69	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	186.91	191.03	4.12	2.2%
		2,000	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	62.49	13.91	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	65.34	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	246.59	251.60	5.01	2.0%
UR	Brockville	100	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	16.47	14.52	0.81	2.32	0.16	-0.11	0.13	0.05	2.54	17.88	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	24.97	26.49	1.52	6.1%
		250	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	20.04	14.52	0.81	2.32	0.16	-0.11	0.13	0.05	2.54	21.69	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	41.30	43.23	1.92	4.7%
		500	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	25.99	14.52	0.81	2.32	0.16	-0.11	0.13	0.05	2.54	28.06	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	68.51	71.12	2.61	3.8%
		750	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	31.94	14.52	0.81	2.32	0.16	-0.11	0.13	0.05	2.54	34.42	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	97.60	100.89	3.29	3.4%
		1,000	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	37.89	14.52	0.81	2.32	0.16	-0.11	0.13	0.05	2.54	40.78	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	127.24	131.21	3.97	3.1%
		1,500	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	49.79	14.52	0.81	2.32	0.16	-0.11	0.13	0.05	2.54	53.50	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	186.51	191.84	5.33	2.9%
		2,000	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	61.69	14.52	0.81	2.32	0.16	-0.11	0.13	0.05	2.54	66.22	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	245.79	252.48	6.69	2.7%
UR	Caledon OH 01	100	17.74	0.80	1.95	0.16	-0.11	0.13	2.13	20.67	17.46	0.82	2.44	0.16	-0.11	0.13	0.045	2.67	20.94	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	29.17	29.56	0.38	1.3%
		250	17.74	0.80	1.95	0.16	-0.11	0.13	2.13	23.87	17.46	0.82	2.44	0.16	-0.11	0.13	0.05	2.67	24.94	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	45.13	46.47	1.35	3.0%
		500	17.74	0.80	1.95	0.16	-0.11	0.13	2.13	29.19	17.46	0.82	2.44	0.16	-0.11	0.13	0.05	2.67	31.61	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	71.71	74.67	2.96	4.1%
		750	17.74	0.80	1.95	0.16	-0.11	0.13	2.13	34.52	17.46	0.82	2.44	0.16	-0.11	0.13	0.05	2.67	38.27	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	100.18	104.74	4.57	4.6%
		1,000	17.74	0.80	1.95	0.16	-0.11	0.13	2.13	39.84	17.46	0.82	2.44	0.16	-0.11	0.13	0.05	2.67	44.94	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	129.19	135.36	6.17	4.8%
		1,500	17.74	0.80	1.95	0.16	-0.11	0.13	2.13	50.49	17.46	0.82	2.44	0.16	-0.11	0.13	0.05	2.67	58.27	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	187.21	196.61	9.39	5.0%
		2,000	17.74	0.80	1.95	0.16	-0.11	0.13	2.13	61.14	17.46	0.82	2.44	0.16	-0.11	0.13	0.05	2.67	71.60	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	245.24	257.85	12.61	5.1%
UR	Carleton Place	100	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	18.06	15.61	0.81	2.28	0.15	-0.11	0.13	0.05	2.50	18.93	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	26.56	27.54	0.97	3.7%
		250	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	21.71	15.61	0.81	2.28	0.15	-0.11	0.13	0.05	2.50	22.68	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	42.97	44.21	1.24	2.9%
		500	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	27.78	15.61	0.81	2.28	0.15	-0.11	0.13	0.05	2.50	28.93	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	70.30	71.99	1.69	2.4%
		750	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	33.86	15.61	0.81	2.28	0.15	-0.11	0.13	0.05	2.50	35.18	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	99.52	101.65	2.14	2.1%
		1,000	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	39.93	15.61	0.81	2.28	0.15	-0.11	0.13	0.05	2.50	41.44	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	129.28	131.86	2.58	2.0%
		1,500	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	52.08	15.61	0.81	2.28	0.15	-0.11	0.13	0.05	2.50	53.94	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	188.80	192.28	3.48	1.8%
		2,000	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	64.23	15.61	0.81	2.28	0.15	-0.11	0.13	0.05	2.50	66.45	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	248.33	252.70	4.37	1.8%
UR	GBE	100	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	14.00	12.83	0.81	2.40	0.13	-0.11	0.13	0.05	2.60	16.24	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	22.50	24.85	2.35	10.4%
		250	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	17.38	12.83	0.81	2.40	0.13	-0.11	0.13	0.05	2.60	20.13	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	38.64	41.66	3.03	7.8%
		500	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	23.00	12.83	0.81	2.40	0.13	-0.11	0.13	0.05	2.60	26.62	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	65.52	69.68	4.16	6.3%
		750	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	28.63	12.83	0.81	2.40	0.13	-0.11	0.13	0.05	2.60	33.11	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	94.29	99.58	5.29	5.6%
		1,000	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	34.25	12.83	0.81	2.40	0.13	-0.11	0.13	0.05	2.60	39.60	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	123.60	130.02	6.42	5.2%
		1,500	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	45.50	12.83	0.81	2.40	0.13	-0.11	0.13	0.05	2.60	52.57	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	182.22	190.92	8.69	4.8%
		2,000	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	56.75	12.83	0.81	2.40	0.13	-0.11	0.13	0.05	2.60	65.55	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	240.85	251.81	10.96	4.5%
UR	Lindsay	100	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	18.64	15.79	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	19.10	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	27.14	27.71	0.56	2.1%
		250	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	22.27	15.79	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	22.83	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	43.53	44.36	0.83	1.9%
		500	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	28.32	15.79	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	29.06	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	70.84	72.12	1.28	1.8%
		750	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	34.37	15.79	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	35.29	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	100.03	101.76	1.73	1.7%
		1,000	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	40.42	15.79	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	41.52	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	129.77	131.94	2.17	1.7%
		1,500	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	52.52	15.79	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	53.97	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	189.24	192.31	3.07	1.6%
		2,000	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	64.62	15.79	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	66.43	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	248.72	252.68	3.96	1.6%
UR	Perth	100	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	18.02	15.46	0.81	2.28	0.18	-0.11	0.13	0.045	2.53	18.81	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	26.52	27.42	0.89	3.4%
		250	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	21.71	15.46	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	22.60	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	42.97	44.13	1.16	2.7%
		500	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	27.86	15.46	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	28.93	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	70.38	71.99	1.61	2.3%
		750	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	34.01	15.46	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	35.26	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	99.67	101.73	2.06	2.1%
		1,000	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	40.16	15.46	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	41.59	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	129.51	132.01	2.50	1.9%
		1,500	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	52.46	15.46	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	54.24	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	189.18	192.58	3.40	1.8%
		2,000	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	64.76	15.46	0.81	2.28	0.18	-0.11	0.13	0.05	2.53	66.90	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	248.86	253.15	4.29	1.7%
UR	Quinte West	100	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	11.56	11.36	0.81	2.43	0.11	-0.11	0.13	0.05	2.61	14.78	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	20.06	23.39	3.32	16.6%
		250	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	14.61	11.36	0.81	2.43	0.11	-0.11	0.13	0.05	2.61	18.69	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	35.87	40.22	4.35	12.1%
		500	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	19.68	11.36	0.81	2.43	0.11	-0.11	0.13	0.05	2.61	25.20	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	62.20	68.26	6.06	9.7%
		750	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	24.76	11.36	0.81	2.43	0.11	-0.11	0.13	0.05	2.61	31.71	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	90.42	98.18	7.77	8.6%
		1,000	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	29.83	11.36	0.81	2.43	0.11	-0.11	0.13	0.05	2.61	38.23	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	119.18	128.66	9.48	8.0%
		1,500	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	39.98	11.36	0.81	2.43	0.11	-0.11	0.13	0.05	2.61	51.26	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	176.70	189.60	12.90	7.3%
		2,000	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	50.13	11.36	0.81	2.43	0.11	-0.11	0.13	0.05	2.61	64.29	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	234.23	250.54	16.31	7.0%
UR	Smiths Falls	100	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	16.47	14.37	0.81	2.28	0.17	-0.11	0.13	0.045	2.52	17.70	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	24.97	26.32	1.34	5.4%
		250	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	20.15	14.37	0.81	2.28	0.17	-0.11	0.13	0.05	2.52	21.49	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	41.41	43.02	1.61	3.9%
		500	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	26.27	14.37	0.81	2.28	0.17	-0.11	0.13	0.05	2.52	27.79	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	68.79	70.85	2.06	3.0%
		750	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	32.40	14.37	0.81	2.28	0.17	-0.11	0.13	0.05	2.52	34.09	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	98.06	100.56	2.50	2.6%
		1,000	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	38.52	14.37	0.81	2.28	0.17	-0.11	0.13	0.05	2.52	40.39	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	127.87	130.82	2.95	2.3%
		1,500	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	50.77	14.37	0.81	2.28	0.17	-0.11	0.13	0.05	2.52	53.00	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	187.49	191.34	3.85	2.1%
		2,000	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	63.02	14.37	0.81	2.28	0.17	-0.11	0.13	0.05	2.52	65.60	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	247.12	251.86	4.74	1.9%
UR	Thorold	100	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	17.17	14.85	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	18.16	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	25.67	26.77	1.09	4.3%
		250	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	20.80	14.85	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	21.89	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	42.06	43.42	1.36	3.2%
		500	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	26.85	14.85	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	28.12	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	69.37	71.18	1.81	2.6%
		750	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	32.90	14.85	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	34.35	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	98.56	100.82	2.26	2.3%
		1,000	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	38.95	14.85	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	40.57	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	128.30	131.00	2.70	2.1%
		1,500	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	51.05	14.85	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	53.03	0.92	0.99	0.62	0.65	0.70	1.08	35.40	37.02	600	900	101.32	101.32	187.77	191.37	3.60	1.9%
		2,000	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	63.15	14.85	0.81	2.28	0.14	-0.11	0.13	0.05	2.49	65.49	0.92	0.99	0.62	0.65	0.70	1.08	47.20	49.36	600	1,400	136.90	136.90	247.25	251.74	4.49	1.8%
UR	Whitchurch Stouffville	100	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	14.78	13.41	0.81	2.37	0.12	-0.11	0.13	0.045	2.56	16.78	0.92	0.99	0.62	0.65	0.70	1.08	2.36	2.47	100	-	6.14	6.14	23.28	25.39	2.11	9.0%
		250	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	18.14	13.41	0.81	2.37	0.12	-0.11	0.13	0.05	2.56	20.61	0.92	0.99	0.62	0.65	0.70	1.08	5.90	6.17	250	-	15.36	15.36	39.40	42.14	2.74	7.0%
		500	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	23.74	13.41	0.81	2.37	0.12	-0.11	0.13	0.05	2.56	27.00	0.92	0.99	0.62	0.65	0.70	1.08	11.80	12.34	500	-	30.72	30.72	66.26	70.06	3.80	5.7%
		750	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	29.34	13.41	0.81	2.37	0.12	-0.11	0.13	0.05	2.56	33.39	0.92	0.99	0.62	0.65	0.70	1.08	17.70	18.51	600	150	47.96	47.96	95.00	99.86	4.85	5.1%
		1,000	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	34.94	13.41	0.81	2.37	0.12	-0.11	0.13	0.05	2.56	39.77	0.92	0.99	0.62	0.65	0.70	1.08	23.60	24.68	600	400	65.75	65.75	124.29	130.20	5.91	4.8%
		1,500

Total Bill Impacts of Proposed Distribution Rates:

Classes		Scenario				2008 Incl Rate Riders					2009 + IRM Incl Rate Riders									Non-Dx Compoent						Other Re	Other Reg	Commodity Bands				Existing	New	Incr	Incr
		Existing Dx Rates								Existing Dx	New Dx Rates								New Dx	RTSR old		RTSR new		WMSC old	WMSC new	DRC	TLF old	Old	New	Band 1 5.7	Band 2 6.6	Old	New	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	Rider4 [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	Rider4 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	Rider4 [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	Rider4 [c/kWh]	Rider 5AB [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh		c/kWh		c/kWh		c/kWh		$	$	kWhs	kWhs	Total $	Total $	[$/month]	[$/month]	[$/month]	%
R1	Arnprior	100	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	15.75	15.06	0.79	2.78	0.18	-0.12	0.11	0.05	3.01	18.86	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	24.27	27.55	3.28	13.5%
		250	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	19.44	15.06	0.79	2.78	0.18	-0.12	0.11	0.05	3.01	23.38	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	40.73	45.09	4.36	10.7%
		500	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	25.59	15.06	0.79	2.78	0.18	-0.12	0.11	0.05	3.01	30.90	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	68.17	74.32	6.16	9.0%
		750	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	31.74	15.06	0.79	2.78	0.18	-0.12	0.11	0.05	3.01	38.42	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	97.48	105.48	8.00	8.2%
		1,000	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	37.89	15.06	0.79	2.78	0.18	-0.12	0.11	0.05	3.01	45.94	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	127.35	137.16	9.81	7.7%
		1,500	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	50.19	15.06	0.79	2.78	0.18	-0.12	0.11	0.05	3.01	60.98	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	187.08	200.51	13.44	7.2%
		2,000	12.49	0.80	2.26	0.18	-0.11	0.13	2.46	62.49	15.06	0.79	2.78	0.18	-0.12	0.11	0.05	3.01	76.02	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	246.80	263.86	17.06	6.9%
R1	Brockville	100	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	16.47	15.67	0.79	2.78	0.16	-0.12	0.11	0.05	2.99	19.45	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	24.99	28.14	3.15	12.6%
		250	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	20.04	15.67	0.79	2.78	0.16	-0.12	0.11	0.05	2.99	23.94	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	41.33	45.65	4.32	10.5%
		500	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	25.99	15.67	0.79	2.78	0.16	-0.12	0.11	0.05	2.99	31.41	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	68.57	74.83	6.27	9.1%
		750	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	31.94	15.67	0.79	2.78	0.16	-0.12	0.11	0.05	2.99	38.88	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	97.68	105.94	8.26	8.5%
		1,000	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	37.89	15.67	0.79	2.78	0.16	-0.12	0.11	0.05	2.99	46.35	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	127.35	137.57	10.22	8.0%
		1,500	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	49.79	15.67	0.79	2.78	0.16	-0.12	0.11	0.05	2.99	61.29	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	186.68	200.82	14.15	7.6%
		2,000	13.29	0.80	2.20	0.16	-0.11	0.13	2.38	61.69	15.67	0.79	2.78	0.16	-0.12	0.11	0.05	2.99	76.23	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	246.00	264.07	18.07	7.3%
R1	Caledon CH 02	100	16.71	0.78	2.00	0.08	-0.12	0.11	2.07	19.56	18.41	0.80	2.88	0.08	-0.12	0.11	0.05	3.01	22.22	0.93	1.01	0.62	0.65	0.70	1.09	2.38	2.50	100	-	6.18	6.18	28.13	30.90	2.78	9.9%
		250	16.71	0.78	2.00	0.08	-0.12	0.11	2.07	22.67	18.41	0.80	2.88	0.08	-0.12	0.11	0.05	3.01	26.73	0.93	1.01	0.62	0.65	0.70	1.09	5.95	6.25	250	-	15.46	15.46	44.08	48.45	4.37	9.9%
		500	16.71	0.78	2.00	0.08	-0.12	0.11	2.07	27.84	18.41	0.80	2.88	0.08	-0.12	0.11	0.05	3.01	34.26	0.93	1.01	0.62	0.65	0.70	1.09	11.91	12.51	500	-	30.92	30.92	70.67	77.68	7.01	9.9%
		750	16.71	0.78	2.00	0.08	-0.12	0.11	2.07	33.02	18.41	0.80	2.88	0.08	-0.12	0.11	0.05	3.01	41.78	0.93	1.01	0.62	0.65	0.70	1.09	17.86	18.76	600	150	48.31	48.31	99.19	108.85	9.66	9.7%
		1,000	16.71	0.78	2.00	0.08	-0.12	0.11	2.07	38.19	18.41	0.80	2.88	0.08	-0.12	0.11	0.05	3.01	49.30	0.93	1.01	0.62	0.65	0.70	1.09	23.82	25.01	600	400	66.21	66.21	128.22	140.53	12.31	9.6%
		1,500	16.71	0.78	2.00	0.08	-0.12	0.11	2.07	48.54	18.41	0.80	2.88	0.08	-0.12	0.11	0.05	3.01	64.35	0.93	1.01	0.62	0.65	0.70	1.09	35.73	37.52	600	900	102.02	102.02	186.28	203.88	17.60	9.4%
		2,000	16.71	0.78	2.00	0.08	-0.12	0.11	2.07	58.89	18.41	0.80	2.88	0.08	-0.12	0.11	0.05	3.01	79.40	0.93	1.01	0.62	0.65	0.70	1.09	47.64	50.02	600	1,400	137.82	137.82	244.35	267.24	22.90	9.4%
R1	Carleton Place	100	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	18.06	16.77	0.80	2.78	0.15	-0.12	0.11	0.05	2.98	20.54	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	26.58	29.23	2.65	10.0%
		250	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	21.71	16.77	0.80	2.78	0.15	-0.12	0.11	0.05	2.98	25.01	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	42.99	46.73	3.73	8.7%
		500	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	27.78	16.77	0.80	2.78	0.15	-0.12	0.11	0.05	2.98	32.46	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	70.36	75.89	5.53	7.9%
		750	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	33.86	16.77	0.80	2.78	0.15	-0.12	0.11	0.05	2.98	39.90	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	99.60	106.97	7.37	7.4%
		1,000	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	39.93	16.77	0.80	2.78	0.15	-0.12	0.11	0.05	2.98	47.35	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	129.39	138.57	9.18	7.1%
		1,500	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	52.08	16.77	0.80	2.78	0.15	-0.12	0.11	0.05	2.98	62.24	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	188.97	201.77	12.81	6.8%
		2,000	14.83	0.80	2.26	0.15	-0.11	0.13	2.43	64.23	16.77	0.80	2.78	0.15	-0.12	0.11	0.05	2.98	77.13	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	248.54	264.98	16.43	6.6%
R1	GBE	100	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	14.00	13.97	0.79	2.78	0.13	-0.12	0.11	0.05	2.96	17.72	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	22.52	26.41	3.89	17.3%
		250	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	17.38	13.97	0.79	2.78	0.13	-0.12	0.11	0.05	2.96	22.16	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	38.66	43.87	5.21	13.5%
		500	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	23.00	13.97	0.79	2.78	0.13	-0.12	0.11	0.05	2.96	29.56	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	65.58	72.98	7.41	11.3%
		750	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	28.63	13.97	0.79	2.78	0.13	-0.12	0.11	0.05	2.96	36.95	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	94.37	104.02	9.65	10.2%
		1,000	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	34.25	13.97	0.79	2.78	0.13	-0.12	0.11	0.05	2.96	44.35	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	123.71	135.57	11.86	9.6%
		1,500	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	45.50	13.97	0.79	2.78	0.13	-0.12	0.11	0.05	2.96	59.14	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	182.39	198.67	16.29	8.9%
		2,000	10.95	0.80	2.10	0.13	-0.11	0.13	2.25	56.75	13.97	0.79	2.78	0.13	-0.12	0.11	0.05	2.96	73.93	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	241.06	261.77	20.71	8.6%
R1	Lindsay	100	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	18.64	16.95	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	20.71	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	27.16	29.40	2.24	8.3%
		250	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	22.27	16.95	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	25.17	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	43.56	46.88	3.32	7.6%
		500	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	28.32	16.95	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	32.59	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	70.90	76.02	5.12	7.2%
		750	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	34.37	16.95	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	40.01	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	100.11	107.07	6.96	7.0%
		1,000	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	40.42	16.95	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	47.43	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	129.88	138.65	8.77	6.8%
		1,500	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	52.52	16.95	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	62.27	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	189.41	201.80	12.40	6.5%
		2,000	15.42	0.80	2.26	0.14	-0.11	0.13	2.42	64.62	16.95	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	77.11	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	248.93	264.96	16.02	6.4%
R1	Perth	100	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	18.02	16.61	0.80	2.78	0.18	-0.12	0.11	0.05	3.01	20.41	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	26.54	29.10	2.56	9.7%
		250	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	21.71	16.61	0.80	2.78	0.18	-0.12	0.11	0.05	3.01	24.93	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	43.00	46.64	3.64	8.5%
		500	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	27.86	16.61	0.80	2.78	0.18	-0.12	0.11	0.05	3.01	32.45	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	70.44	75.88	5.44	7.7%
		750	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	34.01	16.61	0.80	2.78	0.18	-0.12	0.11	0.05	3.01	39.97	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	99.75	107.03	7.28	7.3%
		1,000	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	40.16	16.61	0.80	2.78	0.18	-0.12	0.11	0.05	3.01	47.49	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	129.62	138.71	9.09	7.0%
		1,500	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	52.46	16.61	0.80	2.78	0.18	-0.12	0.11	0.05	3.01	62.53	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	189.35	202.06	12.72	6.7%
		2,000	14.76	0.80	2.26	0.18	-0.11	0.13	2.46	64.76	16.61	0.80	2.78	0.18	-0.12	0.11	0.05	3.01	77.57	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	249.07	265.42	16.34	6.6%
R1	Quinte West	100	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	11.56	12.51	0.79	2.45	0.11	-0.12	0.11	0.05	2.61	15.91	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	20.08	24.59	4.52	22.5%
		250	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	14.61	12.51	0.79	2.45	0.11	-0.12	0.11	0.05	2.61	19.82	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	35.89	41.53	5.64	15.7%
		500	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	19.68	12.51	0.79	2.45	0.11	-0.12	0.11	0.05	2.61	26.33	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	62.26	69.76	7.50	12.0%
		750	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	24.76	12.51	0.79	2.45	0.11	-0.12	0.11	0.05	2.61	32.84	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	90.50	99.91	9.41	10.4%
		1,000	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	29.83	12.51	0.79	2.45	0.11	-0.12	0.11	0.05	2.61	39.36	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	119.29	130.58	11.29	9.5%
		1,500	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	39.98	12.51	0.79	2.45	0.11	-0.12	0.11	0.05	2.61	52.39	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	176.87	191.92	15.05	8.5%
		2,000	8.73	0.80	1.90	0.11	-0.11	0.13	2.03	50.13	12.51	0.79	2.45	0.11	-0.12	0.11	0.05	2.61	65.41	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	234.44	253.26	18.81	8.0%
R1	Smiths Falls	100	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	16.47	15.52	0.79	2.78	0.17	-0.12	0.11	0.05	3.00	19.31	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	24.99	28.00	3.01	12.1%
		250	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	20.15	15.52	0.79	2.78	0.17	-0.12	0.11	0.05	3.00	23.81	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	41.43	45.52	4.09	9.9%
		500	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	26.27	15.52	0.79	2.78	0.17	-0.12	0.11	0.05	3.00	31.31	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	68.85	74.73	5.89	8.6%
		750	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	32.40	15.52	0.79	2.78	0.17	-0.12	0.11	0.05	3.00	38.80	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	98.14	105.87	7.73	7.9%
		1,000	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	38.52	15.52	0.79	2.78	0.17	-0.12	0.11	0.05	3.00	46.30	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	127.98	137.52	9.54	7.5%
		1,500	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	50.77	15.52	0.79	2.78	0.17	-0.12	0.11	0.05	3.00	61.29	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	187.66	200.82	13.17	7.0%
		2,000	13.22	0.80	2.26	0.17	-0.11	0.13	2.45	63.02	15.52	0.79	2.78	0.17	-0.12	0.11	0.05	3.00	76.28	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	247.33	264.12	16.79	6.8%
R1	Thorold	100	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	17.17	16.00	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	19.76	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	25.69	28.45	2.76	10.8%
		250	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	20.80	16.00	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	24.22	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	42.09	45.93	3.84	9.1%
		500	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	26.85	16.00	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	31.64	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	69.43	75.07	5.64	8.1%
		750	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	32.90	16.00	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	39.06	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	98.64	106.12	7.48	7.6%
		1,000	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	38.95	16.00	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	46.48	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	128.41	137.70	9.29	7.2%
		1,500	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	51.05	16.00	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	61.32	0.93	1.01	0.62	0.65	0.70	1.08	35.56	37.52	600	900	101.32	102.02	187.94	200.85	12.92	6.9%
		2,000	13.95	0.80	2.26	0.14	-0.11	0.13	2.42	63.15	16.00	0.80	2.78	0.14	-0.12	0.11	0.05	2.97	76.16	0.93	1.01	0.62	0.65	0.70	1.08	47.42	50.02	600	1,400	136.90	137.82	247.46	264.01	16.54	6.7%
R1	Whitchurch Stouffville	100	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	14.78	14.55	0.79	2.78	0.12	-0.12	0.11	0.05	2.95	18.29	0.93	1.01	0.62	0.65	0.70	1.08	2.37	2.50	100	-	6.14	6.18	23.30	26.98	3.68	15.8%
		250	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	18.14	14.55	0.79	2.78	0.12	-0.12	0.11	0.05	2.95	22.71	0.93	1.01	0.62	0.65	0.70	1.08	5.93	6.25	250	-	15.36	15.46	39.43	44.43	5.00	12.7%
		500	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	23.74	14.55	0.79	2.78	0.12	-0.12	0.11	0.05	2.95	30.09	0.93	1.01	0.62	0.65	0.70	1.08	11.85	12.51	500	-	30.72	30.92	66.32	73.51	7.20	10.9%
		750	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	29.34	14.55	0.79	2.78	0.12	-0.12	0.11	0.05	2.95	37.46	0.93	1.01	0.62	0.65	0.70	1.08	17.78	18.76	600	150	47.96	48.31	95.08	104.52	9.44	9.9%
		1,000	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	34.94	14.55	0.79	2.78	0.12	-0.12	0.11	0.05	2.95	44.83	0.93	1.01	0.62	0.65	0.70	1.08	23.71	25.01	600	400	65.75	66.21	124.40	136.05	11.65	9.4%
		1,500	11.74	0.80	2.10	0.12	-0.11	0.13	2.24	46.14	14.55	0.79	2.78	0.12	-0.12	0.11	0.05	2.95

Total Bill Impacts of Proposed Distribution Rates:

Classes		Scenario	2008 Incl Rate Riders							2009 + IRM Incl Rate Riders								Non-Dx Compoent						Other Reg Charges		750.0 Commodity Bands				Existing	New	Incr	Incr
			Existing Dx Rates						Existing Dx	New Dx Rates							New Dx	RTSR old	RTSR n	WMSC old	WMSC new	DRC	TLF old	Old	New	Band 1 5.7	Band 2 6.6	Old	New	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg [$/cust]	Rider4 [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	Rider4 [c/kWh]	VarChg [c/kWh]	[$/month]	SrChg [$/cust]	Rider4 [$/cust]	base [c/kWh]	Rider2 [c/kWh]	Rider3 [c/kWh]	Rider4 [c/kWh]	Rider 5A [c/kWh]	VarChg [c/kWh]	[$/month]	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh		$	$	kWhs	kWhs	Total $	Total $	[$/month]	[$/month]	[$/month]	%
UGe	Arnprior	1,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	37.33	18.08	(0.203)	1.97	0.06	(0.13)	(0.038)	0.034	1.90	36.87	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	123.96	124.37	0.41	0.3%
		2,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	55.33	18.08	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	55.86	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	235.33	237.61	2.28	1.0%
		5,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	109.33	18.08	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	112.83	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	569.47	577.34	7.87	1.4%
		10,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	199.33	18.08	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	207.79	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1126.35	1143.55	17.19	1.5%
		15,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	289.33	18.08	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	302.74	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1683.24	1709.75	26.52	1.6%
UGe	Brockville	1,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	37.06	17.95	(0.203)	1.97	0.04	(0.13)	(0.038)	0.034	1.88	36.54	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	123.69	124.04	0.35	0.3%
		2,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	54.86	17.95	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	55.33	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	234.86	237.08	2.22	0.9%
		5,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	108.26	17.95	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	111.70	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	568.40	576.21	7.81	1.4%
		10,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	197.26	17.95	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	205.66	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1124.28	1141.42	17.13	1.5%
		15,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	286.26	17.95	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	299.61	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1680.17	1706.62	26.46	1.6%
UGe	Carleton Place	1,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	38.86	18.96	(0.202)	1.97	0.07	(0.13)	(0.038)	0.034	1.91	37.85	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	125.49	125.35	(0.14)	-0.1%
		2,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	56.96	18.96	(0.20)	1.97	0.07	(0.13)	(0.04)	0.034	1.91	56.94	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	236.96	238.69	1.73	0.7%
		5,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	111.26	18.96	(0.20)	1.97	0.07	(0.13)	(0.04)	0.034	1.91	114.21	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	571.40	578.72	7.32	1.3%
		10,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	201.76	18.96	(0.20)	1.97	0.07	(0.13)	(0.04)	0.034	1.91	209.67	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1128.78	1145.43	16.64	1.5%
		15,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	292.26	18.96	(0.20)	1.97	0.07	(0.13)	(0.04)	0.034	1.91	305.12	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1686.17	1712.14	25.97	1.5%
UGe	GBE	1,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	28.98	12.32	(0.209)	1.97	0.06	(0.13)	(0.038)	0.034	1.90	31.10	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	115.61	118.60	3.00	2.6%
		2,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	46.98	12.32	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	50.09	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	226.98	231.84	4.86	2.1%
		5,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	100.98	12.32	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	107.07	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	561.12	571.57	10.45	1.9%
		10,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	190.98	12.32	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	202.02	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1118.00	1137.78	19.78	1.8%
		15,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	280.98	12.32	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	296.98	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1674.89	1703.99	29.10	1.7%
UGe	Lindsay	1,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	38.69	18.81	(0.202)	1.97	0.06	(0.13)	(0.038)	0.034	1.90	37.60	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	125.32	125.10	(0.22)	-0.2%
		2,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	56.69	18.81	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	56.59	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	236.69	238.34	1.65	0.7%
		5,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	110.69	18.81	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	113.56	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	570.83	578.07	7.24	1.3%
		10,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	200.69	18.81	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	208.52	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1127.71	1144.28	16.56	1.5%
		15,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	290.69	18.81	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	303.47	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1684.60	1710.49	25.89	1.5%
UGe	Perth	1,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	35.50	16.80	(0.204)	1.97	0.04	(0.13)	(0.038)	0.034	1.88	35.39	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	122.13	122.89	0.76	0.6%
		2,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	53.30	16.80	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	54.18	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	233.30	235.93	2.63	1.1%
		5,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	106.70	16.80	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	110.55	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	566.84	575.06	8.22	1.5%
		10,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	195.70	16.80	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	204.51	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1122.72	1140.26	17.54	1.6%
		15,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	284.70	16.80	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	298.46	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1678.61	1705.47	26.87	1.6%
UGe	Quinte West	1,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	23.74	8.79	(0.212)	1.97	0.06	(0.13)	(0.038)	0.034	1.90	27.57	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	110.37	115.07	4.70	4.3%
		2,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	41.74	8.79	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	46.56	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	221.74	228.31	6.57	3.0%
		5,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	95.74	8.79	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	103.53	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	555.88	568.04	12.16	2.2%
		10,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	185.74	8.79	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	198.49	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1112.76	1134.25	21.48	1.9%
		15,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	275.74	8.79	(0.21)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	293.44	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1669.65	1700.45	30.81	1.8%
UGe	Smiths Falls	1,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	28.02	11.78	(0.209)	1.97	0.04	(0.13)	(0.038)	0.034	1.88	30.36	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	114.65	117.86	3.22	2.8%
		2,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	45.82	11.78	(0.21)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	49.15	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	225.82	230.90	5.08	2.2%
		5,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	99.22	11.78	(0.21)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	105.53	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	559.36	570.03	10.67	1.9%
		10,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	188.22	11.78	(0.21)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	199.48	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1115.24	1135.24	20.00	1.8%
		15,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	277.22	11.78	(0.21)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	293.44	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1671.13	1700.45	29.32	1.8%
UGe	Thorold	1,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	38.02	18.47	(0.202)	1.97	0.06	(0.13)	(0.038)	0.034	1.90	37.26	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	124.65	124.76	0.11	0.1%
		2,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	56.02	18.47	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	56.25	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	236.02	238.00	1.98	0.8%
		5,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	110.02	18.47	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	113.22	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	570.16	577.73	7.57	1.3%
		10,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	200.02	18.47	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	208.18	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1127.04	1143.94	16.89	1.5%
		15,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	290.02	18.47	(0.20)	1.97	0.06	(0.13)	(0.04)	0.034	1.90	303.13	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1683.93	1710.15	26.22	1.6%
UGe	Whitchurch Stouffville	1,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	37.01	17.85	(0.203)	1.97	0.04	(0.13)	(0.038)	0.034	1.88	36.44	0.69	0.74	0.62	0.65	0.70	1.092	21.31	22.18	750	250	65.32	65.32	123.64	123.94	0.30	0.2%
		2,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	54.81	17.85	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	55.23	0.69	0.74	0.62	0.65	0.70	1.092	42.61	44.36	750	1,250	137.39	137.39	234.81	236.98	2.17	0.9%
		5,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	108.21	17.85	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	111.60	0.69	0.74	0.62	0.65	0.70	1.092	106.53	110.89	750	4,250	353.61	353.61	568.35	576.11	7.76	1.4%
		10,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	197.21	17.85	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	205.56	0.69	0.74	0.62	0.65	0.70	1.092	213.05	221.79	750	9,250	713.97	713.97	1124.23	1141.32	17.08	1.5%
		15,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	286.21	17.85	(0.20)	1.97	0.04	(0.13)	(0.04)	0.034	1.88	299.51	0.69	0.74	0.62	0.65	0.70	1.092	319.58	332.68	750	14,250	1074.33	1074.33	1680.12	1706.52	26.41	1.6%

Total Bill Impacts of Proposed Distribution Rates:

Classes		Scenario			2008 Incl Rate Riders								2009 + IRM Incl Rate Riders								Non-Dx Compoent						Other Reg	Other Reg	Commodity Bands				Existing	New	Incr	Incr
					Existing Dx Rates							Existing Dx	New Dx Rates							New Dx	RTSR old	RTSR nev	WMSC old	WMSC new	DRC	TLF old	Old	New	Band 1	Band 2	Old	New	Total Bill	Total Bill	Total Bill	Total Bill
																													-	5.4						
New Class	Old Class	kWh	kW	LF	SrChg	Rider4	base	Rider2	Rider3	Rider4	VarChg	[$/month]	SrChg	Rider4	base	Rider2	Rider3	Rider4	ider 5a & !	VarChg	[$/month]	$/kW	$/kW	c/kWh	c/kWh	c/kWh		$	$	kWhs	kWhs	Total $	Total $	[$/month]	[$/month]	[$/month]	%
					[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]	[$/kW]	[$/kW]		[$/cust]	[$/kW]	[$/kW]	[$/kW]	[$/kW]	[$/kW]	[$/kW]	[$/kW]																	
UGd	Arnprior	15,000	60	35%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	442.5	26.29	0.67	7.18	0.20	(0.51)	0.17	0.09	7.13	454.8	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1676.20	1707.95	31.74	1.9%
		43,164	133	45%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	951.4	26.29	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	975.4	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4388.70	4458.93	70.23	1.6%
		100,000	500	28%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	3,509.8	26.29	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	3,592.7	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	12018.71	12255.46	236.75	2.0%
		400,000	1000	56%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	6,995.3	26.29	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	7,158.3	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38187.61	38722.06	534.45	1.4%
		1,000,000	3000	46%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	20,937.3	26.29	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	21,421.1	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100339.89	101874.17	1534.28	1.5%
		1,500,000	4000	52%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	27,908.3	26.29	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	28,552.5	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145590.47	147688.33	2097.86	1.4%
UGd	Brockville	15,000	60	35%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	412.4	26.16	0.67	7.39	0.12	(0.51)	0.17	0.09	7.25	462.1	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1646.13	1715.17	69.04	4.2%
		43,164	133	45%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	884.8	26.16	0.67	7.39	0.12	(0.51)	0.167	0.09	7.25	991.6	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4322.13	4475.11	152.97	3.5%
		100,000	500	28%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	3,259.7	26.16	0.67	7.39	0.12	(0.51)	0.167	0.09	7.25	3,653.8	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	11768.64	12316.61	547.97	4.7%
		400,000	1000	56%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	6,495.2	26.16	0.67	7.39	0.12	(0.51)	0.167	0.09	7.25	7,280.8	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	37687.54	38844.50	1156.96	3.1%
		1,000,000	3000	46%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	19,437.2	26.16	0.67	7.39	0.12	(0.51)	0.167	0.09	7.25	21,788.7	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	98839.82	102241.76	3401.94	3.4%
		1,500,000	4000	52%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	25,908.2	26.16	0.67	7.39	0.12	(0.51)	0.167	0.09	7.25	29,042.7	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	143590.40	148178.50	4588.10	3.2%
UGd	Carleton Place	15,000	60	35%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	445.1	27.17	0.67	7.18	0.22	(0.51)	0.17	0.09	7.15	456.9	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1678.83	1710.03	31.19	1.9%
		43,164	133	45%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	955.5	27.17	0.67	7.18	0.22	(0.51)	0.167	0.09	7.15	979.0	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4392.79	4462.48	69.68	1.6%
		100,000	500	28%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	3,521.2	27.17	0.67	7.18	0.22	(0.51)	0.167	0.09	7.15	3,603.5	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	12030.14	12266.34	236.20	2.0%
		400,000	1000	56%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	7,016.7	27.17	0.67	7.18	0.22	(0.51)	0.167	0.09	7.15	7,179.2	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38209.04	38742.94	533.90	1.4%
		1,000,000	3000	46%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	20,998.7	27.17	0.67	7.18	0.22	(0.51)	0.167	0.09	7.15	21,482.0	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100401.32	101935.05	1533.73	1.5%
		1,500,000	4000	52%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	27,989.7	27.17	0.67	7.18	0.22	(0.51)	0.167	0.09	7.15	28,633.4	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145671.90	147769.21	2097.31	1.4%
UGd	GBE	15,000	60	35%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	433.6	20.53	0.66	7.18	0.19	(0.51)	0.17	0.09	7.12	448.5	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1667.25	1701.58	34.33	2.1%
		43,164	133	45%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	941.7	20.53	0.66	7.18	0.19	(0.51)	0.167	0.09	7.12	968.3	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4379.02	4451.84	72.82	1.7%
		100,000	500	28%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	3,496.4	20.53	0.66	7.18	0.19	(0.51)	0.167	0.09	7.12	3,581.9	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	12005.36	12244.69	239.33	2.0%
		400,000	1000	56%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	6,976.9	20.53	0.66	7.18	0.19	(0.51)	0.167	0.09	7.12	7,142.6	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38169.26	38706.30	537.04	1.4%
		1,000,000	3000	46%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	20,898.9	20.53	0.66	7.18	0.19	(0.51)	0.167	0.09	7.12	21,385.4	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100301.54	101838.41	1536.87	1.5%
		1,500,000	4000	52%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	27,859.9	20.53	0.66	7.18	0.19	(0.51)	0.167	0.09	7.12	28,506.8	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145542.12	147642.57	2100.45	1.4%
UGd	Lindsay	15,000	60	35%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	443.3	27.02	0.67	7.18	0.19	(0.51)	0.17	0.09	7.12	455.0	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1676.96	1708.07	31.11	1.9%
		43,164	133	45%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	951.4	27.02	0.67	7.18	0.19	(0.51)	0.167	0.09	7.12	974.8	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4388.73	4458.33	69.60	1.6%
		100,000	500	28%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	3,506.1	27.02	0.67	7.18	0.19	(0.51)	0.167	0.09	7.12	3,588.4	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	12015.07	12251.19	236.12	2.0%
		400,000	1000	56%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	6,986.6	27.02	0.67	7.18	0.19	(0.51)	0.167	0.09	7.12	7,149.1	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38178.97	38712.79	533.82	1.4%
		1,000,000	3000	46%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	20,908.6	27.02	0.67	7.18	0.19	(0.51)	0.167	0.09	7.12	21,391.9	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100311.25	101844.90	1533.65	1.5%
		1,500,000	4000	52%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	27,869.6	27.02	0.67	7.18	0.19	(0.51)	0.167	0.09	7.12	28,513.3	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145551.83	147649.06	2097.23	1.4%
UGd	Perth	15,000	60	35%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	436.1	25.00	0.66	7.18	0.12	(0.51)	0.17	0.09	7.05	448.8	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1669.76	1701.86	32.10	1.9%
		43,164	133	45%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	939.1	25.00	0.66	7.18	0.12	(0.51)	0.167	0.09	7.05	963.5	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4376.42	4447.01	70.58	1.6%
		100,000	500	28%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	3,468.1	25.00	0.66	7.18	0.12	(0.51)	0.167	0.09	7.05	3,551.4	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	11977.07	12214.17	237.10	2.0%
		400,000	1000	56%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	6,913.6	25.00	0.66	7.18	0.12	(0.51)	0.167	0.09	7.05	7,077.1	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38105.97	38640.77	534.80	1.4%
		1,000,000	3000	46%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	20,695.6	25.00	0.66	7.18	0.12	(0.51)	0.167	0.09	7.05	21,179.9	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100098.25	101632.89	1534.64	1.5%
		1,500,000	4000	52%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	27,586.6	25.00	0.66	7.18	0.12	(0.51)	0.167	0.09	7.05	28,231.3	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145268.83	147367.04	2098.21	1.4%
UGd	Quinte West	15,000	60	35%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	427.7	17.00	0.66	7.18	0.18	(0.51)	0.17	0.09	7.11	444.3	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1661.41	1697.45	36.04	2.2%
		43,164	133	45%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	935.1	17.00	0.66	7.18	0.18	(0.51)	0.167	0.09	7.11	963.5	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4372.45	4446.98	74.52	1.7%
		100,000	500	28%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	3,486.2	17.00	0.66	7.18	0.18	(0.51)	0.167	0.09	7.11	3,573.4	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	11995.12	12236.16	241.04	2.0%
		400,000	1000	56%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	6,961.7	17.00	0.66	7.18	0.18	(0.51)	0.167	0.09	7.11	7,129.1	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38154.02	38692.76	538.74	1.4%
		1,000,000	3000	46%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	20,863.7	17.00	0.66	7.18	0.18	(0.51)	0.167	0.09	7.11	21,351.8	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100266.30	101804.87	1538.57	1.5%
		1,500,000	4000	52%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	27,814.7	17.00	0.66	7.18	0.18	(0.51)	0.167	0.09	7.11	28,463.2	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145496.88	147599.03	2102.15	1.4%
UGd	Smiths Falls	15,000	60	35%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	429.2	19.98	0.66	7.18	0.13	(0.51)	0.17	0.09	7.06	444.3	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1662.88	1697.44	34.55	2.1%
		43,164	133	45%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	933.0	19.98	0.66	7.18	0.13	(0.51)	0.167	0.09	7.06	959.8	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4370.27	4443.31	73.04	1.7%
		100,000	500	28%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	3,465.6	19.98	0.66	7.18	0.13	(0.51)	0.167	0.09	7.06	3,551.3	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	11974.59	12214.15	239.56	2.0%
		400,000	1000	56%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	6,916.1	19.98	0.66	7.18	0.13	(0.51)	0.167	0.09	7.06	7,082.0	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38108.49	38645.75	537.26	1.4%
		1,000,000	3000	46%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	20,718.1	19.98	0.66	7.18	0.13	(0.51)	0.167	0.09	7.06	21,204.8	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100120.77	101657.86	1537.09	1.5%
		1,500,000	4000	52%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	27,619.1	19.98	0.66	7.18	0.13	(0.51)	0.167	0.09	7.06	28,266.2	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145301.35	147402.02	2100.67	1.4%
UGd	Thorold	15,000	60	35%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	443.2	26.67	0.67	7.18	0.20	(0.51)	0.17	0.09	7.13	455.2	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1676.88	1708.33	31.45	1.9%
		43,164	133	45%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	952.1	26.67	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	975.8	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4389.38	4459.32	69.94	1.6%
		100,000	500	28%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	3,510.4	26.67	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	3,593.0	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	12019.39	12255.84	236.45	2.0%
		400,000	1000	56%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	6,995.9	26.67	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	7,158.7	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38188.29	38722.44	534.15	1.4%
		1,000,000	3000	46%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	20,937.9	26.67	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	21,421.5	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100340.57	101874.56	1533.99	1.5%
		1,500,000	4000	52%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	27,908.9	26.67	0.67	7.18	0.20	(0.51)	0.167	0.09	7.13	28,552.9	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145591.15	147688.71	2097.56	1.4%
UGd	Whitchurch Stouffville	15,000	60	35%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	438.2	26.05	0.67	7.18	0.13	(0.51)	0.17	0.09	7.06	450.4	2.68	2.91	0.62	0.65	0.70	1.06	374.28	393.70	-	15,000	859.41	859.41	1671.88	1703.51	31.63	1.9%
		43,164	133	45%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	942.0	26.05	0.67	7.18	0.13	(0.51)	0.167	0.09	7.06	965.9	2.68	2.91	0.62	0.65	0.70	1.06	964.27	1010.47	-	43,164	2473.04	2473.04	4379.27	4449.39	70.12	1.6%
		100,000	500	28%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	3,474.6	26.05	0.67	7.18	0.13	(0.51)	0.167	0.09	7.06	3,557.4	2.68	2.91	0.62	0.65	0.70	1.06	2779.56	2933.41	-	100,000	5729.40	5729.40	11983.59	12220.22	236.63	2.0%
		400,000	1000	56%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	6,925.1	26.05	0.67	7.18	0.13	(0.51)	0.167	0.09	7.06	7,088.1	2.68	2.91	0.62	0.65	0.70	1.06	8274.76	8646.11	-	400,000	22917.60	22917.60	38117.49	38651.83	534.34	1.4%
		1,000,000	3000	46%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	20,727.1	26.05	0.67	7.18	0.13	(0.51)	0.167	0.09	7.06	21,210.9	2.68	2.91	0.62	0.65	0.70	1.06	22108.64	23159.03	-	1,000,000	57294.00	57294.00	100129.77	101663.94	1534.17	1.5%
		1,500,000	4000	52%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	27,628.1	26.05	0.67	7.18	0.13	(0.51)	0.167	0.09	7.06	28,272.3	2.68	2.91	0.62	0.65	0.70	1.06	31741.22	33194.79	-	1,500,000	85941.00	85941.00	145310.35	147408.10	2097.75	1.4%

Total Bill Impacts of Proposed Distribution Rates:

Classes		Scenario			2008 Incl Rate Riders										2009 + IRM Incl Rate Riders										Non-Dx Compoent						Other Reg Charges		Commodity Bands				Existing	New	Incr	Incr
					Existing Dx Rates								Existing Dx		New Dx Rates									New Dx								Old	New	Band	Band 2	Old	New				
																																	-	5.4						
New Class	Old Class	kWh	kW	LF	SrChg	Rider4	base	Rider2	Rider3	Rider4	VarChg	[$/month]	SrChg	Rider4	base	Rider2	Rider3	Rider4	Rider 5	AB	VarChg	[$/month]	$/kW	$/kW	c/kWh	c/kWh	c/kWh		$	$	kWhs	kWhs	Total $	Total $	Total Bill	Total Bill	Total Bill	Total Bill	
					[$/cust]	[$/cust]	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh		[$/cust]	[$/cust]	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh		c/kWh																			
GSd	Arnprior	15,000	60	35%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	443	30.56	0.45	9.70	0.20	(0.41)	0.105	0.12		9.72	614.1	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,639.9	1,827.1	187.2	11.4%				
		43,164	133	45%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	951	30.56	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	1,323.5	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,308.3	4,718.1	409.9	9.5%				
		100,000	500	28%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	3,510	30.56	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	4,890.2	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,716.3	13,218.7	1,502.4	12.8%				
		400,000	1000	56%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	6,995	30.56	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	9,749.3	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,582.8	40,644.6	3,061.7	8.1%				
		1,000,000	3000	46%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	20,937	30.56	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	29,185.9	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,525.6	107,633.6	9,108.0	9.2%				
		1,500,000	4000	52%	23.61	0.64	7.12	0.20	(0.51)	0.16	6.97	27,908	30.56	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	38,904.1	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	143,171.4	155,366.2	12,194.8	8.5%				
GSd	Brockville	15,000	60	35%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	412	30.43	0.45	9.25	0.12	(0.41)	0.124	0.12		9.21	583.3	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,609.8	1,796.3	186.5	11.6%				
		43,164	133	45%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	885	30.43	0.45	9.25	0.12	(0.41)	0.092	0.120		9.21	1,255.4	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,241.7	4,650.0	408.3	9.6%				
		100,000	500	28%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	3,260	30.43	0.45	9.25	0.12	(0.41)	0.092	0.120		9.21	4,634.4	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,466.3	12,963.0	1,496.8	13.1%				
		400,000	1000	56%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	6,495	30.43	0.45	9.25	0.12	(0.41)	0.092	0.120		9.21	9,238.0	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,082.8	40,133.3	3,050.5	8.2%				
		1,000,000	3000	46%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	19,437	30.43	0.45	9.25	0.12	(0.41)	0.092	0.120		9.21	27,652.2	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	97,025.5	106,100.0	9,074.5	9.4%				
		1,500,000	4000	52%	23.54	0.64	6.70	0.12	(0.51)	0.16	6.47	25,908	30.43	0.45	9.25	0.12	(0.41)	0.092	0.120		9.21	36,859.3	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	141,171.3	153,321.4	12,150.1	8.6%				
GSd	Carleton Place	15,000	60	35%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	445	31.44	0.45	9.70	0.22	(0.41)	0.105	0.12		9.74	616.2	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,642.5	1,829.2	186.6	11.4%				
		43,164	133	45%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	955	31.44	0.45	9.70	0.22	(0.41)	0.092	0.120		9.74	1,327.1	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,312.4	4,721.7	409.3	9.5%				
		100,000	500	28%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	3,521	31.44	0.45	9.70	0.22	(0.41)	0.092	0.120		9.74	4,901.0	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,727.8	13,229.6	1,501.9	12.8%				
		400,000	1000	56%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	7,017	31.44	0.45	9.70	0.22	(0.41)	0.092	0.120		9.74	9,770.2	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,604.3	40,665.5	3,061.2	8.1%				
		1,000,000	3000	46%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	20,999	31.44	0.45	9.70	0.22	(0.41)	0.092	0.120		9.74	29,246.7	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,587.0	107,694.5	9,107.5	9.2%				
		1,500,000	4000	52%	25.04	0.64	7.12	0.22	(0.51)	0.16	6.99	27,990	31.44	0.45	9.70	0.22	(0.41)	0.092	0.120		9.74	38,985.0	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	143,252.8	155,447.1	12,194.3	8.5%				
GSd	GBE	15,000	60	35%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	434	24.80	0.44	9.68	0.19	(0.41)	0.107	0.12		9.69	606.7	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,631.0	1,819.7	188.7	11.6%				
		43,164	133	45%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	942	24.80	0.44	9.68	0.19	(0.41)	0.092	0.120		9.69	1,314.0	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,298.6	4,708.6	410.0	9.5%				
		100,000	500	28%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	3,496	24.80	0.44	9.68	0.19	(0.41)	0.092	0.120		9.69	4,870.3	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,703.0	13,198.9	1,495.9	12.8%				
		400,000	1000	56%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	6,977	24.80	0.44	9.68	0.19	(0.41)	0.092	0.120		9.69	9,715.3	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,564.5	40,610.6	3,046.1	8.1%				
		1,000,000	3000	46%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	20,899	24.80	0.44	9.68	0.19	(0.41)	0.092	0.120		9.69	29,095.5	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,487.2	107,543.3	9,056.1	9.2%				
		1,500,000	4000	52%	15.26	0.64	7.12	0.19	(0.51)	0.16	6.96	27,860	24.80	0.44	9.68	0.19	(0.41)	0.092	0.120		9.69	38,785.6	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	143,123.0	155,247.7	12,124.7	8.5%				
GSd	Lindsay	15,000	60	35%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	443	31.29	0.45	9.72	0.19	(0.41)	0.103	0.12		9.73	615.3	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,640.7	1,828.3	187.7	11.4%				
		43,164	133	45%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	951	31.29	0.45	9.72	0.19	(0.41)	0.092	0.120		9.73	1,325.4	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,308.3	4,720.0	411.7	9.6%				
		100,000	500	28%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	3,506	31.29	0.45	9.72	0.19	(0.41)	0.092	0.120		9.73	4,895.0	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,712.7	13,223.6	1,510.9	12.9%				
		400,000	1000	56%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	6,987	31.29	0.45	9.72	0.19	(0.41)	0.092	0.120		9.73	9,758.2	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,574.2	40,653.5	3,079.3	8.2%				
		1,000,000	3000	46%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	20,909	31.29	0.45	9.72	0.19	(0.41)	0.092	0.120		9.73	29,211.1	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,496.9	107,658.9	9,161.9	9.3%				
		1,500,000	4000	52%	24.97	0.64	7.12	0.19	(0.51)	0.16	6.96	27,870	31.29	0.45	9.72	0.19	(0.41)	0.092	0.120		9.73	38,937.6	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	143,132.8	155,399.7	12,266.9	8.6%				
GSd	Perth	15,000	60	35%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	436	29.27	0.45	9.70	0.12	(0.41)	0.105	0.12		9.64	608.0	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,633.5	1,821.0	187.5	11.5%				
		43,164	133	45%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	939	29.27	0.45	9.70	0.12	(0.41)	0.092	0.120		9.64	1,311.6	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,296.0	4,706.2	410.2	9.5%				
		100,000	500	28%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	3,468	29.27	0.45	9.70	0.12	(0.41)	0.092	0.120		9.64	4,848.9	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,674.7	13,177.5	1,502.8	12.9%				
		400,000	1000	56%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	6,914	29.27	0.45	9.70	0.12	(0.41)	0.092	0.120		9.64	9,668.0	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,501.2	40,563.3	3,062.1	8.2%				
		1,000,000	3000	46%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	20,696	29.27	0.45	9.70	0.12	(0.41)	0.092	0.120		9.64	28,944.6	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,283.9	107,392.3	9,108.4	9.3%				
		1,500,000	4000	52%	21.97	0.64	7.12	0.12	(0.51)	0.16	6.89	27,587	29.27	0.45	9.70	0.12	(0.41)	0.092	0.120		9.64	38,582.9	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	142,849.8	155,044.9	12,195.2	8.5%				
GSd	Quinte West	15,000	60	35%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	428	21.27	0.44	9.68	0.18	(0.41)	0.107	0.12		9.68	602.5	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,625.1	1,815.5	190.4	11.7%				
		43,164	133	45%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	935	21.27	0.44	9.68	0.18	(0.41)	0.092	0.120		9.68	1,309.2	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,292.0	4,703.8	411.7	9.6%				
		100,000	500	28%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	3,486	21.27	0.44	9.68	0.18	(0.41)	0.092	0.120		9.68	4,861.8	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,692.7	13,190.4	1,497.6	12.8%				
		400,000	1000	56%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	6,962	21.27	0.44	9.68	0.18	(0.41)	0.092	0.120		9.68	9,701.8	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,549.3	40,597.1	3,047.8	8.1%				
		1,000,000	3000	46%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	20,864	21.27	0.44	9.68	0.18	(0.41)	0.092	0.120		9.68	29,062.0	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,452.0	107,509.8	9,057.8	9.2%				
		1,500,000	4000	52%	10.02	0.64	7.12	0.18	(0.51)	0.16	6.95	27,815	21.27	0.44	9.68	0.18	(0.41)	0.092	0.120		9.68	38,742.1	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	143,077.8	155,204.2	12,126.4	8.5%				
GSd	Smiths Falls	15,000	60	35%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	429	24.25	0.44	9.68	0.13	(0.41)	0.107	0.12		9.63	602.5	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,626.6	1,815.5	188.9	11.6%				
		43,164	133	45%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	933	24.25	0.44	9.68	0.13	(0.41)	0.092	0.120		9.63	1,305.5	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,289.8	4,700.1	410.3	9.6%				
		100,000	500	28%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	3,466	24.25	0.44	9.68	0.13	(0.41)	0.092	0.120		9.63	4,839.7	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,672.2	13,168.3	1,496.1	12.8%				
		400,000	1000	56%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	6,916	24.25	0.44	9.68	0.13	(0.41)	0.092	0.120		9.63	9,654.8	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,503.7	40,550.1	3,046.4	8.1%				
		1,000,000	3000	46%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	20,718	24.25	0.44	9.68	0.13	(0.41)	0.092	0.120		9.63	28,915.0	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,306.5	107,362.7	9,056.3	9.2%				
		1,500,000	4000	52%	14.49	0.64	7.12	0.13	(0.51)	0.16	6.90	27,619	24.25	0.44	9.68	0.13	(0.41)	0.092	0.120		9.63	38,545.1	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	142,882.3	155,007.2	12,124.9	8.5%				
GSd	Thorold	15,000	60	35%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	443	30.94	0.45	9.70	0.20	(0.41)	0.105	0.12		9.72	614.5	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,640.6	1,827.5	186.9	11.4%				
		43,164	133	45%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	952	30.94	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	1,323.9	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,308.9	4,718.5	409.6	9.5%				
		100,000	500	28%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	3,510	30.94	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	4,890.5	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,717.0	13,219.1	1,502.1	12.8%				
		400,000	1000	56%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	6,996	30.94	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	9,749.7	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,583.5	40,645.0	3,061.4	8.1%				
		1,000,000	3000	46%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	20,938	30.94	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	29,186.2	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,526.3	107,634.0	9,107.7	9.2%				
		1,500,000	4000	52%	24.29	0.64	7.12	0.20	(0.51)	0.16	6.97	27,909	30.94	0.45	9.70	0.20	(0.41)	0.092	0.120		9.72	38,904.5	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	143,172.1	155,366.6	12,194.5	8.5%				
GSd	Whitchurch Stouffville	15,000	60	35%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	438	30.32	0.45	9.70	0.13	(0.41)	0.105	0.12		9.65	609.7	2.11	2.28	0.62	0.65	0.7	1.061	338.0	353.6	-	15,000	859.4	859.4	1,635.6	1,822.7	187.1	11.4%				
		43,164	133	45%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	942	30.32	0.45	9.70	0.13	(0.41)	0.092	0.120		9.65	1,314.0	2.11	2.28	0.62	0.65	0.70	1.061	883.8	921.6	-	43,164	2,473.0	2,473.0	4,298.8	4,708.6	409.8	9.5%				
		100,000	500	28%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	3,475	30.32	0.45	9.70	0.13	(0.41)	0.092	0.120		9.65	4,854.9	2.11	2.28	0.62	0.65	0.70	1.061	2,477.2	2,599.2	-	100,000	5,729.4	5,729.4	11,681.2	13,183.5	1,502.3	12.9%				
		400,000	1000	56%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	6,925	30.32	0.45	9.70	0.13	(0.41)	0.092	0.120		9.65	9,679.1	2.11	2.28	0.62	0.65	0.70	1.061	7,670.0	7,977.7	-	400,000	22,917.6	22,917.6	37,512.7	40,574.3	3,061.6	8.2%				
		1,000,000	3000	46%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	20,727	30.32	0.45	9.70	0.13	(0.41)	0.092	0.120		9.65	28,975.6	2.11	2.28	0.62	0.65	0.70	1.061	20,294.3	21,153.7	-	1,000,000	57,294.0	57,294.0	98,315.5	107,423.4	9,107.9	9.3%				
		1,500,000	4000	52%	23.49	0.64	7.12	0.13	(0.51)	0.16	6.90	27,628	30.32	0.45	9.70	0.13	(0.41)	0.092	0.120		9.65	38,623.9	2.11	2.28	0.62	0.65	0.70	1.061	29,322.1	30,521.1	-	1,500,000	85,941.0	85,941.0	142,891.3	155,086.0	12,194.7	8.5%				

Total Bill Impacts of Proposed Distribution Rates:

Classes		Scenario	2008 Incl Rate Riders								2009 + IRM Incl Rate Riders									Non-Dx Compoent						Other Reg Charges		750.0 Commodity Bands				Existing	New	Incr	Incr
			Existing Dx Rates							Existing Dx	New Dx Rates								New Dx	RTSR old	RTSR new	WMSC old	WMSC new	DRC	TLF old	Old	New	Band 1 5.7	Band 2 6.6	Old	New	Total Bill	Total Bill	Total Bill	Total Bill
New Class	Old Class	kWh	SrChg	Rider4	base	Rider2	Rider3	Rider4	VarChg	[$/month]	SrChg	Rider4	base	Rider2	Rider3	Rider4	Rider 5AB	VarChg	[$/month]	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh		$	$	kWhs	kWhs	Total $	Total $	[$/month]	[$/month]	[$/month	%
			[$/cust]	[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]		[$/cust]	[$/cust]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]	[c/kWh]																	
GSe	Arnprior	1,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	37.3	22.96	0.40	2.58	0.06	(0.13)	0.0418	0.062	2.61	49.5	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	123.7	136.9	13.2	10.6%
		2,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	55.3	22.96	0.40	2.58	0.06	(0.13)	0.044	0.062	2.61	75.6	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	234.9	257.2	22.3	9.5%
		5,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	109.3	22.96	0.40	2.58	0.06	(0.13)	0.044	0.062	2.61	154.1	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	568.4	618.0	49.6	8.7%
		10,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	199.3	22.96	0.40	2.58	0.06	(0.13)	0.044	0.062	2.61	284.7	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,124.2	1,219.4	95.2	8.5%
		15,000	19.55	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	289.3	22.96	0.40	2.58	0.06	(0.13)	0.044	0.062	2.61	415.4	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,680.0	1,820.8	140.9	8.4%
GSe	Brockville	1,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	37.1	22.83	0.40	2.58	0.04	(0.13)	0.0418	0.062	2.59	49.2	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	123.5	136.6	13.1	10.6%
		2,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	54.9	22.83	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	75.1	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	234.4	256.6	22.2	9.5%
		5,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	108.3	22.83	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	152.9	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	567.3	616.9	49.6	8.7%
		10,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	197.3	22.83	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	282.6	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,122.1	1,217.3	95.2	8.5%
		15,000	19.48	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	286.3	22.83	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	412.3	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,676.9	1,817.7	140.8	8.4%
GSe	Carleton Place	1,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	38.9	23.84	0.40	2.62	0.07	(0.13)	0.0428	0.062	2.67	50.9	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	125.3	138.3	13.0	10.4%
		2,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	57.0	23.84	0.40	2.62	0.07	(0.13)	0.044	0.062	2.67	77.6	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	236.5	259.1	22.6	9.5%
		5,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	111.3	23.84	0.40	2.62	0.07	(0.13)	0.044	0.062	2.67	157.5	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	570.3	621.5	51.2	9.0%
		10,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	201.8	23.84	0.40	2.62	0.07	(0.13)	0.044	0.062	2.67	290.8	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,126.6	1,225.4	98.8	8.8%
		15,000	20.98	(0.22)	1.91	0.07	(0.13)	(0.04)	1.81	292.3	23.84	0.40	2.62	0.07	(0.13)	0.044	0.062	2.67	424.0	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,682.9	1,829.4	146.5	8.7%
GSe	GBE	1,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	29.0	17.20	0.40	2.41	0.06	(0.13)	0.0417	0.062	2.44	42.0	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	115.4	129.4	14.0	12.2%
		2,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	47.0	17.20	0.40	2.41	0.06	(0.13)	0.044	0.062	2.44	66.5	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	226.5	248.0	21.5	9.5%
		5,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	101.0	17.20	0.40	2.41	0.06	(0.13)	0.044	0.062	2.44	139.8	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	560.0	603.7	43.7	7.8%
		10,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	191.0	17.20	0.40	2.41	0.06	(0.13)	0.044	0.062	2.44	262.0	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,115.8	1,196.6	80.8	7.2%
		15,000	11.20	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	281.0	17.20	0.40	2.41	0.06	(0.13)	0.044	0.062	2.44	384.1	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,671.6	1,789.5	117.9	7.1%
GSe	Lindsay	1,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	38.7	23.69	0.40	2.62	0.06	(0.13)	0.0410	0.062	2.65	50.6	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	125.1	138.0	12.9	10.3%
		2,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	56.7	23.69	0.40	2.62	0.06	(0.13)	0.044	0.062	2.65	77.2	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	236.3	258.7	22.4	9.5%
		5,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	110.7	23.69	0.40	2.62	0.06	(0.13)	0.044	0.062	2.65	156.7	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	569.7	620.7	51.0	8.9%
		10,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	200.7	23.69	0.40	2.62	0.06	(0.13)	0.044	0.062	2.65	289.4	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,125.5	1,224.1	98.5	8.8%
		15,000	20.91	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	290.7	23.69	0.40	2.62	0.06	(0.13)	0.044	0.062	2.65	422.0	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,681.3	1,827.4	146.1	8.7%
GSe	Perth	1,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	35.5	21.67	0.40	2.55	0.04	(0.13)	0.0418	0.062	2.56	47.7	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	121.9	135.1	13.2	10.8%
		2,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	53.3	21.67	0.40	2.55	0.04	(0.13)	0.044	0.062	2.56	73.3	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	232.9	254.9	22.0	9.5%
		5,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	106.7	21.67	0.40	2.55	0.04	(0.13)	0.044	0.062	2.56	150.3	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	565.7	614.2	48.5	8.6%
		10,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	195.7	21.67	0.40	2.55	0.04	(0.13)	0.044	0.062	2.56	278.5	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,120.5	1,213.1	92.6	8.3%
		15,000	17.92	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	284.7	21.67	0.40	2.55	0.04	(0.13)	0.044	0.062	2.56	406.6	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,675.3	1,812.0	136.7	8.2%
GSe	Quinte West	1,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	23.7	13.67	0.39	2.30	0.06	(0.13)	0.0425	0.062	2.33	37.4	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	110.1	124.8	14.7	13.3%
		2,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	41.7	13.67	0.39	2.30	0.06	(0.13)	0.044	0.062	2.33	60.8	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	221.3	242.3	21.0	9.5%
		5,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	95.7	13.67	0.39	2.30	0.06	(0.13)	0.044	0.062	2.33	130.8	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	554.8	594.7	40.0	7.2%
		10,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	185.7	13.67	0.39	2.30	0.06	(0.13)	0.044	0.062	2.33	247.5	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,110.6	1,182.2	71.6	6.4%
		15,000	5.96	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	275.7	13.67	0.39	2.30	0.06	(0.13)	0.044	0.062	2.33	364.2	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,666.4	1,769.6	103.2	6.2%
GSe	Smiths Falls	1,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	28.0	16.65	0.40	2.39	0.04	(0.13)	0.0426	0.062	2.40	41.1	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	114.4	128.5	14.1	12.3%
		2,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	45.8	16.65	0.40	2.39	0.04	(0.13)	0.044	0.062	2.40	65.1	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	225.4	246.7	21.3	9.4%
		5,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	99.2	16.65	0.40	2.39	0.04	(0.13)	0.044	0.062	2.40	137.3	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	558.3	601.2	43.0	7.7%
		10,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	188.2	16.65	0.40	2.39	0.04	(0.13)	0.044	0.062	2.40	257.5	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,113.1	1,192.2	79.1	7.1%
		15,000	10.44	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	277.2	16.65	0.40	2.39	0.04	(0.13)	0.044	0.062	2.40	377.7	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,667.9	1,783.1	115.3	6.9%
GSe	Thorold	1,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	38.0	23.34	0.40	2.60	0.06	(0.13)	0.0419	0.062	2.63	50.1	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	124.4	137.5	13.0	10.5%
		2,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	56.0	23.34	0.40	2.60	0.06	(0.13)	0.044	0.062	2.63	76.4	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	235.6	258.0	22.4	9.5%
		5,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	110.0	23.34	0.40	2.60	0.06	(0.13)	0.044	0.062	2.63	155.4	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	569.1	619.4	50.3	8.8%
		10,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	200.0	23.34	0.40	2.60	0.06	(0.13)	0.044	0.062	2.63	287.1	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,124.9	1,221.8	96.9	8.6%
		15,000	20.24	(0.22)	1.91	0.06	(0.13)	(0.04)	1.80	290.0	23.34	0.40	2.60	0.06	(0.13)	0.044	0.062	2.63	418.8	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,680.7	1,824.2	143.5	8.5%
GSe	Whitchurch Stouffville	1,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	37.0	22.73	0.40	2.58	0.04	(0.13)	0.0427	0.062	2.59	49.1	0.67	0.73	0.62	0.65	0.70	1.092	21.1	22.1	750	250	65.3	65.3	123.4	136.5	13.1	10.6%
		2,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	54.8	22.73	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	75.0	0.67	0.73	0.62	0.65	0.70	1.092	42.2	44.1	750	1,250	137.4	137.4	234.4	256.6	22.2	9.5%
		5,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	108.2	22.73	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	152.9	0.67	0.73	0.62	0.65	0.70	1.092	105.4	110.3	750	4,250	353.6	353.6	567.3	616.8	49.6	8.7%
		10,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	197.2	22.73	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	282.6	0.67	0.73	0.62	0.65	0.70	1.092	210.9	220.7	750	9,250	714.0	714.0	1,122.0	1,217.3	95.2	8.5%
		15,000	19.43	(0.22)	1.91	0.04	(0.13)	(0.04)	1.78	286.2	22.73	0.40	2.58	0.04	(0.13)	0.044	0.062	2.59	412.4	0.67	0.73	0.62	0.65	0.70	1.092	316.3	331.0	750	14,250	1,074.3	1,074.3	1,676.8	1,817.7	140.9	8.4%

Ontario Energy Board (Board Staff) INTERROGATORY #140 List 1

Interrogatory

Issue 7.4 Are the proposed rate impact mitigation plans appropriate and are the resulting customer bill impacts reasonable?

140. Ref: ExhG1/Tab4/Sch4/p2

Sub Transmission Class: Please describe the cost basis for the rates proposed for Common ST Lines, Specific ST Lines, and Specific Primary Lines, including a brief explanation of why the former is proposed to increase considerably and the latter two to decrease from the currently approved rates.

Response

The Common ST Line rate is proposed to increase from the currently approved rate due to the increased revenue requirement. The Common ST Line rate is set to recover the remaining ST revenue requirement from the OEB Cost Allocation Model that are not recovered by the HVDS-High, HVDS-Low, LVDS-Low, Specific ST lines, Specific Primary line, Meter and Fixed charges.

The revenue recovered for the above-mentioned rates are calculated as follows:

The HVDS-High rate is set to equal the RTSR Transformation Connection charge uplifted for losses. This ensures that customers pay the same rate for transformation from the Transmission system to the ST system.

The HVDS-Low rate is set such that customers pay the same for transformation from the Transmission system to the Primary Distribution system, which is the sum of the HVDS-High rate and the LVDS-Low rate.

The LVDS-Low rate is set to recover the ST costs for Distribution Station Equipment from the OEB Cost Allocation Model as well as a portion of other ST costs – supervision and engineering, DS facility maintenance, general admin and other expenses.

The HVDS-High, HVDS-Low and LVDS-Low rates multiplied by ST customer demand produce the revenue recovered by these rates.

To calculate the Specific Line rates, the cost of the distribution lines from the OEB Cost Allocation Model are divided by the unit-cost-weighted lengths of ST line and Primary line. The Specific Line rates are multiplied by the length of the feeder to determine the

amount recovered. In Proceeding EB-2007-0681, the Specific line charges were designed to recover all the fixed revenue requirement for the ST class as determined in the Cost Allocation Model. Hydro One now does not see this requirement as necessary and that is the reason that the now proposed Specific line charges are lower than the currently approved Specific line charges.

The fixed service charge is the sum of the Smart Meter Adder and the ST value for Customer Unit Cost per month - Minimum System with PLCC Adjustment (i.e. Method C of determining fixed charges) in the Cost Allocation Model adjusted to exclude Wholesale and LV meter costs. The revenue recovered is determined by the fixed service charge multiplied by the number of ST delivery points.

The Wholesale and LV metering costs that are excluded from the fixed service charge are recovered by the Meter Charge, which is multiplied by the count of the HONI owned ST meter points.

All of the above was calculated at a revenue-cost ratio of 1. The LVDS-Low, Specific ST Line, Specific Primary Line, Common ST Line rates and Fixed Service and Meter charges were increased by 1% to achieve a revenue-cost ratio of 1.01, which is the revenue to cost ratio calculated in the cost allocation model for the ST class, as shown in Exhibit G1, Tab 3, Schedule 1, Table 1, page 3.

Ontario Energy Board (Board Staff) INTERROGATORY #141 List 1

Interrogatory

Issue 7.4 Are the proposed rate impact mitigation plans appropriate and are the resulting customer bill impacts reasonable?

Ref: ExhG1/Tab4/Sch4/p4 and ExhG2/Tab1/Sch1/Attachment 1/p37

Sub Transmission Class: Please describe the cost basis for the ST monthly service charge and meter charge, including a brief explanation of why it is proposed to increase considerably from the currently approved rate. Please indicate relevant results in the Hydro One cost allocation study, if applicable.

Response

To calculate the fixed service charge, the Wholesale and LV meter costs were set to equal zero in the OEB Cost Allocation Model, which adjusts the value allocated to ST for Customer Unit Cost per month - Minimum System with PLCC Adjustment (i.e. Method C of determining fixed charges) to exclude meter-related costs.

The fixed service charge is the adjusted value divided by the number of ST delivery points. The reason for the substantial increase in the fixed service charge is attributable to the increase in overall net revenue requirement and decrease in number of ST delivery points.

Please refer to Exhibit H, Tab 1, Schedule 142, for a description of the derivation of the meter charge.

Ontario Energy Board (Board Staff) INTERROGATORY #142 List 1

Interrogatory

Issue 7.4 Are the proposed rate impact mitigation plans appropriate and are the resulting customer bill impacts reasonable?

Ref: ExhG1/Tab4/Sch4/p4 and ExhG2/Tab1/Sch1/Attachment 1/p37

Sub Transmission Class: Please describe the cost basis for the ST meter charge, and in particular please provide a comparison between the proposed meter charge at $445.81 versus the Avoided Cost per ST Customer at $176.53 derived in the cost allocation study.

Response

The Wholesale and LV metering costs that are excluded from the fixed service charge are recovered by the Meter Charge.

The ST net revenue requirement is $31M. This is based on $32M in costs allocated to ST based on Allocated External Revenues, excluding $1M in Unique Allocation of External Revenues from the OEB Cost Allocation Model. The Wholesale and LV meter costs are set to equal zero and removed from the model, which adjusts the ST net revenue requirement from $31M to $28M. The $3M difference is the revenue requirement for the Meter Charge.

To calculate the meter rate, the $3M revenue requirement is divided by 521 HONI-owned meter points. The Meter Charge, at a revenue to cost ratio of 1, is $441.40 and increases to $445.81 at the 1.01 revenue to cost ratio.

This is a different approach from calculating the Avoided Cost per ST customer value determined in the Cost Allocation model.

Ontario Energy Board (Board Staff) INTERROGATORY #143 List 1

Interrogatory

Issue 8.4 Is Hydro One's regulatory treatment of Smart Meter costs appropriate including the smart meter funding adders proposed for 2010/2011?

Ref: ExhF1/Tab1/Sch3

Hydro One is applying for a rate adder of $2.17 and $4.45 per metered customer per month for the years 2010 and 2011. Hydro One is also proposing to include in rate base costs for all smart meters installed as of December 31, 2008.

a) Please complete tables similar to the following that shows the number of smart meters installed and annual gross expenditures, both actual and estimated, by year. Include a calculation of cost per meter for each year. In addition complete similar tables providing the cumulative costs.
   I. Showing minimum functionality costs only
   II. Showing beyond minimum functionality costs only
   III. Showing both minimum and beyond minimum functionality combined.

		2006	2007	2008	2009	2010	2011
By Year							
# of Smart Meters Installed	**A**						
All Meter Installations							
AMI Infrastructure							
MDMR Integration							
WiMax							
Customer Information System							
OM&A included in COS application							
OM&A included in Rate Adder request							
Annual Total	**B**						
Total Cost Per Meter	**C = B / A**						
Cummulative							
Cummulative Meters Installed	**A**						
All Meter Installations							
AMI Infrastructure							
MDMR Integration							
WiMax							
Customer Information System							
OM&A included in COS application							
OM&A included in Rate Adder request							
Cummulative Total	**B**						
Cummulative Cost Per Meter	**C = B / A**						

b) Please compare and contrast any changes occurring each year for the cost per meter where the cost per meter varies +-10%.

c) Has Hydro One included in OM&A expenses for the test years 2010 and 2011 any smart meter related OM&A expenses? If so please identify those expenses for each year including the root source of those expenses.
d) Please confirm that the OM&A expenses included in the applied for rate adders related to the incremental number of smart meters installed each year?

Response

a) Please see Table 1 – Smart Meter Capital and OM&A by Year and Table 2 – Smart Meter Capital and OM&A Cumulative below.

By Year

Table 1 - Capital and OM&A Expenses by Year

$K	2006 Act	2007 Act	2008 Act	2009 Forecast	2010 Forecast	2011 Forecast
# of Smart Meters Installed	27,600	222,831	456,019	370,000	115,000	
Minimum Functionality						
All Meter Installations	4,463	59,897	78,643	123,084	77,016	17,461
AMI Infrastructure	950	5,074	1,632	2,144		1,506
MDMR Integration						
Wimax						
Customer Information System						
OM&A Included in COS Application					6,709	6,943
OM&A Included in Rate Adder Request	3,860	6,212	6,945	14,616	7,635	8,046
Annual Total	9,273	71,183	87,219	139,843	91,359	33,957
Exceeding Minimum Functionality						
All Meter Installations	182	4,115	14,357	9,290	3,546	418
AMI Infrastructure						
MDMR Integration	70	3,780	2,465	21,772	16,918	11,400
Wimax	968					13,540
Customer Information System	1,035	4,639	9,141	10,421	5,646	
OM&A Included in COS Application						
OM&A Included in Rate Adder Request	163			84	7,769	7,356
Annual Total	2,418	12,534	25,962	41,567	33,879	32,714
CDM Funding - Capital	6,400					
- OM&A	881					
Total						
All Meter Installations	4,645	64,012	92,999	132,374	80,562	17,879
AMI Infrastructure	950	5,074	1,632	2,144		1,506
MDMR Integration	70	3,780	2,465	21,772	16,918	11,400
Wimax	968					13,540
Customer Information System	1,035	4,639	9,141	10,421	5,646	
CDM Funding - Capital	6,400					
OM&A Included in COS Application					6,709	6,943
OM&A Included in Rate Adder Request	4,023	6,212	6,945	14,700	15,403	15,402
CDM Funding - OM&A	881					
Annual Total	18,971	83,717	113,181	181,410	125,238	66,671
Total Cost Per Meter	$687.37	$375.70	$248.19	$490.30	$1,089.03	
% Change from Previous Year		-45%	-34%	98%	122%	

Cumulative

Table 2 - Capital and OM&A Expenses Cummulative

$K	2006 Act	2007 Act	2008 Act	2009 Forecast	2010 Forecast	2011 Forecast
# of Smart Meters Installed	27,600	250,431	706,450	1,076,450	1,191,450	1,191,450
Minimum Functionality						
All Meter Installations	4,463	64,360	143,003	266,087	343,102	360,564
AMI Infrastructure	950	6,024	7,655	9,799	9,799	11,305
MDMR Integration						
Wimax						
Customer Information System						
OM&A Included in COS Application					6,709	13,653
OM&A Included in Rate Adder Request	3,860	10,072	17,017	31,632	39,267	47,313
Annual Total	9,273	80,456	167,675	307,518	398,877	432,834
Exceeding Minimum Functionality						
All Meter Installations	182	4,297	18,653	27,943	31,489	31,907
AMI Infrastructure						
MDMR Integration	70	3,851	6,315	28,087	45,005	56,406
Wimax	968	968	968	968	968	14,507
Customer Information System	1,035	5,674	14,815	25,235	30,881	30,881
OM&A Included in COS Application						
OM&A Included in Rate Adder Request	163	163	163	247	8,016	15,372
Annual Total	2,418	14,952	40,914	82,481	116,359	149,073
CDM Funding - Capital	6,400	6,400	6,400	6,400	6,400	6,400
- OM&A	881	881	881	881	881	881
Total						
All Meter Installations	4,645	68,657	161,656	294,030	374,591	392,471
AMI Infrastructure	950	6,024	7,655	9,799	9,799	11,305
MDMR Integration	70	3,851	6,315	28,087	45,005	56,406
Wimax	968	968	968	968	968	14,507
Customer Information System	1,035	5,674	14,815	25,235	30,881	30,881
CDM Funding - Capital	6,400	6,400	6,400	6,400	6,400	6,400
OM&A Included in COS Application					6,709	13,653
OM&A Included in Rate Adder Request	4,023	10,235	17,180	31,880	47,283	62,684
CDM Funding - OM&A	881	881	881	881	881	881
Annual Total	18,971	102,689	215,870	397,279	522,517	589,188
Total Cost Per Meter	$687.37	$410.05	$305.57	$369.06	$438.56	$494.51
% Change from Previous Year		-40%	-25%	21%	19%	13%

b) Per Meter Costs for Table 1

1. Unit costs start higher in 2006 due to up front costs of automating the change meter order process from a manual process to a fully automated system, spread over a low number of meter installs.
2. Dropping unit costs in 2007 reflect installation of smart meters focused on the mass deployment of readily accessible low cost residential and small commercial meters utilizing the automation established in 2006.
3. Unit costs continue to fall in 2008 due to a large number of meters installed in mass deployment partially offset by increases in CIS costs due to bill format specifications being finalized allowing tariff modeling and related service order development to proceed.
4. In 2009 unit costs increase due to increased back office activity associated with Integration and CIS once the MDMR and bill format specifications were finalized in late 2008. Meter installations begin to move into more rural areas with higher

associated replacement costs. Meter socket adapters are introduced for odd form meters. Sweep behind (second trip or changes that were initially skipped) is initiated where meters that were inaccessible during mass deployment are scheduled for replacement with customers. A ramp up of AMRC (Advanced Metering Regional Collector) and repeater installations also occurs in 2009.

5. In 2010 the per meter costs are higher because of the low number of meters coupled with finishing the high cost, low density installations as well as installing a large number of AMRC's and repeaters. General Service customers are included and we begin to convert some customers who are greater than 50 kW. MDMR integration costs are highest in this period as testing activities are being finalized and customer migration begins.
6. In 2011 there are no meter installations but costs to complete the network continue, as well as WiMax installations for areas not covered by cellular providers where this alternate backhaul method is required. Ongoing adjustments and associated testing are expected for MDMR Integration through this period.

The variance in cumulative per unit costs shown in Table 2 follow the same pattern and are subject to the same rationale as those discussed above in Table 1.

c) Yes, OM&A costs of $6.7 Million and $6.9 Million are included for 2010 and 2011 for meters installed prior to 2009 as discussed in Exhibit C1, Tab 2, Schedule 2, page 28. Please refer to Exhibit H, Tab 9, Schedule 11 for details on the components making up these costs.

d) Yes, the OM&A expenses included in the applied for rate adders relate to the incremental number of smart meters installed each year.

Ontario Energy Board (Board Staff) INTERROGATORY #144 List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Ref: ExhA/Tab14/Sch/p1

Hydro One submitted an OM & A and Capital summary of the first five years of its proposed Distribution Green Energy Plan on this page. (Note: Definition of Technical Terms noted below are as per Definitions noted at Exhibit A, Tab 4, Schedule 1, page 5)

a) Please expand the table on page 1 of Exhibit A, Tab 14, Schedule 2 by two additional columns with the first additional column headed as **2015-2017 OM&A and Capital** and the second additional column headed **2018-2020 OM&A and Capital.**

b) Please provide Hydro One's existing status regarding the following: 1) % of primary distribution feeders able to accommodate reverse power flow; 2) % of distribution switching devices capable of being switched remotely; 3) % of distribution stations under full SCADA automation; and 4) % of primary distribution feeders with full DVAR automated support and voltage monitoring.

c) Please provide Hydro One's five and ten year end state forecast for the following categories: 1) % of feeders able to accommodate reverse power flow; 2) % of distribution switching devices capable of being switched remotely; 3) % of distribution stations under full SCADA automation; and 4) % of distribution feeders with full DVAR automated support and voltage monitoring.

Response

a) Hydro One's current business plan does not have information on OM&A and Capital expenditures on Green Energy Plan related work beyond 2014. Hydro One cannot reasonably forecast its Green Energy Plan investments over the requested time periods.

b)

1. 0%
2. 1%
3. 1%
4. 0%

c) 5-year forecast is below. Hydro One does not have a 10-year forecast at this time.

1. 15%
2. 9%
3. 55%
4. 15%

Ontario Energy Board (Board Staff) INTERROGATORY #145 List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

145. Ref: ExhA/Tab14/Sch2/p7 &16
The applicant states that it intends to construct a new TS along with approximately six express feeders (among other facilities) in southwestern Ontario to allow for the connection of new anticipated renewable resources.

a) In installing these new express feeders (for supply anticipated to be 3,500 MW by 2011 and supply of an additional anticipated 3,500 MW by 2014), have studies been carried out on how this could alter load and VAR flows on Hydro One 230 kV and 500 kV transmission lines in the area?

b) If these studies have been carried out, please advise how the magnitude and direction of these flows could be altered by the additional distributed renewable supply for the following 230 kV and 500 kV circuits.

500 kV Circuits	**230 kV Circuits**
Bruce to Milton/Claireville	Hanover to Orangeville
Bruce to Longwood	Bruce to Detweiller
Longwood to Nanticoke	Longwood to Lambton
	Buchanen to Sarnia Scott
	Buchanen to the Chatham Kent area

c) If load and VAR flows could be altered for any of these transmission circuits in a material way, is Hydro One planning any mitigation as a result of these proposed renewable connections and if so what kind of mitigation is Hydro One proposing and if no mitigation is proposed, why not?

d) In installing these new express feeders for the incorporation of additional distributed renewable generation, have studies been carried out on how this could alter base load generation "run times" in the Bruce and Windsor areas?

Response

a) Studies have not been carried out on how this could alter load and VAR flows. These studies will be performed when more details of the generator location and sizes are available and an assessment of the location of the new TS and the required feeders to connect the generation has been conducted.

b) See response to a).

c) Studies have not been conducted to indicate if power flows are materially affected nor even if mitigation measures are warranted.

d) Without knowing what generation characteristics are being connected to the feeders, it is not possible to know how this generation can affect the dispatch of other generators on the system.

Ontario Energy Board (Board Staff) INTERROGATORY #146 List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Ref: ExhA/Tab14/Sch2/p6

Hydro One indicates that it expects over 3,500 MW of renewable generation to be commenced by 2011. Please provide a table that shows which areas of the province will have what proportion of this load installed. How much of the 3,500 MW is to be completed in 2010?

Response

The forecast of 3,500 MW of renewable generation by 2011, which assumes technical feasibility (e.g. transmission and distribution capacity availability), is based on consideration of the four factors listed on page 8 of Hydro One Distribution's Green Energy Plan.

Hydro One does not have a detailed forecast of renewable generation connection by MW and by location but based on historical applications for distribution generation connections, Hydro One expects the following proportion of applications in different areas of the province:

- 45% in the Southwestern areas of Ontario, including southwest portions of the Golden Horseshoe
- 25% in the Eastern areas of Ontario
- 15% in the central areas which include the Georgian Bay and Muskoka areas of Ontario
- 15% in the northeast and northwest portions of Ontario, which includes those parts of the province which are north of the Muskokas

Ontario Energy Board (Board Staff) INTERROGATORY #147 List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Ref: ExhA/Tab14/Sch2/p7

Hydro One references areas of the province where connection of renewable generation is not currently feasible due to existing system constraints. Please provide an overview of the areas of the province where these constraints exist and how many of the projects representing the 3,500 MW are located in these areas of constraint.

Response

The technical constraints referred to in Exhibit A, Tab 14, Schedule 2, page 7 pertain to the ability of the distribution system to connect renewable resources. As noted in Exhibit A, Tab 14, Schedule 2, page 7, the technical constraints are the transformer station loading capability, transformer station short circuit capacity or the current carrying capability of the individual feeders connected to the transformer stations. The amount of renewable generation that can be connected at any transformer station are dependent on these technical constraints. Please refer to Exhibit H, Tab 1, Schedule 146 for an estimate of the percentage breakdown of the generation in the various areas of the Province. The percentage breakdown reflect the technical constraints described in Exhibit A, Tab 14, Schedule 2, page 7.

Ontario Energy Board (Board Staff) INTERROGATORY #148 List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

148. Ref: ExhA/Tab14/Sch2/p9

Hydro One has indicated that has identified the regions where potential for renewable energy generation is the highest. What are these regions and what proportion of the investment in the Green Energy Plan is targeted for these areas?

Response

See response at Exhibit H, Tab 1, Schedule 146.

Ontario Energy Board (Board Staff) INTERROGATORY #149 List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Ref: ExhA/Tab14/Sch2/p7

Hydro One states 3,500 MW of renewable generation is projected to be connected to its distribution system by 2011 and an additional 3,500 MW is projected to be connected by 2014.

a) Does Hydro One believe it can connect 7,000 MW of new renewable generation to its distribution system and bring it all into service by 2014? What are the major constraints that Hydro One faces in achieving this goal?

b) With respect to the 7,000 MW of new renewable generation under consideration, can Hydro One provide a projected regional breakdown of this additional new supply and also disaggregate this supply as to the transformer stations to which the new supplies will be connected.

Response

a) Yes. The budget proposed in the Green Energy Plan for 2010 to 2014 is based on a forecast of 7,000 MW. This forecast is based on the CIA applications that Hydro One received and therefore assumes projects come forward in approximately the same project distribution scenario as the CIA applications. This forecast also assumes that the necessary regional and bulk transmission upgrades are in place to allow this level of distribution connected renewables to be delivered to load centres in the province.

b) Please refer to Exhibit H, Tab 1, Schedule 146 for a percentage estimate of the generation expected in each area of the province. An approximate indication of the potential generation that might be connected to each transformer station is also available from the list of transformer stations and CIA applications at the stations provided as Attachment 1 to Exhibit H, Tab 10, Schedule 6.

Ontario Energy Board (Board Staff) INTERROGATORY #150 List 1

Interrogatory

Issue 9.2 Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?

Ref: ExhC1/Tab2/Sch1/p2 and ExhD1/Tab2 Sch1

In the OM&A and Capital Expenditure evidence Hydro One often references additional work (direct and indirect, internally funded and externally funded) required to meet the requirements of the Green Energy Act. Please provide an estimate of the total OM&A and capital budget increases for 2010 and 2011 that are a result of Green Energy Act related work. How much of each amount is planned for recovery and how much will be absorbed by Hydro One?

Response

The OM&A and Capital budgets attributed to work programs directly associated with the *Green Energy Act and Green Economy Act* (GEGEA) are described in detail in Hydro One Distribution's Green Energy Plan provided in Exhibit A, Tab14, Schedule 2. The amounts to be recovered from Hydro One customers, generators, and external funding are summarized in the table on page 1 of the Green Energy Plan.

Indirect OM&A costs related to the Green Energy Act (e.g. increase in the scope of work associated with such day-to-day activities as planning, strategy development, policies and standards, prioritizing and monitoring of work, customer care and operations) are not included in the Green Energy Plan. Hydro One expects these OM&A costs will be funded by its Distribution rates.

Ontario Energy Board (Board Staff) INTERROGATORY #151 List 1

Interrogatory

Issue 9.2 Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?

151. Ref: ExhC1/Tab2/Sch1/p2
Hydro One forecasts the revenue requirement to be collected via external funding to be $8 million in 2010 and $30.7 million in 2011. Please provide a detailed calculation of how these amounts were determined, clearly showing all assumptions used in determining these amounts.

Response

The calculation of the revenue requirement of $8M in 2010 and $30.7M in 2011 to be collected via external funding is provided below. The assumptions used to determine this revenue requirement are the same as the assumptions used to determine the revenue requirement to be collected from Hydro One Distribution's customers (e.g. capital structure, cost of capital, tax rates, etc.). The one exception is that the calculation of the depreciation amount for the assets to be funded externally is based on an assumed useful life of 20 years, consistent with the expected average length of the contracts for generators to be served by these assets.

Revenue Requirement	**2010**	**2011**
OM&A	-	-
Depreciation	3.5	12.8
Capital tax	0.1	0.0
Return on debt	2.2	8.2
Return on equity	2.2	9.0
Income tax	0.1	0.7
Total Revenue Requirement	**8.0**	**30.7**

Ontario Energy Board (Board Staff) INTERROGATORY #152 List 1

Interrogatory

Issue 9.2 Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?

Ref: ExhA/Tab14/Sch2/p1,2,16-22

Hydro One states on pages 1 and 2 that a great deal of the expansion and enabling investments required for the Hydro One system as a result of the Green Energy Act should be recovered through an external funding mechanism.

a) Given that that the expansion projects include distribution line reinforcement as well as the construction of additional circuits and that the enabling investments will include additional instrumentation and control, does Hydro One not believe that these investments will reduce losses, reduce congestion and improve operational efficiency and switching flexibility of its distribution system?

b) If Hydro One agrees that the above noted reinforcements and enhancements have economic value to the Hydro One distribution system, please propose a methodology and approach for assessing this economic value.

c) If Hydro One does not agree that the above noted reinforcements and enhancements have economic value to the Hydro One distribution system, please provide reasons and explain how Hydro One reaches that conclusion.

Response

a) Hydro One does not believe expansion and enabling investments will reduce overall system losses or system congestion. The Hydro One distribution system is mostly rural with sparse loads spread over large distances. Large amounts of generation connected to this system can result in significant reverse power flow and potentially higher losses especially with intermittent resources which may have higher output levels during off-peak periods than in on-peak periods. Also large amounts of generation are proposed in areas where there is already a surplus of generation. This will result in higher transfers on the regional and bulk transmission system and can lead to higher levels of congestion. Generation that is sited in more remote areas of the system will also result in higher losses to deliver the power from those remote areas to major load centres. The benefits to the Distribution system of Renewable Enabling Improvements (REI) and Expansions to connect renewable energy generation are discussed in Hydro One's revised Green Energy Plan (Exhibit A, Schedule 14, Tab 2) filed with the Board September 25th.

b) Hydro One's proposed Load Growth, Asset Replacement and REI-specific criteria (discussed on pages 17-19 and 21-23 of the Green Energy Plan) address what Hydro One believes to be the key benefits to the Distribution system from REI and Expansion investments related to the connection of renewable energy generation. For the reasons noted in a), Hydro One does not believe that a methodology to assess the "benefits" associated with losses, congestion or operational efficiency is appropriate.

c) See answers a) and b).

Ontario Energy Board (Board Staff) INTERROGATORY #153 List 1

Interrogatory

Issue 9.2 Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?

153. Ref: ExhA/Tab14/Sch2/p1, 27-29

Hydro One states that the total costs for Smart Grid spending are projected to be $40 million in 2010, $72 million in 2011 and $295 million in 2012-2014. Hydro One further states on pages 28 and 29 that it plans to invest in Smart Grid features such as reactive support, storage devices, Wimax, outage management and mobile workforce tools and plug in electric vehicle applications.

a) Given that at Exhibit A, Tab 14, Schedule 2, page 27 of its evidence Hydro One states that it plans to have close relationships and partnerships with a number of agencies and that several of these other agencies are carrying out their own pilots, why has Hydro One not considered concentrating on only a few Smart Grid initiatives (related to Ontario-specific challenges) and relying on the test results and pilot study results from others for the rest?

b) If the above more focused course of action were taken by Hydro One; 1) what three Smart Grid initiatives does Hydro One consider most important and/or most unique to its service area; and 2) if only those three initiatives were pursued, what are the cost savings compared to the more broadly – based approach favoured by Hydro One?

Response

a) Hydro One does intend to focus on the immediate challenges in Ontario, that being: rapid growth and integration of DG; higher penetration and targets for conservation and demand management; and as part of this, the implementation and migration of customers to time of use rates. The solutions (systems, communications, business processes, monitoring and control devices in the field) that are required to meet these challenges are also capable of supporting other business scenarios that have the potential to enhance operating effectiveness and customer service across Hydro One's vast and largely rural service territory. Because the success of Smart Grid will depend upon the integration of all components, we need to examine all potential

business scenarios and benefits to develop an integrated solution that will work for Hydro One over the longer term.

b)

1) The Smart Grid scenarios that are most tightly correlated to government direction are DG Integration and Customer Enablement (for conservation and demand management and assisting customers with managing their bills for time of use billing). Maximizing renewable energy (wind / solar / hydroelectric / biomass) is one of the leading objectives of this scenario. To this end, options to reconnect DG's, automatically transfer DG control to other feeders, or store excess DG outputs all form an integrated solution. We also need to understand what tools, devices and information our customers want and need to help them better understand and manage their electrical consumption and peak demand.

   The same solution sets required to enable the scenarios above can also be leveraged for other business benefits. Two such scenarios are Distribution Reliability and the Outage Restoration Optimization response. Distribution automation would focus on SCADA and Intelligent Electronic Device deployments on various pieces of equipment augmenting with video feeds to provide visual confirmation of station perimeter security and equipment status. Customer outage response would minimize outage duration by enhancing workforce mobilization. Outage management would require integration of various enterprise systems.

   Finally, the scenario regarding the Distribution Network Asset Planning and Tools will provide for an operational data store to capture and archive all real-time operating data gathered through the other solutions sets, and integrate it with other, existing data sources. This will effectively allow for the effective execution of other scenarios (i.e. we need to automate our Dx planning to be able to plan for the high volume of DG's and potentially DR to be connected).

2) Since various scenarios leverage previously established systems and devices, it is not possible to calculate the cost savings associated with narrowing the scope of the various Smart Grid scenarios. The incremental costs for some initiatives are expected to be lower when compared to costs to complete the initiative alone.

Ontario Energy Board (Board Staff) INTERROGATORY #154 List 1

Interrogatory

Issue 9.3 Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?

154. Ref: ExhA/Tab14/Sch2/p15 (revised)

On this page, Hydro One presents a table which shows the capital cost of connecting renewable generation, $13 million in 2010, $27 million in 2011 and $40 million from 2012 to 2014. Hydro One expects that these costs will be covered by the generators themselves. Please provide a list of these projects and what region of the province these connection activities are expected to take place.

Response

The referenced costs are only the portion of the capital costs that will be recovered from generators for investments to connect and enable new renewable generation. It is not possible to provide a list of specific projects until the FIT applications are known.

Ontario Energy Board (Board Staff) INTERROGATORY #155 List 1

Interrogatory

Issue 9.3 Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?

Ref: ExhA/Tab14/Sch2/p19 (revised)

On this page, Hydro One presents a table which shows the capital cost of the expansion of the distribution system to connect renewable generation. For 2010, 2011 and the 2012 to 2014 period, please provide a list of these projects and what region of the province these expansions are expected to take place. Please also provide the rationale for how external funding was determined for these projects on an individual, project by project, basis.

Response

Hydro One's proposed methodology to determine the work to be funded externally is discussed on pages 17-19 and 21-23 of Hydro One's Green Energy Plan (Exhibit A, Tab 2, Schedule 14). The work in the Green Energy Plan has not been identified on an individual project basis but an estimate of the percentage breakdown of the generation in the various areas of the Province is provided in the response at Exhibit H, Tab 1, Schedule 146. The amount of external funding is based on an aggregate approach to the planned Expansion and Renewable Enabling Improvement investments.

Ontario Energy Board (Board Staff) INTERROGATORY #156 List 1

Interrogatory

Issue 9.3 Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?

156. Ref: ExhA/Tab14/Sch2/p23 (revised)

On this page, Hydro One presents a table which shows the capital cost of the enabling improvements to the distribution system to connect renewable generation. For 2010, 2011 and the 2012 to 2014 period, please provide a list of these projects and what region of the province these expansions are expected to take place. Please also provide the rationale for how external funding was determined for these projects on an individual, project by project, basis.

Response

Please see the response at Exhibit H, Tab 1, Schedule 155.

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

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Ref: Exhibit A-15-2/Attachment 1, Section 2.3 "Goals & Objectives of the Benchmarking Study"/p7, 11, 12-13, 18.

The Study states in part that:

- *Comparability characteristics should be considered when choosing participants.*
- *Comparability criteria must be explicitly identified using defined measures.*
- *Comparison criteria suggested:*
  - *Percentage of lines requiring vegetation management;*
  - *Type of terrain comprising the service territory;*
  - *Differentiations between rural and urban territories;*
  - *System characteristics such as splits between on-road and off-road lines and overhead and underground lines.*

As noted at page 11, the selected Utilities include only a single Canadian Utility, BC Hydro. On pages 12-13, the selected Utilities 41 and 3 show customers per circuit kilometer above 30, and markedly different from all other utilities and Hydro One's zones. At the bottom of page 12, it is stated that utilities 41 and 3 were retained in the study "given that they substantially met the other comparability criteria". On page 18, utility 41 is indicated as having an average cycle length of one year.

a) Given the stated selection criteria please provide the reasons why other Canadian utilities' Distribution Systems were not selected/included by CN Utility Consulting Inc ("CNUC") to be part of the group, such as:

   - Hydro Quebec's Distribution System;
   - Manitoba Hydro's Distribution System;
   - NB Power's Distribution System; or
   - Saskatchewan Hydro's Distribution System.

b) Please elaborate on the comparability criteria alluded to and how utilities 41 and 3 were assessed as being comparable for inclusion. In particular, if utility 41 has an average cycle length of one year as cited on page 18, does this not suggest environmental parameters (length of growing season, precipitation, fast-growing vegetation) markedly different than that typical in Hydro One's service territory?

c) Coniferous versus deciduous tree coverage is mentioned in the study as one reason underlying greater tree removal and average lower labour hours for Hydro One compared to other sampled utilities. Given this acknowledged environmental difference which affects operational practices, please explain why the study included sampled utilities, including those in southwestern and south-central U.S. while not including Canadian utilities and other utilities in the northeastern and north central parts of the U.S. that may have more similar vegetation patterns as well as other environmental parameters (climate, geography)?

Response

a) As noted on page 10 of Exhibit A, Tab 15, Schedule 2, Attachment 1, CN Utility attempted to secure participation from approximately 60 utilities, including all 4 of the utilities referenced above, of which only 25 agreed to participate. The group of 60 included a number of Canadian utilities but the group of 25 that agreed to participate included only one Canadian utility (i.e. BC Hydro) other than Hydro One. The reasons that utilities did not want to participate ranged from concerns about regulatory implications in their home jurisdictions to not enough resources to devote to the study

b) Appendix D of Attachment 1 in Exhibit A, Tab 15, Schedule 3 elaborates on the comparability criteria. Included in those criteria are vegetation parameters such as tree density and type (discussed in Appendix D1 starting on page 45) along with weather considerations such as growing conditions (discussed in Appendix D2 beginning on page 47) and storm impacts. These criteria as described in Appendix D address environmental parameters in a direct manner as opposed to an indirect inference based on the length of a utility's cycle. Based on a direct examination of environmental parameters, CN Utility concluded that both utilities 41 and 3 are comparable to Hydro One Distribution. It should be noted that some jurisdictions, including the one that utility 41 resides in, have regulated clearance distances and do impose fines on utilities when minimum clearance distances are violated. This regulatory requirement can influence the cycle length.

c) As noted in part a and b, the study included comparable utilities from all parts of North America that agreed to participate. Although the participation from Canadian jurisdictions is minimal, the utilities do provide a fair representation of northern climates as a result of participation from utilities in British Columbia, Wisconsin, Washington, Michigan, and Maine. The comparison of coniferous and deciduous tree percentages that was noted and which can be found on page 73 in Appendix E of the report (Attachment 1 in Exhibit A, Tab 15, Schedule 3) illustrates this point. In that

comparison, 4 of the 14 comparable utilities have a greater percentage of coniferous trees than does Hydro One, which shows that the lack of Canadian companies does not diminish the validity of the peer group of utilities.

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

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Ref: Exhibit A-15-2/Attachment 1/p20

In regard to misinformation in the public domain about herbicides and their impact on the environment, Hydro One has undertaken initiatives including the one reported in the reference, where the CNUC Report states that:

- ***Launched a study and pilot on the usage of herbicides*** *- This study consists of systematic plots that have been set up to test various herbicides, application techniques, and timing alternatives. The most effective techniques and applications will be utilized in the UVM program to improve cost efficiency.*

Please provide a description of the study detailing its scope, methods, approach, phases, and timeline covering formulation and implementation, and when such a study will be available for review.

Response

Hydro One recognizes the value of selective herbicide application. The referenced herbicide study is a productivity initiative and is not related to "misinformation". (Other initiatives have been directed to addressing misinformation.) .

With regard to the effective use of herbicides, a pilot and study on a number of treatments has been initiated. The study, entitled *Distribution Brush Control Research Study* is a multi-year analysis comparing the efficacy and efficiency of a combination of cut and treat methods for various brush densities. Hydro One is looking at ways to improve the brush control program. Six treatment methods are being investigated including variations of:

- cut with no herbicide,
- cut with herbicide treatments in 1, 2, and 3 years following cutting,
- using stump and foliar application methods and two herbicide rates;
- sites with brush density of light, medium and high brush are being sampled on distribution lines where we have secured permission from property owners

The herbicide being utilized is Triclopyr and is applied at two rates: 5% and 30%. Plots along with initial treatments were established in 2009. Follow up treatments over the next three years will be scheduled and interim reports prepared to track progress at the end of each years followed by a final report at the conclusion of the study

Ontario Energy Board (Board Staff) INTERROGATORY #3 List 2)

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Ref: Exhibit A-15-2/Attachment 1/p21-22

The chart on page 21 indicates that Hydro One spends, on average, fewer labour hours per tree than the sample while chart 22 indicates that the average cost per tree is materially higher than the peer group.

Given that Hydro One's average cycle, at 10 years, is longer than that of most other utilities in the sample group (ranging from 1 to 5 years), it would be expected that more clearing would be required per tree and hence that it would take as long or longer than for peer group utilities. Given that labour hours are shorter, while costs are higher, does this indicate that there may be differences between Hydro One's operating environment or operational practices that make it different from sampled utilities? Please explain.

Response

The discrepancy identified between labour hour and cost measures is a result of various factors that distinguish Hydro One Distribution from many of the peer utilities in the study.

One major factor that was discussed in the study is that Hydro One Distribution is operating in the most rural service territory of all utilities as illustrated in Figure R4 of page 13 of Attachment 1 in Exhibit A, Tab 15, Schedule 2. To conduct maintenance in such a territory, field crews must travel long distances and routinely establish temporary work headquarters. These activities result in additional costs for travel and meal allowances, along with room and board. These costs would be included in Hydro One Distribution's cost per tree value.

The study also referred to a number of other factors that have the potential to impact cost but not labour hours. These factors cover a broad range of influences and include:

- Hydro One places a great emphasis on safety and training and as a result, overhead costs associated with developing training materials and maintaining training resources are included as part of vegetation management costs. This factor is noted on page 20 of the study with reference to cost per kilometre and is equally applicable to cost per tree.
- Potential differences in cost structure associated with contracting or union arrangements will impact costs as noted on page 17 of the study. Hydro One

Distribution includes all costs in the cost per tree value where other utilities may account for activities such as contract management separately.

- Costs denominated in Canadian dollars during the 2006 to 2008 period would be at a disadvantage relative to those denominated in US dollars as a result of the dramatic appreciation of the Canadian dollar as noted on page 14 of the study. The value of the Canadian dollar during the 2006 to 2008 period was approximately 20% greater than it was for much of the previous decade.

The various factors that influence costs beyond labour hours distinguish Hydro One Distribution's operating environment and practices from those of the peer utilities. Furthermore, it is important to note that CN Utility on page 17 stated that the labour hours per kilometre measure is a more reliable efficiency measure than cost per kilometre given the presence of the aforementioned factors.

Ontario Energy Board (Board Staff) INTERROGATORY #4 List 2

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Ref: Exhibit A-15-2/Attachment 1, Section 4.2.4 Reliability", pages 33-35 and Conclusion, pages 36 – 37

The study, in regard to its finding on "Reliability" indicated in Section 4.2.4, indicated that:

- Most utilities report that after safety, the number one reason for operating a UVM program is to ensure reliable electric service to customers.
- Hydro One's system is very vulnerable to storm activity as is evidenced by the high storm impact on reliability.
- Given Hydro One's lengthy cycle in comparison to the peer group, these findings are not unexpected and utilities with shorter cycles will naturally perform better.

The study's concluding remarks on page 37, indicated that:

- To further improve efficiency, Hydro One needs to reduce its UVM cycle, as it is apparent, through comparisons with peer companies, that Hydro One's cycle is significantly longer than peer utilities and that more frequent treatments will allow Hydro One to get closer to the mainstream of good utility practice.
- Shorter cycles will reduce costs on a per kilometre basis as less biomass will need to be removed, will improve the control of vegetation and thereby reduce the need for unplanned UVM activity, and will improve the reliability of Hydro One's distribution system.

a) Given the CNUC report's finding in section 4.2.4, please advise if Hydro One performed analysis with regard to the impact of its distribution system unreliability on costs to its distribution customers. If "Yes", please provide this analysis.

b) If the answer to a) above is "No", please indicate whether or not such a study can be performed? If "Yes", how long would it take to complete such a study and file it with the Board if so directed?

c) Does Hydro One intend to implement the findings of the CNUC Report? If so please provide a plan identifying the areas that Hydro One intended to implement absent this study and the additional areas it intended to incorporate in its existing plan along with an implementation timeline.

Response

a) No, Hydro One Distribution has not assessed the impact of system unreliability on costs to its Distribution customers. It should be noted however that according to the *Cost of Reliability* CEATI report, the costs can be significant depending on the model used. Hydro One cannot provide definitive societal financial benefits, but it is believed that the reduction in outages in moving to a 7 year cycle would be significant and could range anywhere from $10s of millions of dollars to over a $100 million.

b) A study to quantify customer costs associated with system unreliability could be undertaken. Hydro One would need to review industry studies on this topic and if a methodology suitable to Hydro One is not available, one would have to be developed. Any methodology will require a significant amount of customer specific data to allow for precise calculations related to loss and damage associated with power outages. At best, such data will be time consuming to extract from existing systems and databases, and at worst may not be available at all. It would also be desirable to have other members of the industry review and comment on the findings in order to present a more complete perspective on the topic. Given the issues noted above, Hydro One estimates that the time needed to complete such a study would be well over a year.

c) The CN Utility study focused on efficiency comparisons and in the process of doing so also produced findings in regard to cycle lengths. Hydro One Distribution's vegetation management plans prior to the study were to increase maintenance and achieve a 7-year cycle accomplishment in 2011. The findings in the study support reducing the cycle length and conclude that a shorter cycle will result in increased efficiency and improved reliability. This is an affirmation of Hydro One Distribution's existing plans.

Despite recommending a shorter cycle, the study does not go as far as recommending a target cycle and in the absence of such a recommendation, Hydro One Distribution has decided to continue along the path of reducing the cycle as decided upon prior to the study. The plan will continue to increase accomplishments using a managed and methodical approach and will continue to assess the benefits of a shorter cycle during the transition phase.

Ontario Energy Board (Board Staff) INTERROGATORY #5 List 2

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Ref: Exhibit A-15-2/Attachment 1

In Hydro One's 2008 Cost of Service distribution rate application (EB-2007-0681), Hydro One filed an external Benchmarking study conducted by PA Consulting Inc. as well as an internal study *2008 Vegetation Management Program Review*, Exhibit H/Tab1/Schedule14/Attachment C on the Hydro One's vegetation management. Hydro One's vegetation management, including the longer-than average cycle length and the relationship between costs and cycle length, were highlighted in these studies. There was extensive testing of the evidence of these studies on the record in the previous application. In its Decision with Reasons, the Board stated:

> "Moving to an eight-year cycle is expected to result in improved reliability for the Company's customers.
>
> The Board considers the increased spending associated with this program to be of a nature that brings it outside of a simple application of historic norms driving spending approvals. While the cost is somewhat high, this innovation appears to be justified." [p. 12]

Hydro One indicated its intention to move towards a seven-year average cycle length, while the external and internal studies indicated that a five year cycle length may be closer to "good utility practice" based on comparative utilities and on long run operational efficiencies.

a) Please indicate whether Hydro One believes that the CN Utility Consulting Study filed in this application corroborates the analysis and findings of the earlier studies that a five year average cycle length would seem to be desirable based on good utility practice, cost efficiency and customer reliability. Please explain your position.
b) In the previous application, Hydro One indicated that it was moving from its current average cycle of 10-11 years towards an average cycle length of 8 years, and the Board approved Hydro One's proposed expenses for vegetation management.
    i) As Hydro One's current evidence (Exh C1/Tab2/Sch2/p34) indicates that it is moving to a 7 year cycle by 2011, what are the additional costs of moving to a 5 year cycle, based on its current operations plan and budget?

ii) Has Hydro One considered the merits of a longer cycle for territory in the North, as it has a shorter growing season? If not, why not?

Response

a) Earlier studies and in particular the 2008 Vegetation Management Program Review submitted as part of Hydro One Distribution's last rate application (i.e. EB-2007-0681) concluded that a desirable cycle is in the 6 to 7 year range. The study confirmed that shorter cycles do result in improved reliability but that very short cycles are not cost effective.

The most recent benchmarking study completed by CN Utility found that comparable utilities operate on cycles that were 5 years or less. A 5-year cycle is beyond the 6 to 7 year range that had previously been identified as desirable but is very close. As such, Hydro One Distribution will continue to reduce its cycle and as it achieves its current target of a 7-year cycle accomplishment in 2011, it will continue to assess the benefits of further reducing the cycle.

b)

i) As noted in (a), a 5-year cycle is outside of the previously identified desirable range (i.e. 6 to 7 years) and as such, Hydro One Distribution has not estimated the costs for implementing such a cycle in the 2010 and 2011 period.

ii) Yes, Hydro One has considered the merits of a longer cycle in the north and in fact does schedule maintenance less frequently for the north, as noted on line 6-8, Page 33 in Exhibit C1, Tab 2, Schedule 2.

Ontario Energy Board (Board Staff) INTERROGATORY #6 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit A/Tab14/Sch2/p3

Hydro One notes *"Smart Grid investments are assumed to be fully funded by Hydro One Distribution's customers as they will provide significant benefits to Hydro One Distribution's customers."* The manner in which this is stated seems to imply Hydro One believes Smart Grid investments can be recovered through the provincial recovery mechanism, in whole or in part, but has opted not to request such recovery. Board staff's understanding of Regulation 330/09 is that none of these investments are eligible for external funding. Does Hydro One's understanding or interpretation of Regulation 330/09 differ from Board staff's? If so, please explain.

Response

Hydro One's understanding of Regulation 330/09 does not differ from Board staff's. The quoted statement was not intended to imply that Smart Grid investments could be recovered through the provincial recovery mechanism.

Ontario Energy Board (Board Staff) INTERROGATORY #7 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit A/Tab14/Sch2/p17

In discussing the criteria proposed for assessing the benefits that Expansion work will provide to Hydro One Distribution customers, "Asset Replacement" is discussed as one criterion. Asset 'age' appears to be the only factor that is taken into account. Does Hydro One believe asset 'condition' is also an important factor in determining when a distribution asset should be replaced? If so, please explain why asset 'condition' has not been taken into account. If not, please explain why asset condition is not appropriate indicator of the expected useful life of an asset and, in turn, the benefit to Hydro One ratepayers.

Response

Asset condition is also important, however, based on Hydro One's experience and the average age of its pole assets, Hydro One expects that the vast majority of the affected poles will be replaced prematurely and as such will be in good condition.

Ontario Energy Board (Board Staff) INTERROGATORY #8 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit A/Tab14/Sch2/p18

In discussing the Load Growth criterion, Hydro One notes an assumed 1% load growth (net of CDM) per year has been used. Is 1% (net of CDM) the load growth in each of the areas of Hydro One's territory where new renewable generation will be connected in the test years? If not, what is the basis for using 1% (net of CDM) and why did Hydro One not use the load growth in the specific area of each applicable asset in the application for which external funding is being requested given this criterion is being proposed by Hydro One to be used to estimate an appropriate amount for which the Board would approve recovery from all Ontario consumers?

Response

The 1% growth rate was an assumed long term growth rate for the purpose of determining the Load Growth criterion. Hydro One does not have growth rates for individual feeders that could potentially be impacted by the connection of new renewable generation. The purpose of the calculation was to estimate the number of feeders that will reach their capacity over the next 20 years due to normal load growth.

Ontario Energy Board (Board Staff) INTERROGATORY #9 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit A/Tab14/Sch2/p19

Further to the Load Growth criterion, Hydro One goes on to note "*It was also assumed that the planned generation-driven Expansion projects would provide a benefit for only 20% of the investments required in areas experiencing load growth.*" Please explain how Hydro One determined 20% to be an appropriate assumption.

Response

It is impossible to determine exactly how loads will grow across the province over a 20 year time frame, or at this point in time determine the impact of the FIT program on feeders supplying those loads. 20% is Hydro One distribution's best estimate of what might happen.

Ontario Energy Board (Board Staff) INTERROGATORY #10 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit A/Tab14/Sch2/p19

Hydro One has estimated the benefits to Hydro One customers to be relatively minor in allocating about 83% of the gross Expansion related costs to the provincial recovery mechanism (i.e., "external funding").

a) Is it therefore Hydro One's intent that only renewable generators will be connected to such new assets going forward (i.e., no new load customers and no new non-renewable generation will be connected)?
b) Does the same apply to existing assets that are being upgraded and currently serve only existing load customers?
c) If not, please explain in detail how Hydro One is taking existing vs future load customers into account in determining to what extent Hydro One ratepayers will benefit and therefore should be allocated a portion of the costs. Please use a specific applicable capital investment in Exhibit D2/Tab2/Schedule3, specifically D28, as the foundation for the explanation associated with allocation of the Hydro One's portion of the costs between Hydro One's existing and future load customers.

Response

a) In general, renewable generators do not site themselves in areas that are heavily populated nor are likely to be heavily populated. Therefore, it is expected that expansions will provide little benefit to Hydro One Distribution customers.

   In the past, there have been renewable generator projects that applied to Hydro One for connection and they have been sited very close to each other, however these have often been projects owned by the same proponent. Therefore, it is not expected that independently owned renewable generator projects will site so close that they will be able to connect to the new assets built previously as Expansions.

b) Yes.

c) See response to b) above.

Ontario Energy Board (Board Staff) INTERROGATORY #11 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit A/Tab14/Sch2/p22

Hydro One proposes that the SCADA portion of the investment be *"shared equally for the 30% of DSs impacted … resulting in an estimated benefit to Hydro One Distribution customers of 9%"* and, thus, 9% of the investment cost be recovered through Hydro One Distribution rates, with the balance being recovered via an external funding mechanism. Please elaborate on how 9% vs 91% was determined by Hydro One to result in the cost being "shared equally".

Response

The 9% allocation is calculated as follows:

1. Three fifths (60%) of the cost of the SCADA required for enabling generation is for those components of the investment required just for distribution station monitoring. The balance of the investment is for changing the station (DS) reclosers, which is wholly driven by enabling generation.
2. Of the stations targeted for SCADA to enable generations, about 30% are stations that were also targeted for enhanced DS monitoring.
3. The cost of the SCADA investments required just for distribution station monitoring are assumed to be shared equally (i.e. 50% each) between load customers and renewable generation.

Accordingly, the share of the costs to be recovered through Hydro One Distribution rates is calculated as 60% x 30% x 50% = 9%.

Ontario Energy Board (Board Staff) INTERROGATORY #12 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit A/Tab14/Sch2/p17-22

On page 21, Hydro One it discusses how Renewable Enabling Investments dovetail with development of the Smart Grid. On page 28, in discussing the Smart Grid, Hydro One discusses rolling out enablers (i.e., Wimax) to facilitate the connection of renewable generation. What criteria is used by Hydro One to determine if a certain capital investment has been identified in the application as a Smart Grid investment or a Renewable Enabling investment?

Response

Renewable Enabling Investments are capital investments associated with connecting new renewable energy generation to the distribution system and include the types of investments described on page 20 of its Green Energy Plan (Exhibit A, Tab 14, Schedule 2).

Smart Grid investments are capital work completed under the Smart Grid program to evolve Hydro One Distribution's system into a "smarter", more automated, distribution system that will enhance the reliability, security and power quality for all of Hydro One's customers. As noted on page 25 of its Green Energy Plan, while this will help enable renewable generation, it also allows for new conservation and demand management programs through innovative two communications, and it will improve asset condition monitoring and trouble call responses with more accurate data and enhanced system control.

Ontario Energy Board (Board Staff) INTERROGATORY #13 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit D1/Tab3/Sch3/p11

Is it Hydro One's expectation that the trend in Table 3, will continue over the long term (i.e., relatively immaterial amount of small generator connections compared to large and mid-size)?

Response

As we now know more about the proposed Distribution System Code amendments on cost allocation for generation connections, an increased number of small generator connections is expected compared to historical numbers of small generator connections, once the FIT program launches. However, it is difficult to predict the amount by which the number of small generator connections will increase compared to large and mid-size generator connections.

Ontario Energy Board (Board Staff) INTERROGATORY #14 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit D1/Tab3/Sch3/p14

In the application (prior to the update), Hydro One explained that the benefits to Hydro One ratepayers differ quite substantially based on the size of the connecting generators. For example, it stated on page 14 that the benefit to Hydro One load customers was estimated to be about 15% of the cost for connection of generators in the large (>10MW) and mid-size (500kW to 10MW) categories and 30% of the cost for small (<500kW) generator connections. This appears to have been removed in the evidence update.

Was this reference removed because Hydro One determined it was not accurate? If it remains an accurate characterization, can Hydro One please broaden that explanation to clarify why there is approximately the same benefit allocation for mid-size and large generator connections and differs quite substantially when it involves connecting small generators?

Response

The percentages used in the evidence filed on July 13, 2009 were largely based on a limited number of historical generation connections, and the existing DSC requirements at the time. Since the evidence was first filed more information regarding cost responsibility and recovery has become available, including the revised DSC amendments issued by the Board on September 11, 2009 and the requirements of OReg 330/09, which came into effect on September 9, 2009.

Subsequently Hydro One determined that the assumptions used to determine the percentages quoted in the reference are no longer suitable. A new methodology was developed to consistently and appropriately allocate the benefits to Hydro One ratepayers in accordance with all the latest codes and regulation developments. The revised methodology is described in Section 3.3 of the update to Exhibit A, Tab 14, Schedule 2, filed on September 25, 2009.

Ontario Energy Board (Board Staff) INTERROGATORY #15 List 2

Interrogatory

Issue 9.5 What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?

Ref: Exhibit D2/Tab2/Sch3/Reference:D32

This investment relates to modifications to the wholesale metering system assets at 14 *"Transmission Stations"*. Hydro One notes on page 20 of Exhibit A, Tab14, Schedule 2 that *"Renewable Enabling Improvements ("REI") address modifications or additions to the main distribution system*". In addition, in the Board's June 5th , 2009 Notice in relation to EB-2009- 077, it states *"Some generation connections may trigger the need for upstream upgrades to the system of a … transmitter….Although the DSC is silent on the issue of cost responsibility for these upstream upgrades, the practice is for distributors to pass these costs on to the connecting generator. The Board does not propose to revise this approach at this time".*

Please explain why Hydro One believes this investment constitutes a modification to the main distribution system, how is it consistent with the definition of an "eligible investment" in Regulation 330/09 and why it is appropriate to request recovery from ratepayers in a distribution rate application.

Response

Although the Hydro One wholesale revenue meters are located at Transmission Stations, they are a distribution asset funded by Hydro One's LDC customers. For this reason, these costs are presented in the distribution rate application.

This investment is required to address revenue metering issues that arise solely as a result of generation connecting to the Hydro One distribution system. Hydro One believes that revenue metering changes represent a renewable enabling improvement, under the OEB's definition in its September 11, 2009 Notice of Proposed Amendments to the DSC which states a *"renewable enabling improvement" means a modification or addition to the main distribution system identified in section 3.3.2 that is made to enable the main distribution system to accommodate generation from renewable energy generation facilities.* Further, Hydro One feels that the subject revenue metering changes are not connection facilities or expansions, definitions for which are also referred to in that Notice.

Therefore, Hydro One recommends that the cost of this investment be allocated to all electricity customers in the Province and recovered via an external funding mechanism.

Green Energy Coalition (GEC) INTERROGATORY #1 List 1

Interrogatory

1. Re: Ex.A, Tab 14, Sched. 2, p. 7, l. 6

The data provided in tabular form indicates that approximately 45% of proposed projects under the RESOP did not proceed to full CIAs as they were "outside threshold".

a. Please discuss the impact that expected investments in "renewable enabling improvements" and "expansions" at both the transmission and distribution level will have upon this constraint.

b. What are HONI's projections for the level of CIA requests, threshold rejections, CIA completions, cost estimate completions and connection cost recovery agreements completed (or in each case the analogous step under the new DSC and FIT rules) for 2009 (full year), 2010, and 2011?

c. What are the prospects for expansion of the 'green zone' in the coming periods and how might this affect the work plan and budget?

Response

a) The "expansions" and "renewable enabling improvements" definitions as described in the DSC pertain to the distribution system. Expansions and renewable enabling improvement may result in more projects that may fall inside the "threshold" if they increase the technical limits described on page 7 at Exhibit A, Tab1, Schedule 2. For example, if the constraint factor at a transformer station is the feeder current capability limit but a new feeder can be expanded at the station, then more projects could be connected to the station. In another case if the constraining factor is the 60% transformer station threshold then the expansions and improvements may not result in a higher threshold. The thresholds and the constraining technical factor will vary from station to station. The amount and number of additional projects that may be connected at each station will also vary and depend on the project location, size and type. Until projects are identified by the FIT program, the impact of expansions and improvements on the threshold at the transformer stations, individually and collectively, cannot be determined.

b) The number of CIA applications is expected to remain relatively flat compared to the values shown in the table on page 7 of Hydro One's Green Energy Plan until the new FIT rules are established. While an increase in the number of applications is expected, it is uncertain how the finalized rules of the FIT program will affect the level of applications. It is difficult to project cost estimate completions and

connection cost recovery agreement completions, as initiation and completion of these agreements depends on the customers.

c) The Orange and Yellow Zones, as designated by the Ontario Power Authority, are restricted zones for OPA contracts due to transmission constraints. Therefore, depending on the projected transmission work and the required approvals, these Orange and Yellow Zones may become Green Zones, thus allowing more projects to move towards a successful contract with the OPA.

Green Energy Coalition (GEC) INTERROGATORY #2 List 1

Interrogatory

Re: Ex.A, Tab 14, Sched. 2, p. 8, l. 19

HONI states that:
...connection requests that are in excess of existing available system capacity will be assessed with respect to whether they can be enabled with economic additions to wires facilities. The OPA will do this assessment for transmission, Hydro One Distribution and other LDC's will do the assessment of distribution enabling investments. In both cases, the assessments will be guided by the Board's direction with respect to cost allocation and the degree of risk that expected generation projects will not proceed.

a. Please elaborate on what costs and benefits will be included in such assessments of economics.

b. Please illustrate how the risk of projects not proceeding will be evaluated.

Response

a) The costs and benefits will be assessed to determine if they fall within the guidelines provided by the Board for Expansion investments. Consistent with the proposed Distribution System Code amendments on cost allocation for generation connections, Hydro One's intends to cover up to $90,000/MW for Expansion costs needed for generator connections. Hydro One will seek cost-efficient REI investments on its system, consistent with DSC amendments and principles, to benefit as much generation as possible.

b) The projects that require greater than $90,000/MW in Expansions costs, or additional facilities that do not fall within the guidelines provided by the Board as REI investments will be assessed as having too much risk and therefore will not proceed unless the shortfall is funded by the interested proponents.

Green Energy Coalition (GEC) INTERROGATORY #3 List 1

Interrogatory

Re: Ex.A, Tab 14, Sched. 2, p. 4, l. 13 & p. 26, l. 27

HONI notes that its distribution plan will be updated to reflect the CDM programs associated with the forthcoming CDM targets and that the assembled portfolio will be available for the Board's review and approval by the end of 2009.

a. Please explain what aspects of the distribution plan will be updated and what costs or inputs to rate setting (as opposed to externally recouped costs) might be affected.

b. Please indicate what process HONI anticipates for any consultation, review and approval of the expanded plan.

c. Are CDM research costs such as those incurred in developing plan targets and other CDM related costs that are not program-specific included in rates or are they fully recovered through the OPA (please provide details)?

d. In keeping with the government's policy of having leading CDM goals, has HONI reviewed the experience in leading jurisdictions? If so please provide the information gathered and any analysis of that information.

e. Please provide any research and reports on the setting of suitable targets that HONI has assembled to assist in the setting of a target under the GEA.

f. Has HONI been asked to propose a target? If so, what has HONI proposed, how has that goal been developed, and how does it compare to that assumed in the load forecast?

g. What level of CDM program impact is assumed in the load forecast and what is the potential impact on revenues if the enhanced CDM program is delayed or accelerated by 6 months or one year?

Response

a. Hydro One's Green Energy Plan will be updated to reflect any targets assigned, any portfolio requirements established and any additional CDM programs. It was anticipated that targets and portfolio requirements would have been in place by June 2009 and that a portfolio of CDM programs meeting those requirements would have been developed by year end 2009 and reflected in an updated Green Energy Plan. Targets have not yet been assigned and portfolio requirements have not yet been established and as such a portfolio of CDM programs for Board review and approval are not anticipated until 2010. Since these CDM programs are expected to be funded by Global Adjustment rather than distribution rates, there is no anticipated affect on distribution rates.

b. HONI anticipates that when the Board establishes CDM targets and portfolio criteria, the Board will also establish a process for any consultation, review and approval of the CDM portfolio.

c. CDM research costs such as those incurred in developing plan targets and other CDM related costs that are not program-specific are included in rates.

d. HONI has engaged a Consultant to propose a portfolio of programs suitable for Hydro One's service territory and the customer end uses within it. This includes a review of programs from other jurisdictions with CDM programs relevant to the end uses in HONI's service territory. The consultant report is expected before the end of 2009.

e. HONI believes that realistic CDM targets should be based on customer end use load potential. HONI understands that the OPA is currently undertaking an initiative to determine the end use potential for Ontario and for individual distribution territories. HONI has provided input to both the EDA and the OPA on potential methodologies for allocating a provincial target, until such time as the end use potential analysis has been completed.

f. HONI has not been asked to propose a target.

g. The CDM impact used in the load forecast submitted in this rate application is presented in Table 2, page 8 of Exhibit A, Tab 14, Schedule 4. The CDM impact Used is consistent with the IPSP filed by the OPA with the Board on August 29, 2007. Accelerated or delayed CDM due to GEA will have a revenue impact of about $2 million for every 100 GWh of CDM impact for a full year or about half the amount for 6 months.

Energy Probe INTERROGATORY #1 List 1

Interrogatory

Issue 1.2 – Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Ref: Exhibit A, Tab 14, Schedule 3, Tables 1 & 2

a) Does Hydro One have a more recent forecast than the December, 2008 Global Insight forecast?

b) If yes, please update Tables 1 & 2 to reflect the most recent Global Insight forecast available.

c) Based on the most recent forecasts, does Hydro One believe any adjustments should be made to its forecasts of costs? Please explain fully.

Response

a) Yes, Hydro One has more recent forecast from Global Insight.

b) Table 1 and Table 2 are updated below for 2008-2011.

Table 1

	Historic			Bridge	Test	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
Distribution Cost Escalation for Construction (%)	7.9	3.7	9.2	0.9	-0.1	1.4
Distribution Cost Escalation for Operations & Maintenance (%)	6.5	3.5	7.6	-2.3	0.1	2.3

Table 2

	Historic			Bridge	Test	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**
CPI – Ontario (%)	1.8	1.5	2.3	0.9	1.7	2.0

Source: Table 1 is based on forecast released by Global Insight in August 2009. Table 2 is based on forecast released by Global Insight in June 2009.

c) Hydro One is not planning on updating its 2010/11 Distribution rate filing for changes in planning assumptions other than for cost of capital as noted in Exhibit A, Tab 3, Schedule 1, pages 2 and 3. 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.

Energy Probe INTERROGATORY #2 List 1

Interrogatory

Issue 1.2 – Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Ref: Exhibit A, Tab 14, Schedule 3, Table 4

The evidence indicates that Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for April, 2009 obtained from the Company's MTN dealer group for each planned issuance term.

Please update Hydro One's credit spreads over the Government of Canada bonds using September, 2009 information

Response

Please refer to Exhibit H, Tab 3, Schedule 27.

Energy Probe INTERROGATORY #3 List 1

Interrogatory

Issue 1.2 – Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Ref: Exhibit A, Tab 14, Schedule 3, Table 6

a) Please confirm that the CWIP rate as calculated by the Board for the 4th quarter of 2009 is 4.66%.

b) Please update Table 6 to reflect the September 2009 Consensus Forecasts and the average September 2009 spread between the average actual 10-year Government of Canada bond yield and the average DEX Mid Term Corporate Bond Index – Yield inferred from the graph on www.pcbond.com.

c) What is the impact of the revised figures calculated in (b) above on the revenue requirement in 2010 and 2011? Please explain.

Response

a) Confirmed

b) The forecasts for 2009 and 2010 in Table 6 below has been updated to reflect the September 2009 Consensus Forecasts and the average September 2009 spread between the average actual 10-year Government of Canada bond yield and the average DEX Mid Term Corporate Bond Index – Yield inferred from the graph on www.pcbond.com.

The forecast for 2011 in Table 6 below reflects the long term April 2009 Consensus Forecasts (which is provided semi-annually in April and October) and has been updated for the average September 2009 spread between the average actual 10-year Government of Canada bond yield and the average DEX Mid Term Corporate Bond Index – Yield inferred from the graph on www.pcbond.com.

Table 6

	Bridge	Test	
	2009	**2010**	**2011**
10-year Government of Canada %	3.60	3.90	4.40
All Corporate Mid-Term Bond Spread	1.33	1.33	1.33
CWIP Account Rate %	4.93	5.23	5.73

c) The impact of the revised figures calculated in Table 6 will lower revenue requirement in 2010 by approximately $0.3M and 2011 by approximately $1.1M. This reflects the lower CWIP account rates that would lower capital expenditures, in-service additions and depreciation. The resulting changes to the test year rate base are decreases of approximately $2.2M in 2010 and $6.9M in 2011.

Energy Probe INTERROGATORY #4 List 1

Interrogatory

Issue 1.2 – Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Ref: Exhibit A, Tab 14, Schedule 3, Table 6 &
Exhibit A, Tab 14, Schedule 1, Appendix A, pages 1 & 2

Please explain the difference between the CWIP account rates shown in Exhibit A, Tab 14, Schedule 3, Table 6 of 6.10%, 6.40% and 7.70% for 2009, 2010 and 2011, respectively, with the figures of 6.93%, 7.58% and 7.98% shown in Exhibit A, Tab 14, Schedule 1, Appendix A as interest capitalized rates for 2009, 2010 and 2011.

Response

The CWIP rates shown in Exhibit A, Tab 14, Schedule 1, Appendix A of 6.93%, 7.58% and 7.98% for 2009, 2010 and 2011 respectively, are the rates that were used in the Hydro One planning process that commenced in December of 2008.

The CWIP rates shown in Exhibit A, Tab 14, Schedule 3, Table 6 of 6.10%, 6.40% and 7.70% for 2009, 2010 and 2011 respectively, are based on the April 2009 Consensus Forecast consistent with the assumption used for the Hydro One bond interest rate forecast.

Energy Probe INTERROGATORY #5 List 1

Interrogatory

Issue 1.2 – Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Ref: Exhibit A, Tab 14, Schedule 3, Table 7

a) Please confirm that the provincial tax rate shown for 2010 should be 13.0% and for 2011 should be 11.75%.

b) Please confirm that Hydro One has used the rates shown in part (a) for the calculation of income taxes in 2010 and 2011.

Response

a) Hydro One confirms that rates for 2010 and 2011 are as indicated above

b) Hydro One confirms that these rates have been used in the 2010 and 2011 revenue requirement; see Exhibit C2, Tab 6, Schedule 1 Attachment A, page 1, line 24.

Energy Probe INTERROGATORY #6 List 1

Interrogatory

Issue 1.2 – Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Ref: Exhibit A, Tab 14, Schedule 3, page 7 &
Exhibit A, Tab 14, Schedule 1, Appendix A, page 3

a) What is the impact on the revenue requirement in each of 2010 and 2011 if the Management Compensation Plan annual increase is reduced from 3.0% to 2.5%?

b) Please provide the annual MCP increase for each of 2006, 2007, 2008 and 2009.

Response

a) As a result of its integrated Transmission and Distribution workforce, separate workforce compensation data for Hydro One's Distribution Business is not available. As a result, it is not possible to determine the impact upon the proposed 2011 and 2012 Distribution Revenue Requirement of a reduction in the economic increases for staff. This integrated workforce allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations.

b) Average MCP base increases were:

2006 3.4%
2007 3.3%
2008 3.8%
2009 1.5% (MCP staff either received 1.5% or no increase)

Energy Probe INTERROGATORY #7 List 1

Interrogatory

Issue 2.1 – Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A, Tab 14, Schedule 4, Table 2

a) How has Hydro One reflected that some of the cumulative CDM impact shown in Table 2 for Hydro One Retail customers may be related to some commercial and/or industrial customers that have closed and no longer have any load?

b) How has Hydro One reflected that some of the cumulative CDM impact shown in Table 2 for Embedded Direct and LDC Customers may be related to some commercial and/or industrial customers that have closed and no longer have any load?

Response

a) & b) Hydro One Distribution is using a net load impact approach to assess the CDM impacts. Please refer to Exhibit H, Tab 12, Schedule 2.

Hydro One Distribution is taking a conservative approach in accounting for CDM impacts and CDM results achieved to date show that the impact of CDM savings on Hydro One Distribution has exceeded the CDM forecast.

Energy Probe INTERROGATORY #8 List 1

Interrogatory

Issue 2.1 – Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

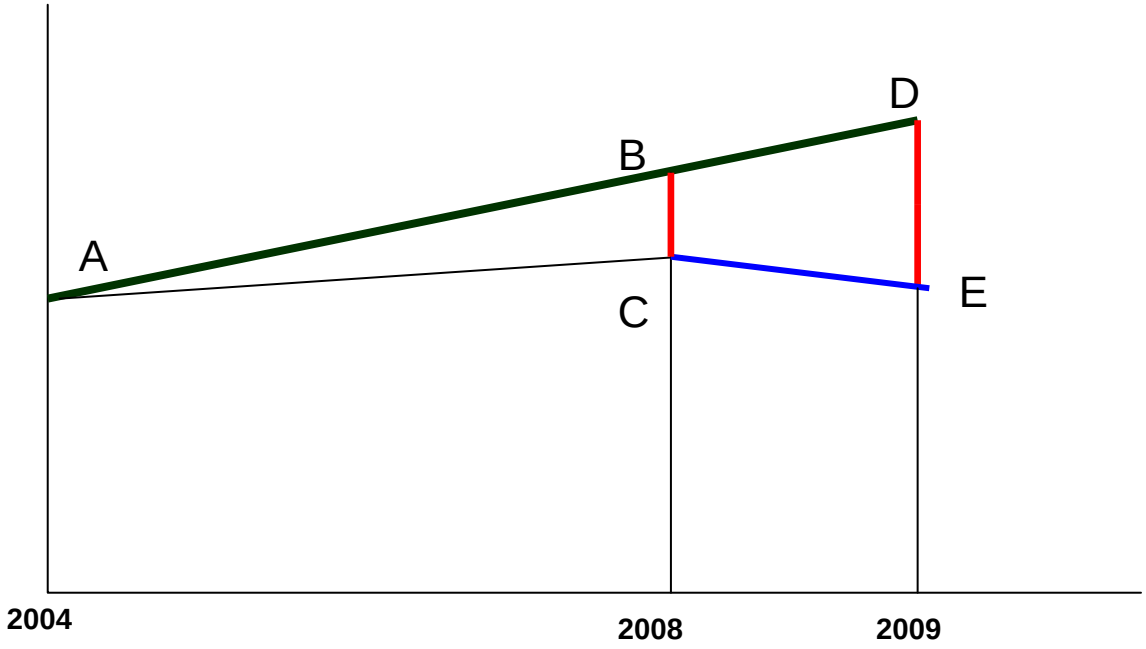
Ref: Exhibit A, Tab 14, Schedule 4, page 14

a) Does the distribution load data used in the monthly econometric and annual econometric models reflect the historical impacts of CDM? In other words, has the actual load data been weather corrected and increased by the estimated reduction due to CDM? If not, please explain why the cumulative CDM reduction is used to reduce the forecast if the load data used already includes an impact of CDM historically.

b) Given that the end-use model can explicitly reflect the unit energy consumption per end use, why is it necessary to make a further adjustment to the forecast for CDM?

Response

a) Yes. As stated in lines 4-5, page 14 of Exhibit A, tab 14, Schedule 4, historical load impacts of CDM were added back to the weather corrected actual during the modeling process. The following graph illustrates how historical CDM is added back to the actual.



A: 2004 Actual
C: 2008 Actual
B=C+BC
BC=cumulative CDM impact achieved in 2008
D: Load forecast for 2009 assuming no CDM impact
DE: Cumulative CDM forecast for 2009
E: Load forecast after deducting CDM forecast for 2009

b) The unit energy consumption per end-use in Hydro One Distribution's end-use model uses the efficiency level in 2004 as the reference baseline and assumes no efficiency improvements after 2004. Adjustment therefore is required to account for CDM impact after 2004.

Energy Probe INTERROGATORY #9 List 1

Interrogatory

Issue 2.1 – Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit A, Tab 14, Schedule 4, Table 4

a) Please provide the forecasts, in a format similar to Table 4, for each of the individual top-down (econometric) and bottom-up (end-use) models used by Hydro One.

b) What weighting factor does Hydro One apply to each of the models used to arrive at the forecast figures shown Table 4?

Response

a) The requested information similar to Table 4 in Exhibit A, Tab 14, Schedule 4 for annual econometric model forecast and monthly econometric forecast is presented in Tables 4a and 4b, respectively, followed by end-use model forecast in Table 4c. For embedded customers, only one forecast is produced and is included in all tables.

Table 4a

Annual Econometric Load Forecast Before and After CDM Impact
(GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2006	23,115	17,839	40,955
2007	23,278	17,808	41,085
2008	23,277	17,531	40,808
2009 (Bridge)	23,423	17,255	40,678
2010	23,326	17,334	40,660
2011	23,448	17,447	40,895
Load Impact of CDM			
2006	194	151	345
2007	311	245	557
2008	432	340	771
2009 (Bridge)	601	471	1,072
2010	1,325	1,035	2,360
2011	1,604	1,249	2,853
Load Forecast After Deducting Impact of CDM			
2006	22,921	17,688	40,609
2007	22,966	17,562	40,529
2008	22,845	17,191	40,036
2009 (Bridge)	22,822	16,784	39,606
2010	22,000	16,300	38,300
2011	21,844	16,198	38,043

Note. All figures are weather-normal.

Table 4b

Monthly Econometric Load Forecast Before and After CDM Impact
(GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2006	23,115	17,839	40,955
2007	23,278	17,808	41,085
2008	23,277	17,531	40,808
2009 (Bridge)	23,230	17,255	40,485
2010	23,332	17,334	40,667
2011	n.a.	17,447	n.a.
Load Impact of CDM			
2006	194	151	345
2007	311	245	557
2008	432	340	771
2009 (Bridge)	601	471	1,072
2010	1,325	1,035	2,360
2011	1,604	1,249	2,853
Load Forecast After Deducting Impact of CDM			
2006	22,921	17,688	40,609
2007	22,966	17,562	40,529
2008	22,845	17,191	40,036
2009 (Bridge)	22,629	16,784	39,413
2010	22,007	16,300	38,306
2011	n.a.	16,198	n.a.

Note. All figures are weather-normal.

Table 4c

End-Use Load Forecast Before and After CDM Impact
(GWh)

Year	Retail Customers	Embedded Customers	Total
Load Forecast Before Deducting Impact of CDM			
2006	23,115	17,839	40,955
2007	23,278	17,808	41,085
2008	23,277	17,531	40,808
2009 (Bridge)	23,340	17,255	40,594
2010	23,470	17,334	40,805
2011	23,578	17,447	41,025
Load Impact of CDM			
2006	194	151	345
2007	311	245	557
2008	432	340	771
2009 (Bridge)	601	471	1,072
2010	1,325	1,035	2,360
2011	1,604	1,249	2,853
Load Forecast After Deducting Impact of CDM			
2006	22,921	17,688	40,609
2007	22,966	17,562	40,529
2008	22,845	17,191	40,036
2009 (Bridge)	22,739	16,784	39,523
2010	22,145	16,300	38,444
2011	21,974	16,198	38,173

Note. All figures are weather-normal.

b) Hydro One does not use the weighting factor approach in this load forecast. The way alternative forecasts were taken into account in arriving at the final forecast is described below.

- For 2009, the annual econometric and end-use models predicted positive growth while the monthly econometric model predicted a negative growth. At the time of forecast, monthly load data was available for the first 3 months of 2009. The latest data indicated a negative growth for Hydro One Retail load resulting from the economic downturn. The annual models did not take into account of the latest information for 2009 as they are based on annual data ending in 2008. Consequently, for the year 2009, the forecast from the monthly econometric model was selected.

- For 2010, the annual econometric and end-use models, on average, predicted about 0.l% growth, while the monthly econometric model predicted 0.44% growth. The difference is essentially due to the fact that the load impact of the economic downturn was already taken into account by the monthly econometric model in 2009. Consequently, for the year 2010, the forecast from monthly econometric model was selected.

- For 2011, only annual forecasts were available for consideration because the monthly econometric model can only be used for short-term forecasting for up to 2 years. The growth rates from the annual econometric model and end-use model were similar. Consequently, for the year 2011, the growth rate from the econometric model was selected.

Energy Probe INTERROGATORY #10 List 1

Interrogatory

Issue 2.1 – Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit E1, Tab 1, Schedule 2, Updated

a) Please provide the most recent actual number of sentinel lights and sentinel light poles in 2009, as shown in Table 4.

b) Please provide the most recent year-to-date volumes for the items listed in Table 6, along with the corresponding year-to-date figures for 2008.

c) Please provide the late payment charge revenues for 2006 through 2008, along with the forecast for 2009.

d) Please provide the year-to-date late payment charges for 2009, along with the corresponding figure for 2008.

e) What is driving the decrease in late payment charges in 2011 relative to 2010?

f) Please provide the most recent year-to-date volume of new customer connections and upgrades as shown in Table 10 for 2009 and the corresponding period for 2008.

g) Please provide all studies and/or assumptions used to forecast the $5 million in revenues relating to the costs recoverable from MTO work involving distributed generation work.

Response

a) Sentinel lights to June 30, 2009 are 36,372.
Sentinel light poles to June 30, 2009 are 2,053.

b) The following table has been updated to show the year-to-date values.

	2008 Volumes As at September 2008	**2009 Year-to-date Volumes As of September 2009**
Dispute Meter Test	**43**	**42**
Collection of Account	**2173**	**2,093**
Disconnect/load Limiter/Reconnect Trips	**11206**	**10,441**
Account Set-up Charge	**92726**	**88,549**
In-Sufficient Funds (NSF) Cheque Charge	**6166**	**5,836**
Easement Charge for Unregistered Rights (approx)	**608**	**675**
Late Payment Charge applied to number of distinct accounts	**N/A**	**N/A**

c) The Late payment charges for 2006 through 2008 along with the forecast for 2009 are presented in the table below.

($ millions)	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Projected 2009**
LPC Revenues	$12.4	$14.2	$13.7	$13.4

d) The year-to-date late payment charge as of June 30, 2009 is $7.0M.
The late payment charge as of June 30, 2008 is $7.3M.

e) In 2010 the late payment charge revenue of $14.1M includes our assumption that sections of our customers will be impacted by the economic downturn and will be unable to settle their bills on a timely basis. The 2011 late fee charge revenue forecast of $13.7M includes our assumption that as the economic situation gets better, sections of our customers will be better equipped to pay their bills as they come due.

f) Customer connections and upgrades to September 30, 2009 were 11,056.
Customer connections and upgrades to September 30, 2008 were 12,899.

g) The external revenues of $5 million in test years 2010 and 2011 recoverable from the MTO does not represent work related to distributed generation. This instead represents the amounts for requests for relocations of distribution lines from both the MTO and Municipal Road Authorities.

The forecasted revenues are not supported by studies; they are based on a combination of history and our anticipation of additional requests through the Provincial Infrastructure incentive Programs that will result in increased road relocations.

Energy Probe INTERROGATORY #11 List 1

Interrogatory

Issue 2.1 – Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Ref: Exhibit E1, Tab 1, Schedule 2, pages 12 & 13 &
Exhibit C1, Tab 2, Schedule 11, page 2, Updated

The evidence at Exhibit C1, Tab 2, Schedule 11, page 2, Updated indicates that that Hydro One Distribution is expected to incur and recover costs amounting to $1.7 million for the provision of services to other Hydro One entities and that Hydro One is not adding a markup for providing these services to other Hydro One related entities.

The evidence at pages 12 and 13 of Exhibit E1, Tab 1, Schedule 2 indicates that there is $1.5 million in revenues related to work for other Hydro One entities, with an additional $0.2 million in revenue for other third party work.

Please explain why Hydro One is charging $1.5 million to other Hydro One entities for work that costs $1.7 million.

Response

Hydro One Distribution is expected to incur costs and recover revenue of $1.7 million for work and services performed for other Hydro One entities.

Work groups within Hydro One Networks such as - Lines, Engineering and Construction Services, and Forestry will be undertaking work for other Hydro One entities within the term of the Affiliate Relationship Code (ARC). Hydro One is also expected to incur and recover administrative related costs from other Hydro One entities. The cost estimates for 2010 and 2011 are as follows:

- Hydro One Remotes - $ 1.0 million in both years;
- Other Hydro One entities - $0.5 million in both years; and,
- Estimate for the recovery of administrative related costs from other Hydro One entities - $0.2 million.

Energy Probe INTERROGATORY #12 List 1

Interrogatory

Issue 3.1 – Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 1, Schedule 1 &
Exhibit A, Tab 17, Schedule 1, Appendix D, page 7

The evidence at Exhibit A states that:

> "PST/GST harmonization will take place in 2010 and there is considerable uncertainty as to the rules associated with tax harmonization. Hydro One's filing therefore does not address tax harmonization impacts."

a) Please confirm that Hydro One has not made any adjustments to the OM&A forecasts shown in Exhibit C1 to reflect the elimination of the 8% provincial sales tax.

b) Please provide the estimated costs of the provincial sales tax included in the OM&A forecast for each of 2010 and 2011.

c) Please provide the amount of provincial sales tax paid by Hydro One in each of 2006, 2007 and 2008 on OM&A expenses.

d) What is the expected reduction in compliance costs that will result from the reduction in the administrative burden on Hydro One to comply with two separate sets of tax rules?

Response

a) Hydro One confirms that this is correct.

b) Hydro One does not track the PST relating to expenditures. However, a process will be developed to estimate the savings in OM&A costs after July 1, 2010, that result from the PST/GST harmonization. Such estimated savings will be reflected in the deferral Account 1592. This information is not available at this time.

c) Hydro One does not track the PST relating to expenditures.

d) Until the proposed legislation and administrative rules are known, it is difficult to determine whether there will be any reduction or increase in compliance costs. However, it is anticipated that any change in costs would not be material.

Energy Probe INTERROGATORY #13 List 1

Interrogatory

Issue 3.6 – Is Hydro One's depreciation expense appropriate?

Ref: Exhibit C1, Tab 6, Schedule 1, Tables 1 & 2, Updated

a) Has Hydro One had any losses or gains on asset disposition as shown in Table 1 in 2009? If yes, please quantify.

b) Please explain the increase over more than 100% in the environmental assets as shown in Table 2.

Response

a) Hydro One has realized net gains on fixed asset dispositions totaling approximately $0.04M as of the end of Q2, 2009.

b) Hydro One Distribution's regulatory asset for PCB removal is amortized on a basis consistent with actual spending. The submitted increase in environmental asset amortization expense in the test years compared to the bridge year reflects higher planned PCB spending in those years as a direct result of the change in federal PCB regulations issued late in 2008. The increase in planned spending is required to meet the 2025 deadline for removal of all PCB's in concentrations 50 parts per million from the distribution system. (Please refer to Exhibit A, Tab 10, Schedule 1, Page 74, Note 12).

Energy Probe INTERROGATORY #14 List 1

Interrogatory

Issue 3.6 – Is Hydro One's depreciation expense appropriate?

Ref: Exhibit C1, Tab 6, Schedule 1, page 1, Updated

The evidence states that Hydro One used the Foster methodology for determining the depreciation rates currently in use.

a) Have any of the depreciation rates used in the current application changed from those used in the EB-2007-0681 filing? If yes, please provide the current and previous depreciation rate for each such asset category and provide a calculation to show the impact on the revenue requirement.

b) Please also provide all information used to determine the new depreciation rate and the Foster methodology used.

Response

a) Hydro One Distribution has not changed its depreciation rates since the EB-2007-0681 filing.

b) N/A

Energy Probe INTERROGATORY #15 List 1

Interrogatory

Issue 3.6 – Is Hydro One's depreciation expense appropriate?

Ref: Exhibit C2, Tab 5, Schedule 1, Updated

Please explain what is driving the increase in the major fixed asset depreciation rate and the minor fixed asset depreciation rate from 2008 through 2011. For example, what is the driver behind the increase in the minor fixed asset depreciation rate from 10.33% in 2009 to 11.97% in 2010?

Response

Both major and minor depreciation rate average changes are due only to asset mix. There has been no change in useful life determination or depreciation methodology since the EB-2007-0681 filing.

Higher in-service additions to computer hardware and software asset classes is the main factor causing the increase in major fixed asset average depreciation rate of 2.67% in 2009 to 2.97% in 2011. These asset classes have a higher depreciation rate than the average major fixed asset.

Higher in-service additions to the transportation equipment asset class is the main factor causing the increase in minor fixed asset average depreciation rate of 10.33% in 2009 to 11.97% in 2011. This asset class has a higher depreciation rate than the average minor fixed asset.

Energy Probe INTERROGATORY #16 List 1

Interrogatory

Issue 3.7 – Are the amounts proposed for capital and property taxes appropriate?

Ref: Exhibit C1, Tab 2, Schedule 12, pages 1 & 2

a) Property taxes are forecast to increase by more than 11% between 2008 and 2011. Please provide the underlying factors driving this increase.

b) Please provide the actual, or most recent information available, for the 2009 property taxes.

c) Please provide the total value assessment for all taxed properties for 2006 through 2008 and 2009 (if available). Please provide the forecast for 2009 through 2010 and explain the changes in the assessed values.

Response

a) The projected annual increases in property taxes are comprised of an increase for – 2% as result of increases in the assessed value of properties, and 2% due to municipal tax increase for year 2009 and 2010.

b) The expected property tax actual expenditures in are in line with 2009 bridge year forecast of $3.8M.

c) The table below summarizes the total value assessment for all Hydro One Networks' taxed properties for 2006 – 2010. The property assessments are conducted by Municipal Property Assessment Corporation (MPAC). In years 2007 & 2008 re-assessments were cancelled by the Province (Minister of Finance). The 2009 and 2010 forecast reflects recent property assessments that are being phased in over four year period.

Year	2006	2007	2008	2009	2010
Assessed Values $M	467	468	471	629	712

Energy Probe INTERROGATORY #17 List 1

Interrogatory

Issue 3.7 – Are the amounts proposed for capital and property taxes appropriate?

Ref: Exhibit C1, Tab 2, Schedule 12, Table 4

a) Please explain the decrease in rights payments costs between 2006 and 2008.

b) What is the actual rights payment for 2009?

c) What is driving the increase in rights payments between 2008 and 2009?

Response

The correct table number is Table 3 on page 4

a) The rights payments decrease in 2008 from the 2006 level is due to variables that include one time payments and timing of payments issued.

b) The expected rights payments actual expenditures are in line with 2009 bridge year forecast of $0.3M.

c) Hydro One does expects the rights payments to be in the range of approximately $0.3M across the bridge and test years.

Energy Probe INTERROGATORY #18 List 1

Interrogatory

Issue 3.8 – Is the amount proposed for income taxes, including the methodology, appropriate?

Ref: Exhibit C2, Tab 6, Schedule 1, Attachment B, Updated & Attachment D

Hydro One appears to calculate the CCA for Class 12 assets (computer software) in both 2009 and 2010 as if the half-year rule does not apply. Energy Probe is not aware of any changes to the half year rule for Class 12 assets. Energy Probe believes that the temporary change related to the half year rule is only applicable to the computers and systems software that would normally go into Class 50.

a) Please provide any tax rulings or information that supports the temporary removal of the half year rule for Class 12 assets.

b) Please recalculate the CCA for Class 12 assets for 2009, 2010 and 2011 assuming that the half year rule continues to apply. Please show the difference in the CCA for each of 2009, 2010 and 2011 compared to that calculated by Hydro One.

c) Based on the response to part (b) above, what is the impact on the revenue requirement in each of 2010 and 2011 of continuing to use the half year rule for Class 12 assets?

Response

a) Hydro One confirms that the temporary change related to the half year rule is only applicable to the computers and systems software that would normally go into Class 50 (new class 52 ~ 100%). Applications software that goes into class 12 continues to be subject to the half-year rule. Revised schedules Exhibit C2, Tab 6, Schedule 1, Attachment A, Attachment B & Attachment D are attached as Attachment 1, 2 and 3 respectively.

Please see revised schedules Exhibit C2, Tab 6, Schedule 1, Attachment B & Attachment D. Hydro One will reflect this updated information in our final rate order.

b)

	2009	2010	2011
CCA as Filed	364.0	323.7	307.8
Revised	317.7	346.2	330.6
Increase (decrease) in CCA	(46.3)	22.5	22.8

c) See revised schedules Exhibit C2, Tab 6, Schedule 1, Attachment A.

	2010	2011
Regulatory Income tax as Filed	12.7	39.5
Revised	2.5	30.5
Decrease in RR	10.2	9.0

EB-2009-0096 – EXHIBIT C2, TAB 6, SCHEDULE 1, ATTACHMENT A

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Utility Income Taxes
Forecast Years (2010 and 2011)
Year Ending December 31
($ Millions)

Line No.	Particulars	2010 (a)	2011 (b)
	Determination of Taxable Income		
1	Regulatory Net Income (before tax)	$ 159.4	$ 217.5
2	Book to Tax Adjustments:		
3	Other Post Employment Benefits expense	26.8	28.4
4	Other Post Employment Benefits payments	(26.8)	(28.5)
5	Inergi pension payments	0.0	0.0
6	Depreciation and amortization	259.2	291.3
7	Capital Cost Allowance	(346.2)	(330.6)
8	Removal costs	(1.9)	(1.9)
9	Environmental costs	(12.8)	(16.9)
10	Hedge loss - amortization	0.0	0.0
11	Non-deductible meals & entertainment	2.5	2.5
12	Capital amounts expensed under $2K	1.0	1.0
13	Research & Development ITC	0.1	0.1
14	Ontario education credits	1.3	1.3
15	Capitalized overhead costs	(23.2)	(23.5)
16	Capitalized pension costs	(26.8)	(27.8)
17		$ (146.7)	$ (104.6)
18	Regulatory Taxable Income	$ 12.7	$ 112.9
19	Corporate Income Tax Rate	31.00 %	28.25 %
20	Subtotal	$ 3.9	$ 31.9
21	Less: R&D ITC / Ontario education credits	(1.4)	(1.4)
22	Regulatory Income Tax	$ 2.5	$ 30.5
	Tax Rates		
23	Federal Tax	18.00 %	16.50 %
24	Provincial Tax	13.00 %	11.75 %
25	Total Tax Rate	31.00 %	28.25 %

EB-2009-0096 – EXHIBIT C2, TAB 6, SCHEDULE 1, ATTACHMENT B

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
Test Years
2010 & 2011 Networks Allocation to DX
Year Ending December 31
($ Millions)

2010 CCA Class		Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
	1	1,875.4	3.0	1,878.4	1.50	1,876.9	4%	75.1	1,803.3
	2	350.3	0.0	350.3	-	350.3	6%	21.0	329.3
	3	15.3	2.3	17.6	1.13	16.5	5%	0.8	16.8
	6	8.5	1.2	9.7	0.59	9.1	10%	0.9	8.8
	8	51.2	21.6	72.8	10.80	62.0	20%	12.4	60.4
	9	1.9	0.4	2.3	0.22	2.1	25%	0.5	1.8
	10	74.0	93.3	167.3	46.67	120.6	30%	36.2	131.1
	12	46.3	47.6	93.9	23.80	70.1	100%	70.1	23.8
	13	1.2	0.2	1.4	0.10	1.3	10 yrs	0.3	1.1
	17	2.8	0.3	3.1	0.16	2.9	8%	0.2	2.9
	42	0.3	0.0	0.3	0.02	0.3	12%	0.0	0.3
	45	2.5	(0.0)	2.5	(0.01)	2.5	45%	1.1	1.4
	47	1,187.6	449.0	1,636.6	224.50	1,412.1	8%	113.2	1,523.4
	52	4.5	9.2	13.7	4.60	13.7	100%	13.7	-
Dx CCA		3,621.7	628.2	4,249.9	314.08	3,940.4		345.6	3,904.3
Dx CEC Continuity		34.3	0.0	34.3	0.0	34.3	7%	2.4	31.9
						Less goodwill portion		(1.8)	
						Total CCA for RR		346.2	

2011 CCA Class		Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
	1	1,803.3	0.0	1,803.3	-	1,803.3	4%	72.1	1,731.2
	2	329.3	0.0	329.3	-	329.3	6%	19.8	309.6
	3	16.8	2.2	19.0	1.1	17.9	5%	0.9	18.1
	6	8.8	1.1	9.9	0.6	9.4	10%	0.9	9.0
	8	60.4	20.4	80.8	10.2	70.6	20%	14.1	66.7
	9	1.8	0.2	2.0	0.1	1.9	25%	0.5	1.5
	10	131.1	58.0	189.1	29.0	160.1	30%	48.0	141.1
	12	23.8	13.4	37.2	6.7	30.5	100%	30.5	6.7
	13	1.1	0.1	1.2	0.1	1.2	10 yrs	0.2	1.1
	17	2.9	0.4	3.2	0.2	3.1	8%	0.2	3.0
	42	0.3	0.0	0.3	0.0	0.3	12%	0.0	0.3
	45	1.4	0.0	1.4	-	1.4	45%	0.6	0.8
	47	1,523.4	432.4	1,955.8	216.2	1,739.6	8%	139.4	1,816.4
	50	-	9.6	9.6	4.8	4.8	55%	2.6	7.0
		3,904.3	538.0	4,442.3	269.0	4,173.3		330.0	4,112.3
Dx CEC Continuity		31.9	0.0	31.9	0.0	31.9	7%	2.2	29.6
						Less goodwill portion		(1.7)	
						Total CCA for RR		330.6	

EB-2009-0096 – EXHIBIT C2, TAB 6, SCHEDULE 1, ATTACHMENT D

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
Historic Years
2006 - 2009 Networks Tax Return Allocation to Distribution
Year Ending December 31
($ Millions)

2006 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,205.8	(0.4)	2,205.4	-	2,205.4	4%	88.2	2,117.2
2	448.7	-	448.7	-	448.7	6%	26.9	421.8
3	16.3	0.2	16.5	0.1	16.5	5%	0.8	15.7
6	9.1	0.1	9.2	0.1	9.1	10%	0.9	8.3
8	28.8	19.0	47.8	9.5	38.3	20%	7.7	40.1
10	56.5	25.7	82.2	12.9	69.3	30%	20.8	61.4
12	2.5	25.7	28.2	12.8	15.4	100%	15.4	12.8
13	2.4	(0.2)	2.2	-	2.2	10 yrs	0.4	1.8
17	2.3	0.1	2.4	0.1	2.3	8%	0.2	2.2
42	0.3	(0.0)	0.3	(0.1)	0.4	12%	0.0	0.3
45	7.9	7.9	15.8	3.9	11.9	45%	5.3	10.5
47	153.3	250.5	403.8	125.3	278.5	8%	22.3	381.5
Dx CCA	**2,933.8**	**328.7**	**3,262.5**	**164.6**	**3,098.0**		**188.9**	**3,073.6**
Dx CEC Continuity	**45.7**	**0.1**	**45.8**	**-**	**45.8**	**7%**	**3.2**	**42.6**
					Less goodwill portion		**(2.4)**	
					Total ECE for RR		**0.8**	

2007 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,117.2	2.6	2,119.8	-	2,119.8	4%	85.0	2,034.8
2	421.8	(0.1)	421.7	-	421.7	6%	25.3	396.4
3	15.7	-	15.7	0.1	15.7	5%	0.8	14.9
6	8.3	0.9	9.2	0.5	8.7	10%	0.9	8.3
8	40.1	15.1	55.2	7.5	47.7	20%	9.5	45.7
9	-	1.5	1.5	0.5	0.8	25%	0.2	1.3
10	61.4	25.8	87.2	12.9	74.3	30%	22.3	64.9
12	12.8	7.2	20.0	3.7	16.3	100%	16.3	3.7
13	1.8	(0.2)	1.6	-	1.6	10 yrs	0.1	1.5
17	2.2	0.7	2.9	0.3	2.6	8%	0.2	2.7
42	0.3	0.1	0.4	0.1	0.4	12%	0.0	0.3
45	10.5	2.8	13.3	1.4	11.9	45%	5.3	8.0
47	381.5	278.9	660.4	147.7	512.7	8%	41.0	619.4
50	-	7.6	7.6	3.8	3.8	55%	2.0	5.6
Dx CCA	**3,073.6**	**342.9**	**3,416.5**	**178.5**	**3,237.9**		**209.0**	**3,207.5**
Dx CEC Continuity	**42.6**	**-**	**42.6**	**-**	**42.6**	**7%**	**3.0**	**39.6**
					Less goodwill portion		**(2.2)**	
					Total ECE for RR		**0.8**	

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Calculation of Capital Cost allowance (CCA)
Historic and Bridge Years
2006 - 2009 Networks Allocation to Distribution
Year Ending December 31
($ Millions)

2008 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	2,034.8	0.16	2,035.0	0.1	2,035.2	4%	81.3	1,953.6
2	396.4	-	396.4	-	396.4	6%	23.8	372.6
3	14.9	-	14.9	-	14.9	5%	0.7	14.1
6	8.3	0.81	9.1	0.4	8.7	10%	0.9	8.3
8	45.7	15.45	61.2	7.7	53.4	20%	10.6	50.6
9	1.3	3.54	4.8	1.8	3.1	25%	0.8	4.1
10	64.9	30.44	95.4	15.2	80.1	30%	24.0	71.3
12	3.7	60.37	64.1	30.2	33.9	100%	33.9	30.2
13	1.5	-	1.5	-	1.5	10 yrs	0.2	1.3
17	2.7	0.11	2.8	0.1	2.8	8%	0.2	2.6
42	0.3	-	0.3	-	0.3	12%	0.0	0.3
45	8.0	-	8.0	-	8.0	45%	3.6	4.4
47	619.4	326.74	946.1	163.4	782.8	8%	62.6	883.5
50	5.6	10.33	15.9	5.2	10.8	55%	5.9	9.9
Dx CCA	**3,207.5**	**447.9**	**3,655.5**	**223.9**	**3,431.8**		**248.6**	**3,406.8**
Dx CEC Continuity	**39.6**		**39.6**		**39.62**	**7%**	**2.8**	**36.8**
					Less goodwill portion		**(2.1)**	
					Total ECE for RR		**0.7**	

2009 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,953.64	-	1,953.6	-	1,953.6	4%	78.2	1,875.4
2	372.60	0.10	372.7	0.0	372.7	6%	22.4	350.3
3	14.15	1.95	16.1	1.0	15.1	5%	0.8	15.3
6	8.25	1.15	9.4	0.6	8.8	10%	0.9	8.5
8	50.57	11.93	62.5	6.0	56.5	20%	11.3	51.2
9	4.07	(1.37)	2.7	(0.7)	3.4	25%	0.8	1.9
10	71.32	28.28	99.6	14.1	85.5	30%	25.6	74.0
12	30.18	92.62	122.8	46.3	76.5	100%	76.5	46.3
13	1.33	0.17	1.5	0.2	1.5	10 yrs	0.3	1.2
17	2.60	0.40	3.0	0.2	2.8	8%	0.2	2.8
42	0.27	0.03	0.3	0.0	0.3	12%	0.0	0.3
45	4.40	(0.00)	4.4	(0.0)	4.4	45%	1.9	2.5
47	883.52	390.38	1,273.9	195.2	1,078.7	8%	86.3	1,187.6
50	9.91	6.99	16.9	7.0	16.9	55%	12.4	4.5
Dx CCA	**3,406.8**	**532.6**	**3,939.4**	**269.9**	**3,676.7**		**317.7**	**3,621.7**
Dx CEC Continuity	**36.8**		**36.8**		**36.8**	**0.1**	**2.6**	**34.3**
					Less goodwill portion		**(1.9)**	
					Total ECE for RR		**0.6**	

Energy Probe INTERROGATORY #19 List 1

Interrogatory

Issue 3.8 – Is the amount proposed for income taxes, including the methodology, appropriate?

Ref: Exhibit C2, Tab 6, Schedule 1, Attachment A, Updated

a) Please indicate where in this schedule there are adjustments related to each of the following:
   i) investment tax credits on SR&ED expenditures;
   ii) co-operative education tax credit (CETC); and
   iii) apprenticeship training tax credit (ATTC).

b) Has Hydro One increased the CETC rate from 10% to 25% of salaries and wages paid and increased the limit from $1,000 to $3,000 per work placement?

c) Has Hydro One reflect the in changes in the ATTC that now allow a deduction of 35% of wages and salaries paid to a maximum credit of $10,000 per apprentice, and extending the period for the first 48 months of an apprenticeship?

d) Please provide the calculations/information required to calculate the CETC and ATTC for each of 2008 through 2012 (where appropriate) using the rules (rates, maximums, etc.) that were in place in each year. Please note that the 2008 ATTC does not need to included, as it is found in Part 21 of the 2008 income tax return provided as Attachment A to Exhibit C2, Tab 6, Schedule 2.

Response

a) The adjustments relating to investment tax credits for SR&ED expenditures, CETC and ATTC are reflected on line 21 of Exhibit C2, Tab 6, Schedule 1, Attachment A.

b) Hydro One confirms that it has adjusted the estimated CETC for these changes.

c) Hydro One confirms that it has adjusted the estimated ATTC for these changes.

d) Part 21 of the 2008 income tax return provided in Exhibit C2, Tab 6, Schedule 2, Attachment A, pertains to the entity Hydro One Networks which includes both the Transmission and Distribution business. The estimated Distribution benefits for the years subsequent to 2008, relating to CETC and the ATTC, were based on the Distribution portion of the 2008 return filed, adjusted for the estimated impacts of changes noted in b) and c).

The Distribution estimates were calculated as follows:

	2008	Estimate for each of 2010/2011
CETC	$0.1M	$0.3M
ATTC	$0.8M	$1.0M
ITC SRED	$0.1M	$0.1M
Total	$1.0M	$1.4M

Energy Probe INTERROGATORY #20 List 1

Interrogatory

Issue 4.1 – Are the amounts proposed for Rate Base appropriate?

Ref: Exhibit D1, Tab 1, Schedule 5

a) Please reconcile the figure of 22.6 shown as the year end inventory level in 2006 in Table 1 with the figure of 23.1 shown for December, 2006 in Table 2.

b) Please update Table 2 to reflect the most recent actual information available for the 2009 monthly inventory levels.

c) Does Hydro One have a forecast for the monthly inventory levels in 2010 and 2011? If yes, please provide this forecast.

d) Please reconcile the $30.0 million shown in Table 1 for 2011 with the figures of $10.5 million for materials and supplies and the $19.3 million in Note 1, both in Exhibit D2, Tab 4, Schedule 1, Updated.

Response

a) The 2006 year-end inventory levels of $22.6 million shown in Table 1 do not include approximately $500K for smart meter inventory. The amount of $23.1 million in Table 2 includes the $500K smart meter inventory.

b) The updated table to June 2009 is shown below.

$M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2006	23.9	25.3	27.4	27.6	26.8	26.0	26.3	24.9	23.3	23.7	23.6	23.1
2007	24.1	23.9	26.0	27.1	28.0	28.1	28.5	28.3	28.7	27.2	28.8	28.5
2008	27.2	27.9	31.9	32.4	29.1	31.4	31.5	31.6	30.7	30.9	32.7	41.0
2009	35.3	37.4	38.9	39.1	39.2	41.6	30.0*	29.9*	29.8*	29.7*	29.5*	29.6*

* Forecasted levels.

c) It is not Hydro One's practice to forecast monthly inventory levels beyond the current calendar year. The inventory for test years 2010 and 2011 are forecasted at year-end levels.

d) For the requested reconciliation, the year-end inventory value of $30.2 million should be used rather than “Annual Average inventory value of $30.0 million”. Note 1 should read $19.6 for 2011, instead of $19.3. [Therefore $19.6 + $10.5 = $30.1], with a rounding difference of ($0.1).

Energy Probe INTERROGATORY #21 List 1

Interrogatory

Issue 4.1 – Are the amounts proposed for Rate Base appropriate?

Interrogatory # 21

Ref: Exhibit D1, Tab 3, Schedule 1 &
Exhibit A, Tab 17, Schedule 1, Appendix D, page 7

The evidence at Exhibit A states that:

> "PST/GST harmonization will take place in 2010 and there is considerable uncertainty as to the rules associated with tax harmonization. Hydro One's filing therefore does not address tax harmonization impacts."

a) Please confirm that Hydro One has not made any adjustments to the capital expenditure forecasts shown in Exhibit D1, Tab 3, Schedule 1 to reflect the elimination of the 8% provincial sales tax.

b) Please provide the estimated costs of the provincial sales tax included in the capital expenditures included in rate base forecast for each of 2010 and 2011.

c) Please provide the amount of provincial sales tax paid by Hydro One on capital expenditures included in rate base in each of 2006, 2007 and 2008.

Response

a) Hydro One confirms that this is correct.

b) Hydro one does not track the PST relating to expenditures. However, a process will be developed to estimate the savings in capital expenditures after July 1, 2010, that result from the PST/GST harmonization. Such estimated savings will be reflected in the deferral Account 1592. This information is not available at this time.

c) Hydro One does not track the PST relating to expenditures.

Energy Probe INTERROGATORY #22 List 1

Interrogatory

Issue 4.5 – Are the inputs used to determine the Working Capital component of the Rate Base appropriate and is the methodology used consistent with the methodologies approved by the Board in previous Hydro One rate applications?

Ref: Exhibit D1, Tab 1, Schedule 4, Updated

Please update Tables 1 & 2 to reflect the harmonization of the provincial sales tax with the goods and services tax effective July 1, 2010. For the purposes of the calculation please assume that the GST is effectively 9% for 2010 and 13% for 2011. Please also reflect the removal of any provincial sales tax included in the expenses.

Response

Hydro One does not track the PST relating to expenditures and therefore cannot update Table 1 and Table 2 to reflect the requested scenario. Refer to Exhibit H, Tab 3, Schedule 12 and Exhibit H, Tab 3, Schedule 21.

In the OEB's EB-2008-0272 Decision (Hydro One Transmission's 2010/2011 Rate Filing), the Board approved the continuation of Accounts 1592, 1508, 2405. The Board acknowledged that Hydro One indicated that it would use Account 1592 to capture the impacts of tax rate changes that may arise from the harmonization of PST and GST. Refer to EB-2008-0272 Decision, section 8.2, page 56.

Energy Probe INTERROGATORY #23 List 1

Interrogatory

Issue 4.5 – Are the inputs used to determine the Working Capital component of the Rate Base appropriate and is the methodology used consistent with the methodologies approved by the Board in previous Hydro One rate applications?

Ref: Exhibit D1, Tab 1, Schedule 4, Table 1, Updated

a) Please provide a table showing the detailed calculation of the cost of power figures of $2,008.4 and $1,994.6 for 2010 and 2011 into their component parts, including transmission costs and commodity costs. For each component, please show the volumetric figure used and corresponding rate used.

b) For the commodity cost, please reconcile the volume figures used with the forecast of GWh provided in Table 4 of Exhibit A, Tab 14, Schedule 4.

c) What is the volume associated with market participants served by Hydro One? Has Hydro One removed all the volumes for market participants before calculating the cost of power to be used in the working capital allowance? If not, why not?

d) Did Hydro One use the average supply cost for RPP customers of $60.72/MWh as set out in the April 15, 2009 Regulated Price Plan Price Report? If not, how did Hydro One determine the appropriate commodity price to use?

e) If available before interrogatory responses are due, please update the cost of power and the associated working capital component of rate base to reflect any more recent Regulated Price Plan Price Report.

Response

a) Detailed calculation of the cost of power figures of $2,008.4 and $1,994.6 for 2010 and 2011 are as follows:

2010 Cost of Power	Rate $/MWh / $/kW	Volume GWh/GW		2010
Commodity	61.70	25,021	$	1,543.8
WMSC (Incl RRRP)	6.20	25,021	$	155.1
Tx Network	2.57	65	$	167.3
Tx Line Connection	0.70	55	$	38.6
Tx Transf Connection	1.62	64	$	103.6
Total COP			**$**	**2,008.4**

2011 Cost of Power	Rate $/MWh / $/kW	Volume GWh/GW		2011
Commodity	61.70	24,849	$	1,533.2
WMSC (Incl RRRP)	6.20	24,849	$	154.1
Tx Network	2.57	65	$	166.4
Tx Line Connection	0.70	55	$	38.3
Tx Transformation Connection	1.62	63	$	102.6
Total COP			**$**	**1,994.6**

b) Reconciliation of the volume figures used in the Cost of Power calculation and the forecast of GWh provided in Table 4 of Exhibit A, Tab 14, Schedule 4 is as follows:

In GWh's		**2010**	**2011**
Load Forecast After Deducting Impact of CDM			
Retail Customer Purchases - per Table 4, ExhA-14-4		22,007	21,851
Average Loss Factor	÷	1.079	1.079
Net Retail Customer Sales	(A)	20,405	20,261
Embedded Non-Market Participant Purchases		2,997	2,981
Loss Factor	÷	1.034	1.034
Net Embedded Non-Market Participant Sales	(B)	2,898	2,883
Total Sales	(A) + (B)	23,304	23,144
Total Average Loss Factor	x	1.074	1.074
Total Purchases used in COP calculation		**25,021**	**24,849**

c) The volume associated with market participants served by Hydro One is 13,302 GWh for 2010 and 13,217 GWh for 2011. Hydro One does not include the volumes for market participants in the calculation of cost of power.

d) The commodity price Hydro One used was a weighted average rate for both RPP and non-RPP customers. The rate used for RPP customers was $60.72/MWh, consistent with the April 15, 2009 Regulated Price Plan Price Report. The rate used for non-RPP customers was $63.88/MWh which was the sum of the forecasted HOEP $49.62/MWh, consistent with the April 15, 2009 Ontario Wholesale Electricity Market Price Forecast, and the forecasted Global Adjustment of $14.26/MWh, consistent with the April 15, 2009 Regulated Price Plan Price Report. The calculation is as follows:

	Rate - $/MWh	Weighting	WA Rate $/MWh
* Forecasted Average HOEP	49.62		
** Forecasted Average Global Adjustment	14.26		
Forecasted Average non-RPP cost	63.88	31%	19.80
** Forecasted Average RPP cost	60.72	69%	41.90
Weighted Average Commodity Cost			**61.70**

Note:
* Per April 15, 2009 Ontario Wholesale Electricity Market Price Forecast
** Per April 15, 2009 Regulated Price Plan Price Report

e) The Regulated Price Plan Price Report has not been updated since the April 15, 2009 submission.

Energy Probe INTERROGATORY #24 List 1

Interrogatory

Issue 5.1 – Is the proposed Capital Structure and Rate of Return on Equity for Hydro One's distribution business appropriate?

Ref: Exhibit B1, Tab 1, Schedule 1, page 1

The evidence states that Hydro One expects that if the Board changes the return on equity, long term debt rate and/or short term debt rate as a result of the review of the existing Cost of Capital policy (EB-2009-0084), that these values will be reflected in the Board's final decision on this application. Is the same true if the Board were to change the capital structure, such as the amount of long term and short term debt?.

Response

Yes, Hydro One expects that the draft rate order would reflect any changes by the Board to the capital structure as appropriate.

Energy Probe INTERROGATORY #25 List 1

Interrogatory

Issue 5.1 – Is the proposed Capital Structure and Rate of Return on Equity for Hydro One's distribution business appropriate?

Ref: Exhibit B1, Tab 1, Schedule 1, pages 2 & 3

a) Please update the return on equity for 2010 and 2011 based on the September 2009 Consensus Forecasts and Bank of Canada data for September 2009. Please provide the impact on the revenue requirement for both 2010 and 2011.

b) Please update the 2010 short term debt rate based on the September 2009 Bank of Canada data and the 2011 short term debt rate using the most recent Global Insight forecast currently available. Please provide the impact on the revenue requirement for both 2010 and 2011.

Response

a) The return on equity for 2010 and 2011 based on the September 2009 Consensus Forecasts and Bank of Canada data for September 2009 is found in the table below.

The 30 year Long Canada Bond yield forecast for 2010 is based on the September 2009 Consensus Forecast for the 10 year Canada yield plus the average difference between the 10 and 30 year Government of Canada bond yield during September 2009.

The 30 year Long Canada Bond yield forecast for 2011 is based on the long term April 2009 Consensus Forecast (provided semi-annually in April and October) for the 10 year Canada yield plus the average difference between the 10 and 30 year Government of Canada bond yield during September 2009.

	2010	**2011**
Initial ROE	9.35%	9.35%
30 year Canada	4.42%	4.92%
Less Initial 30 year Canada	5.50%	5.50%
Yield Change	-1.08%	-0.58%
Adjustment (75% of change)	-0.81%	-0.44%
ROE	**8.54%**	**8.92%**

This would result in an increase in revenue requirement for 2010 by approximately $12.1M. Revenue requirement in 2011 will decrease by $4.9M.

Hydro One is not planning on updating its 2010/2011 Distribution rate filing for changes in planning assumptions other than for cost of capital as noted in A-3-1, pages 2 and 3. 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 short term debt rate forecast for 2010 is based on the September 2009 Consensus Forecast for the 3 month T-bill yield plus the average difference between the 3 month T-bill rate and 3 month Bankers Acceptance rate during September 2009 (based on Bank of Canada data). The short term debt rate forecast for 2011 is based on the June 2009 (the most recent available) Global Insight forecast for the 3 month Bankers' Acceptance rate.

	2010	**2011**
3 Month Bankers' Acceptance Rate	1.09%	2.49%
Fixed Spread (25 basis points)	0.25%	0.25%
Short Term Debt Rate	**1.34%**	**2.74%**

The impact on revenue requirement in 2010 would be an increase of approximately $0.3M. Revenue requirement in 2011 remains unchanged due to the minimal decrease of the allowed return on short-term debt rate.

Energy Probe INTERROGATORY #26 List 1

Interrogatory

Issue 5.1 – Is the proposed Capital Structure and Rate of Return on Equity for Hydro One's distribution business appropriate?

Ref: Exhibit B2, Tab 1, Schedule 1, page 2, Updated

What is the impact on the revenue requirement in each of 2010 and 2011 if the notional long-term debt shown in the table were costed as short-term debt (i.e. only the actual cost of long-term debt was included in revenue requirement and any unfunded debt was treated as short-term debt)?

Response

Assuming notional long-term debt was costed as short-term debt in 2010 and 2011, revenue requirement would decrease by $7.1M and $0.7M, respectively. This was calculated by applying the short-term debt rate of 1.19% in 2010 and 2.76% in 2011 to the notional long-term debt amounts.

Energy Probe INTERROGATORY #27 List 1

Interrogatory

Issue 5.2 – Are Hydro One's proposed costs and mix for its short and long-term debt for the 2010/2011 test years appropriate?

Ref: Exhibit B1, Tab 2, Schedule 1

Please update Table 4 to reflect the most recent Consensus Forecasts and the corresponding month average spreads, as well as the corresponding average of indicative new issue spreads obtainable from the Company's MTN dealer group.

Response

Table 4 from Exhibit B1, Tab 2, Schedule 1 is updated below to reflect the Consensus Forecasts for the month of September and the corresponding month average spreads from the Company's MTN dealer group.

Table 4
Forecast Yield for 2009-2011 Issuance Terms

	2009		
	5-year	**10-year**	**30-year**
Government of Canada	2.83%	3.60%	4.12%
Hydro One Spread	0.73%	1.03%	1.42%
Forecast Hydro One Yield	3.56%	4.63%	5.54%
	2010		
	5-year	**10-year**	**30-year**
Government of Canada	3.13%	3.90%	4.42%
Hydro One Spread	0.73%	1.03%	1.42%
Forecast Hydro One Yield	3.86%	4.93%	5.84%
	2011		
	5-year	**10-year**	**30-year**
Government of Canada	3.63%	4.40%	4.92%
Hydro One Spread	0.73%	1.03%	1.42%
Forecast Hydro One Yield	4.36%	5.43%	6.34%

Each rate is comprised of the forecast Canada bond yield plus the Hydro One Inc. credit spread applicable to that term. The ten-year Government of Canada bond yield forecast for 2009 and 2010 is based on the September 2009 Consensus Forecasts, and for 2011 is based on the long term April 2009 Consensus Forecast (provided semi-annually in April and October). The five- and 30-year Government of Canada bond yield forecasts are derived by adding the September 2009 average spreads (five-year to ten-year for the five-year forecast and 30-year to ten-year for the 30-year forecast) to the ten-year Government of Canada bond yield forecast. Hydro One's credit spreads over the Government of Canada bonds are based on the average of indicative new issue spreads for September 2009 obtained from the Company's MTN dealer group for each planned issuance term.

Energy Probe INTERROGATORY #28 List 1

Interrogatory

Issue 5.2 – Are Hydro One's proposed costs and mix for its short and long-term debt for the 2010/2011 test years appropriate?

Ref: Exhibit B1, Tab 2, Schedule 1, page 8 &
Exhibit B2, Tab 1, Schedule 2, Updated

The actual treasury OM&A costs for 2006 through 2008 range from $0.7 million to $0.8 million. The forecast for 2010 and 2011 is $1.1 million.

a) Please explain the nearly 40% increase in these costs for 2010 and 2010 from the 2008 level.

b) Please provide the most recent year-to-date actual cost for 2009 and the corresponding period for 2008. Please explain any significant increase in the 2009 costs.

Response

a) Treasury OM&A costs are increasing in the test years due to higher staff levels, not just wage levels, given the expectation that the borrowing program will increase significantly in the test period, as stated on page 55, of EB-2008-0272.

b) Treasury OM&A attributable to Distribution for June 30, 2009 was $0.35 million and $0.41 million for June 30, 2008. The lower actual cost for 2009 is attributable to attrition and lag in hiring new staff.

Energy Probe INTERROGATORY #29 List 1

Interrogatory

Issue 5.2 – Are Hydro One's proposed costs and mix for its short and long-term debt for the 2010/2011 test years appropriate?

Ref: Exhibit B2, Tab 1, Schedule 2, page 4

The table for the 2009 bridge year shows the offering 10 year debt in June and September of 2009. Please update this schedule to show the actual debt placed by Hydro One so far in 2009, along with any additional placements forecast for the remainder of the year.

Response

Please see Attachment 1.

Lines 26 to 29 of Attachment 1 represent actual debt issues placed by Hydro One during 2009, while line 30 reflects the additional placement forecast for the remainder of 2009.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Cost of Long-Term Debt Capital
Bridge Year (2009)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/08 ($Millions)	Total Amount Outstanding at 12/31/09 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	3-Jun-00	7.150%	3-Jun-10	121.6	1.6	120.0	98.70	7.34%	121.6	121.6	121.6	8.9	
2	3-Jun-00	7.350%	3-Jun-30	121.6	2.0	119.6	98.37	7.49%	121.6	121.6	121.6	9.1	
3	22-Jun-01	6.400%	1-Dec-11	76.0	(0.2)	76.2	100.28	6.36%	76.0	76.0	76.0	4.8	
4	22-Jun-01	6.930%	1-Jun-32	47.7	0.5	47.3	99.05	7.01%	47.7	47.7	47.7	3.3	
5	17-Sep-02	5.770%	15-Nov-12	213.0	1.0	212.0	99.55	5.83%	213.0	213.0	213.0	12.4	
6	17-Sep-02	6.930%	1-Jun-32	142.0	(5.3)	147.3	103.71	6.64%	142.0	142.0	142.0	9.4	
7	31-Jan-03	5.770%	15-Nov-12	111.0	(0.5)	111.5	100.48	5.70%	111.0	111.0	111.0	6.3	
8	31-Jan-03	6.350%	31-Jan-34	74.0	0.6	73.4	99.21	6.41%	74.0	74.0	74.0	4.7	
9	22-Apr-03	6.590%	22-Apr-43	105.0	0.8	104.2	99.26	6.64%	105.0	105.0	105.0	7.0	
10	24-Feb-04	3.950%	24-Feb-09	87.5	0.4	87.1	99.55	4.05%	87.5	0.0	13.5	0.5	
11	25-Jun-04	6.350%	31-Jan-34	48.0	(0.1)	48.1	100.22	6.33%	48.0	48.0	48.0	3.0	
12	20-Aug-04	6.590%	22-Apr-43	26.0	(2.1)	28.1	107.89	6.06%	26.0	26.0	26.0	1.6	
13	24-Aug-04	6.350%	31-Jan-34	26.0	(0.9)	26.9	103.48	6.09%	26.0	26.0	26.0	1.6	
14	19-May-05	5.360%	20-May-36	98.1	3.5	94.6	96.44	5.60%	98.1	98.1	98.1	5.5	
15	19-May-05	3.950%	24-Feb-09	45.0	(0.4)	45.4	100.90	3.69%	45.0	0.0	6.9	0.3	
16	3-Mar-06	4.640%	3-Mar-16	90.0	0.4	89.6	99.52	4.70%	90.0	90.0	90.0	4.2	
17	24-Apr-06	5.360%	20-May-36	62.5	0.8	61.7	98.68	5.45%	62.5	62.5	62.5	3.4	
18	22-Aug-06	4.640%	3-Mar-16	90.0	1.1	88.9	98.75	4.80%	90.0	90.0	90.0	4.3	
19	19-Oct-06	5.000%	19-Oct-46	45.0	0.3	44.7	99.29	5.04%	45.0	45.0	45.0	2.3	
20	13-Mar-07	4.890%	13-Mar-37	160.0	0.8	159.2	99.48	4.92%	160.0	160.0	160.0	7.9	
21	18-Oct-07	5.180%	18-Oct-17	75.0	0.3	74.7	99.63	5.23%	75.0	75.0	75.0	3.9	
23	3-Mar-08	5.180%	18-Oct-17	120.0	(2.1)	122.1	101.73	4.95%	120.0	120.0	120.0	5.9	
24	10-Nov-08	5.000%	12-Nov-13	160.0	0.8	159.2	99.53	5.11%	160.0	160.0	160.0	8.2	
25	19-Nov-08	3.890%	19-Nov-10	40.0	0.1	39.9	99.78	4.01%	40.0	40.0	40.0	1.6	
26	13-Jan-09	3.890%	19-Nov-10	35.0	(0.2)	35.2	100.67	3.51%	0.0	35.0	32.3	1.1	
27	14-Jan-09	5.000%	12-Nov-13	70.0	(2.0)	72.0	102.87	4.33%	0.0	70.0	64.6	2.8	
28	3-Mar-09	6.030%	3-Mar-39	105.0	0.6	104.4	99.43	6.07%	0.0	105.0	80.8	4.9	
29	16-Jul-09	5.490%	16-Jul-40	90.0	0.6	89.4	99.37	5.53%	0.0	90.0	41.5	2.3	
30	15-Nov-09	4.770%	15-Nov-19	12.6	0.1	12.5	99.50	4.83%	0.0	12.6	1.9	0.1	
31		**Subtotal**							2185.0	2365.1	2294.1	131.6	
32		Treasury OM&A costs										1.2	
33		Other financing-related fees										0.6	
34		**Total**							2185.0	2365.1	2294.1	133.4	5.81%

Energy Probe INTERROGATORY #30 List 1

Interrogatory

Issue 5.2 – Are Hydro One's proposed costs and mix for its short and long-term debt for the 2010/2011 test years appropriate?

Ref: Exhibit B2, Tab 1, Schedule 2, pages 5 & 6, Updated

a) What is the impact on the revenue requirement in each of 2010 and 2011 if the 30 year debt forecast to be issued in March of 2010 and 2011 was replaced with 5 and 10 year debt, with each consisting of 50% of the planned long term debt amount?

b) What was/is the weighted average remaining term of the long-term debt based on the average of monthly averages for each of 2006, 2007, 2008, and as forecast by Hydro One for 2009, 2010 and 2011?

c) What would be the weighted average remaining term of the long-term debt based on the average of monthly averages for 2010 and 2011 if the 30 year issues forecast for 2010 and 2011 were replaced with the 5 and 10 year issues as indicated in part (a) above?

Response

a) Assuming that both 2010 and 2011 March 30 year debt issuances were replaced with 5 and 10 year debt issuances, the average cost of long-term debt would decrease to 5.63% and 5.56% in 2010 and 2011, respectively. Since the total amount of debt in the 30 year issuance will be spread out evenly across 5 and 10 year borrowing, there will be no change in the total debt outstanding. Due to the lower cost of long-term debt, revenue requirement will decrease by approximately $2.3M in 2010 and $4.5M in 2011. As stated on lines 12 to 14 on page 1 of Exhibit B1, Tab 2, Schedule 1, Hydro One Inc's debt financing strategy takes into consideration the objectives of cost effectiveness, distributing debt maturities evenly over time, and ensuring the term of the debt portfolio is compatible with the long life of the Company's assets.

b) The chart below indicates the weighted average remaining term of the long-term debt based on the average of the monthly averages effective January 1, in each given year.

	2006	2007	2008	2009	2010	2011
Average Remaining Term (in years)	13.4	15.1	15.6	15.1	15.1	15.4

c) The chart below indicates the weighted average remaining term of the long-term debt based on the average of the monthly averages effective January 1, assuming 30 year debt is replaced with 5 year and 10 year debt issuance for the test years.

	2010	2011
Average Remaining Term (in years)	14.0	13.4

Energy Probe INTERROGATORY #31 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 1, page 2

Please update Table 2 to reflect the most recent information available for 2009, including use of the current Board's prescribed interest rate.

Response

Table 2
Distribution
Regulatory Assets Requested for Approval
Actuals as of June 30, 2009
Interest Improved to December 31, 2009 at Board Prescribed Rates
$ Million

Description	**Dec 31, 2009**
Retail Service Cost Variance Accounts	(2.1)
Smart Meter Minimum Functionality Under-recovery Jan 1 to Dec 31, 2008	0.9
Smart Meter Exceeding Min Functionality Under-recovery Jan 1 to Dec 31, 2008	1.1
Retail Settlement Variance Accounts	(7.1)
Regulatory Asset Recovery Phase I	(23.0)
Total Regulatory Assets for Approval	(30.2)

Energy Probe INTERROGATORY #32 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 1, page 6

Please explain the significant drop in the balance in the RSVA account shown in Table 6 from (20.9) at the end of 2008 to (2.9) at the end of 2009.

Response

Please refer to response at Exhibit H, Tab 1, Schedule 115.

Energy Probe INTERROGATORY #33 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 1, page 8

a) Please provide the December 31, 2008 balance and the projected December 31, 2009 balance for each of the accounts shown on page 8.

b) Why is Hydro One not requesting disposition of these accounts in this proceeding?

Response

a) Balance as at December 31, 2008:

RRRP	$17.3M
Deferred Pension	$0.0M
Regulatory Rate Rider 2	$43.3M
Regulatory Rate Rider 3	$(72.6)M
Regulatory Rate Rider 4	$25.0M
Harmonization Mitigation Credit	$0.0M

Forecast balances as at December 31, 2009:

RRRP	$19.3M
Deferred Pension	$1.5M
Regulatory Asset Recovery 2	$19.7M
Regulatory Asset Recovery 3	$(48.1)M
Regulatory Asset Recovery 4	$18.2M
Harmonization Mitigation Credit	$0.1M

b) Hydro One Distribution is not requesting disposition of the following accounts due to the following reasons:

- Rural and Remote Electricity Rate Protection (RRRP) – Hydro One collects the RRRP amount paid by all customers in Ontario, not just Hydro One customers. Ontario Regulation 442/01 has an annual adjustment mechanism for the OEB to revise the RRRP rate as needed. The balance in the RRRP variance account will decrease with OEB approval of a new RRRP rate as of May 1, 2009.
- Deferred Pension – There was no balance in the Deferred Pension accounts at December 31, 2008.
- Rate Rider #2 is scheduled to terminate April 30, 2010. Hydro One is proposing that Rider #2 ends at the same time the new 2010 distribution rates are implemented. Any over/under recovery will be cleared at a future Proceeding.
- Rate Rider #3 is scheduled to terminate April 30, 2011.
- Rate Rider #4 is scheduled to terminate April 30, 2011.
- Bill Impact Mitigation – The Bill impact mitigation account is still active. Impact mitigation continues to be applied to customers until January 31, 2010, so it would be premature to clear this variance account in this Proceeding.

Energy Probe INTERROGATORY #34 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 1, Table 2

a) Which of the accounts shown in Table 2 does Hydro One propose to continue for 2010 and 2011?

b) Which of the accounts shown in Table 2 does Hydro One propose be closed at the end of 2011?

Response

a) The Retail Cost Variance Accounts and Retail Settlement Variance Accounts will continue in 2010 and 2011.

b) The Regulatory Asset Recovery Phase I account and the Smart Meter Accounts will be closed at the end of 2011.

Energy Probe INTERROGATORY #35 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 3, page 1

Please explain why there are no costs associated with stranded meters in 2010 or 2011. What is the net book value of the meters that are forecast to be removed from service in each of 2010 and 2011?

Response

Hydro One Distribution does not have stranded meter costs resulting from the deployment of smart meters. This is consistent with the Foster Associates Inc. recommendation made in EB-2005-0378 (Exhibit C1, Tab 7, Schedule 2. p. 11) that conventional meters be amortized on a straight-line basis over a 5 year period, which was approved as part of Hydro One's 2006 Distribution Rate Application (EB-2005-0378) and was a settled issue in Hydro One's 2008 Distribution Rate Application (EB-2007-0681).

Energy Probe INTERROGATORY #36 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 3, pages 9, 14, & 17

The note on page 17 explains why the CCA for Class 12 is only one half (page 14) of the capital expenditures on computer software (page 9) for 2011, while for the 2010 it is 100% of the expenditure.

a) Please provide confirmation that the elimination of the half year rule applies to computer software in Class 12. Please provide any information that indicates that the elimination of the half year rule applies to Class 12 and not just Class 50 (computers and systems software).

b) Please confirm that the computer software expenditures are properly included in Class 12 rather than in Class 50.

Response

a) The elimination of the half year rule only applies to systems software previously included in class 50, now class 52 for acquisitions after January 27, 2009 and before February 2011. The half year rule continues to apply to applications software included in class 12. Hydro One incorrectly applied the elimination of the half year rule to class 12. This will be corrected in our final rate order, resulting in the smart meter adder being higher than initially submitted by $0.01 (to $2.18) in 2010 and being lower by $0.58 (to $3.87) in 2011.

b) Computer software expenditures are properly included in class 50 (now class 52) and applications software is properly included in class 12. Please see Exhibit H, Tab 3, Schedule 18.

Energy Probe INTERROGATORY #37 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 2, Schedule 1

a) If rates cannot be in place for January 1, 2010, over what period does Hydro One propose to refund to customers the $25.8 million?

b) Hydro One states that it is proposing to establish a "Regulatory Asset Recovery Account" to track any difference between the amount of Regulatory Assets approved and the actual value of the Regulatory Assets detailed above as at December 31, 2009.
   (i) Will this account include the variance between the $25.8 million forecast for December 31, 2009 and the actual balance at December 31, 2009? If not, why not?
   (ii) Will this account track the variance between the $25.8 million forecast to be refunded to customers and the actual amount that is ultimately refunded to customers? If not, why not?

Response

a) If rates cannot be implemented January 1st, 2010, Hydro One proposes that the refund of the $25.8M (Rider #6) should coincide with the date change for future Distribution rates, which is currently expected to be January 1, 2012.

b)

(i) No, Hydro One will only post approved amounts to Regulatory Asset Recovery Account (Rider #6). Therefore any difference will remain in the applicable Regulatory Asset account for future settlement.

(ii) Yes, at the end of the Rate Rider period, a true up will be done to ensure the actual amount is refunded to customers.

Energy Probe INTERROGATORY #38 List 1

Interrogatory

Issue 6.1 – Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts appropriate?

Ref: Exhibit E1, Tab 1, Schedule 1, Attachment 1 &
Exhibit F2, Tab 1, Schedule 2

a) Does the disposition of the deferral accounts shown on line 4 of Exhibit E1, Tab 1, Schedule 1, Attachment 1 for 2010 and 2011 include the requested recovery of pending assets as shown in Exhibit F2, Tab 1, Schedule 2?

b) Please reconcile the figures for 2010 and 2011 shown in Exhibit E1, Tab 1, Schedule 1, Attachment 1 with the figures shown in Exhibit F2, Tab 1, Schedule 2.

c) Please identify the accounts that make up the figures provided in Exhibit E1, Tab 1, Schedule 1, Attachment 1 and the calculation of the amounts for each account.

Response

a) Yes, the disposition of the deferral accounts shown on line 4 of Exhibit E1, Tab 1, Schedule 1, Attachment 1 for 2010 of $11.9M and 2011 of $45.2M includes the requested recovery of pending assets as shown in Exhibit F2, Tab 1, Schedule 2.

b)

2010 Rider ($M)

Rider 6	
Rider 1	(11.5)
Retail Service Cost Variance Account	(1.0)
Retail Settlement Variance Account	(1.5)
Smart Meter Minimum Functionality up to Dec. 31, 2008	0.4
Smart Meter Exceeding Minimum Functionality up to Dec. 31, 2008	0.6
As per Exhibit F2, Tab 1, Schedule 2	**(12.9)**
Disposition of 2006 rate rider (RARA 2)	8.0
Disposition of 2008 rate rider (RARA 3)	(31.5)
Disposition of 2008 rate rider (RARA 4)	12.9
Disposition of 2009 rate rider (RARA 5)	4.3
Revenues from proposed smart meter adder	31.1
Total of Riders – As per Exhibit E1, Tab 1, Schedule 1, Attachment A	**11.9**

2011 Rider ($M)

Rider 6	
Rider 1	(11.5)
Retail Service Cost Variance Account	(1.0)
Retail Settlement Variance Account	(1.5)
Smart Meter Minimum Functionality up to Dec. 31, 2008	0.4
Smart Meter Exceeding Minimum Functionality up to Dec. 31, 2008	0.6
As per Exhibit F2, Tab 1, Schedule 2	**(12.9)**
Disposition of 2008 rate rider (RARA 3)	(10.5)
Disposition of 2008 rate rider (RARA 4)	4.3
Revenues from proposed smart meter adder	64.3
Total of Riders – As per Exhibit E1, Tab 1, Schedule 1, Attachment A	**45.2**

c) Please see Rider 6 in part b)

Energy Probe INTERROGATORY #39 List 1

Interrogatory

Issue 6.2 – Are the proposed new Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 2

a) Please provide the rationale for the pension cost differential account to track the difference between the forecast and actual pension costs.

b) Please provide the rationale for the OEB cost differential account to track the difference between the forecast and actual OEB costs.

Response

a) Please refer to response at Exhibit H, Tab 1, Schedule 117.

b) Please refer to response at Exhibit H, Tab 1, Schedule 118.

Energy Probe INTERROGATORY #40 List 1

Interrogatory

Issue 6.2 – Are the proposed new Deferral and Variance Accounts appropriate?

Ref: Exhibit F1, Tab 1, Schedule 2, page 2 &
EB-2008-0408 Report of the Board

a) Does Hydro One's application for 2010 and 2011 rates comply with the Filing and Reporting Requirements as set out in paragraphs 9.1.1 and 9.1.2 in the July 28, 2009 EB-2008-0408 Report of the Board Transition to International Financial Reporting Standards?

b) Has Hydro One used the existing CGAAP based regulatory accounting for 2010 rates?

c) Has Hydro One used the existing CGAAP based regulatory accounting for 2011 rates?

d) Is Hydro One seeking rates based on modified IFRS accounting for either of 2010 or 2011 rates?

e) For which years is Hydro One proposing that the account related to the impact of change in IFRS would apply?

f) Please explain fully what impacts would be recorded in this account.

Response

a) Yes, Hydro One's application for 2010 and 2011 rates complies with the Filing and Reporting Requirements as set out in paragraphs 9.1.1 and 9.1.2.

b) Yes, Hydro One used the existing CGAAP based regulatory accounting for 2010 rates.

c) Yes, Hydro One used the existing CGAAP based regulatory accounting for 2011 rates.

d) Hydro One is seeking rates based on CGAAP which, given the IASB's exposure draft on rate regulated accounting, has been assumed to result in no difference from modified IFRS for 2010 or 2011 rates.

e) Hydro One is proposing the account starting 2010.

f) Refer to Exhibit H, Tab 1, Schedule 119, part b.

Energy Probe INTERROGATORY #41 List 2

Interrogatory

Issue 1.3 - Is service quality based on the OEB specified performance indicators, acceptable?

Ref: Exhibit A, Tab 4, Schedule 1, pages 16-20

The Evidence in Section 6 - Reliability on these pages describes the company's reliability measurement indices SAIDI and SAIFI. The term "force majeure" is used to define an event that "impacts more that 10% of customers serviced by Hydro One Distribution".

a) Please explain how the 10% criterion was arrived at.

b) "Force majeure" is a legal term used in contracts to relieve parties from liability or the requirement to perform their obligations under a contract when specified events occur. These events are customarily understood to be outside the control of the parties. Is the use of this term in the company's reliability measurement system intended to convey an analogous condition ie. that these events are outside the company's control?

c) Do other utilities to which the company compares its reliability performance also use the term "force majeure" to segregate major events affecting reliability?

d) Lines 15-16 of Page 19 note that defective equipment accounts for 22% of SAIDI. Of this, 8% is attributed to force majeure defective equipment. While high winds and ice loading of trees is conceptually understandable in a force majeure context, defective equipment is not so obvious. Please explain

Response

a) Please refer to response at Exhibit H, Tab 1, Schedule 5 part b.

b) Typically, these are caused by events such as large storms or the August 2003 Eastern North America blackout, which are outside Hydro One’s control.

c) Please refer to response at Exhibit H, Tab 1, Schedule 5 part a.

d) Hydro One captures the cause for all interruptions under all conditions. The percentages indicate what types of interruptions occurred during Force and Non Force Majeure events. The percentages do not indicate that defective equipment was the reason for the Force Majeure; it just means that these types of interruptions occurred during Force Majeure events.

Energy Probe INTERROGATORY #42 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit A, Tab 4, Schedule 1, page 3, Table 1

Table 1 sets out the company's strategic objectives and five year vision. Under the category of Recruitment Knowledge Transfer the five year vision is to "achieve and maintain top quartile employee engagement". Please provide details of:

a) What does the company mean by "Recruitment Knowledge Transfer"?

b) What does the company mean by "employee engagement"?

c) What is meant by the "top quartile" of employee engagement?

d) How is the top quartile measured?

e) Where along this measurement continuum is the company presently situated in respect of employee engagement?

f) What specific actions are required to achieve top quartile performance in employee engagement?

Response

a) Recruitment knowledge transfer comprises a number of initiatives aimed at transferring knowledge from senior staff to our newest employees.

b) By engagement, Hydro One means the extent to which employees commit to someone or something in their organization, how hard they work, and how long they stay as a result of that commitment.

c) Top quartile employee engagement is the top quartile (75th percentile) of the Gallup overall company database.

d) see (c) above.

e) Hydro One is currently ranked at the 22nd percentile of the overall Gallup database.

f) In 2009, every work group at Hydro One has developed action plans based on their individual Gallup Survey results. Hydro One will be conducting the 2nd out of 3 annual surveys in October 2009 to measure progress from last years survey results.

Energy Probe INTERROGATORY #43 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit A, Tab 4, Schedule 1, page 3, Table 1

Another strategic objective in Table 1 is Productivity with the five year vision being to "achieve top quartile unit cost in Distribution".

a) Please provide details of the measurement criteria used for distribution costs.

b) Please provide details of the plans in place or to be developed to achieve top quartile performance.

c) What comparator distributors does the company compare its distribution unit costs to for the purposes of Productivity. Please provide any studies or analyses showing this comparison.

Response

a) Measurement criteria are focused on Distribution Capital and O&M per km of distribution lines using the following criteria in selecting utilities:
   1. Service Territory Size- More than 100,000 sq km
   2. Customer count- Between 500,000 and 3 million
   3. Customer density- Fewer than 30 customers per sq km
   4. Customers per distribution km – Less than 40 customers per pole km
   5. Regional Location- Some where chosen for proximity to Hydro One thus sharing weather conditions, others were chosen for similar vegetation density

b) Hydro One has initiated many programs to reach its goal of being “top quartile unit cost in Distribution”. A listing of several of these initiatives follows: (1) a shorter Vegetation Cycle is being adopted which should lead to reduced unit costs consistent with *2008 Vegetation Management Program Review* report filed as Part of EB-2007-0681 in Exhibit H Tab 1 Schedule 14; (2) a new Customer Communication Program called “Right Tree, Right Place” is being launched to better educate customers; (3) a Herbicide Pilot is being planned; (4) new equipment is being adopted for greater efficiencies; (5) greater use of information, for example Asset Condition Assessments, for better planning which allows for more work bundling

c) The comparisons will be with peer Canadian and US distribution utilities. The pool of distribution utilities can vary year over year depending on the participation of individual distribution utilities within the benchmarking community.

Energy Probe INTERROGATORY #44 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit A, Tab 4, Schedule 1, page 5

Lines 2-6 reference the company's service centers from which trouble call crews are dispatched.

a) Please provide a list of these service centers showing geographical location, number and type of staff assigned to each center and territory serviced by each center.

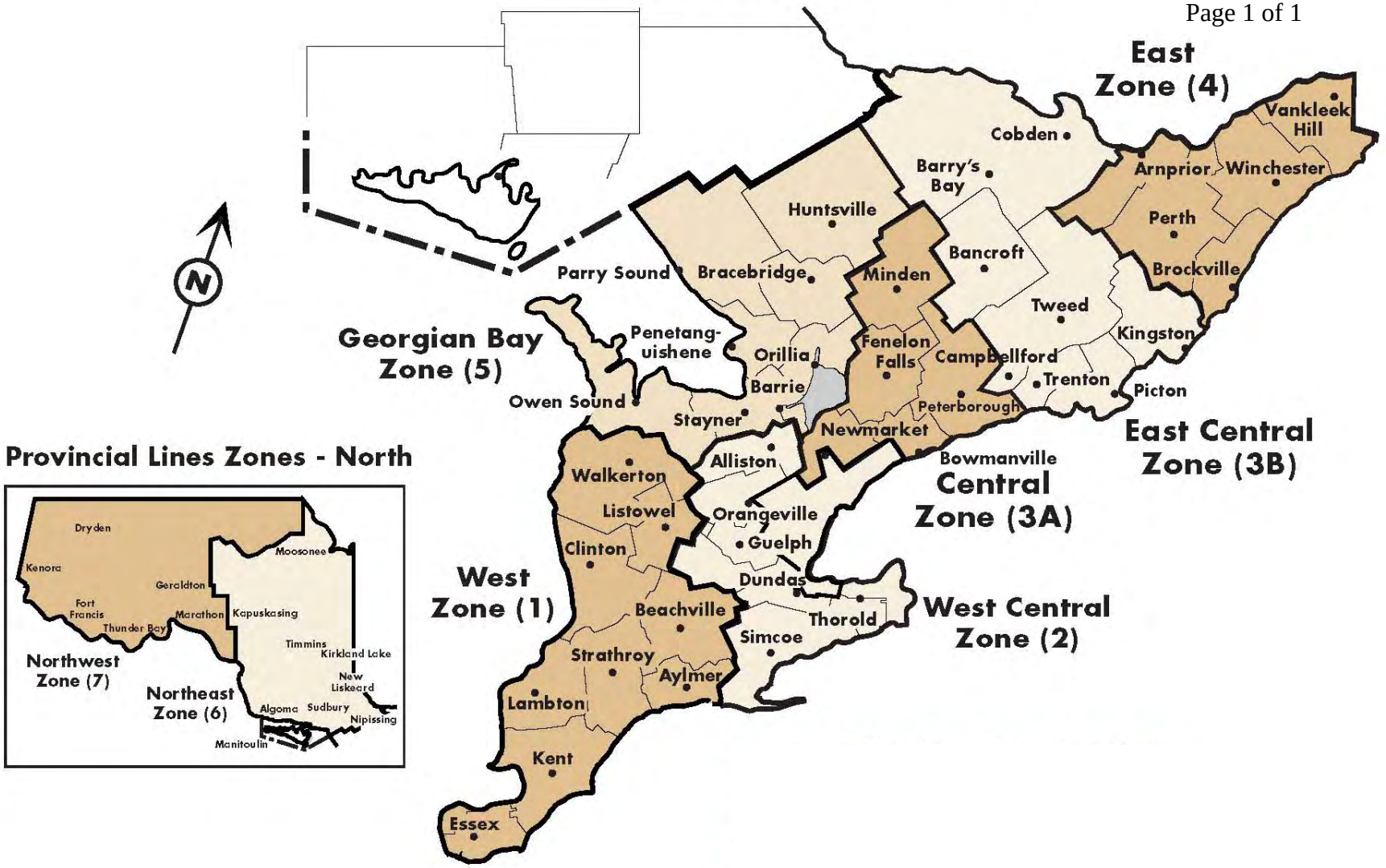
b) What is the organizational structure for managing these centers?

Response

a) The geographical location and territory serviced by Hydro One's service centers is shown in the attached map. The number of staff at each service centre ranges from 5 to 40 depending on the size of the territory serviced. The type of staff at each service centre consists of engineering technicians (ADETs), meter readers, Powerline technicians, union trade supervisors, and Front Line Managers in some work centres.

b) Hydro One service territory is divided into eight Distribution zones. Each zone has a Superintendent under which there are a number of Operations (OPS) managers. The OPS managers look after the staff described in part a) assigned to their service centre. Each Zone also has an On-call manager for after hours support to the field staff. The Superintendents report to the Director of the Provincial Lines organization.

Provincial Lines Zones - South



Provincial Lines Zones - North

Energy Probe INTERROGATORY #45 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit A, Tab 4, Schedule 1, pages 10 & 11

Lines 26-28 on page 10 and lines 1-3 on page 11 describe the time required for trouble call response on the company's system. Response time on the rural part of the system is noted as up to 4 hours due to travel requirements.

a) Do trouble crew staff receive full hourly wage rates for time spent traveling?

b) Are staff paid travel time from the time they leave their residence upon receiving a call out or from the time they arrive at the service center?

c) Does the company have any standards or requirements on how long trouble crew staff have to arrive at the service center after receiving a call out?

d) Does the company keep statistics or other records of how long it takes on average for trouble crew staff to reach a reporting center after receiving a call out? If so, please provide a summary.

Response

The interrogatory mentions “4 hours due to travel requirements”. Hydro One clarifies that the 4 hours does not refer to the time required for its on-call crews to get from their place of residence to the work centre. The 4 hour response time is due to significant travel required for the on-call crew to get to the location of outage due to the rural nature of Hydro One’s customer base, and the time required to get to the next trouble call location.

a) There is no provision for travel time when responding to trouble calls. Staff are paid from the time they leave home until the time they return home as per the terms of the Collective Agreement.

b) See response to part a).

c) The requirement for on-call work is for the staff to be available within 30 minutes of our Service Centre.

d) No.

Energy Probe INTERROGATORY #46 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, pages 5 & 6

Table 1, starting on page 5, tabulates changes to the collective agreement between Hydro One and the PWU over a number of negotiating periods. For the period April 1, 2001 - March 31, 2002 please clarify the following changes to the collective agreement:

a) Modified staff reduction plan
   i) How did the new plan differ from the previous one?
   ii) Is the new plan negotiated here still in effect in the current collective agreement?

b) Winter meal allowance
   i) What period did the previous winter meal allowance cover and what period did the new meal allowance period cover?
   ii) What was the stipend for meal allowance during the subject term and what is it in the current collective agreement?
   iii) Are employees required to submit receipts to claim this expense?
   iv) Which Hydro One employee classifications have the benefit of winter meal allowances?
   v) What is the rationale for paying winter meal allowance?
   vi) Does Hydro One know of other LDCs that pay winter meal allowance to their employees?
   vii) Is the reduced winter meal allowance period negotiated here still in effect in the current collective agreement?

c) Purchase Service Agreements
   i) What are Purchase Service Agreements?
   ii) What do the 14 PSAs referred to cover?
   iii) Are the PSA provisions negotiated here still in effect in the current collective agreement?

d) Hiring hall employees
   i) Who provides hiring hall employees with pension and other benefits?

ii) Does Hydro One provide any compensation to either the hiring hall directly or to the hiring hall employees to offset the cost of pension or other benefits?

e) Lines staff second shift
   i) What is meant by "renewed ability" to have line staff on second shift?
   ii) Was this the first instance of Hydro One negotiating a second shift for line staff?
   iii) Is Hydro One aware of other LDCs having second shifts for line staff?
   iv) Is the second shift provision for line staff still in effect in the current collective agreement?

Response

a)

i) The surplus staff procedure was modified to allow over complement staff to terminate with a severance prior to the company activating the corporate wide surplus procedure. This is advantageous because it saves a costly and time consuming exercise of displacing other staff.

ii) Yes

b)

i) The period of time where winter meals are allowed was reduced by two months. Commencing in 2001, winter meals were provided between December 1 and March 31st south of the French River and November 1 to April 30th for areas North of the French River.

ii) There has been no change in the amount of reimbursement for meals. Only the period of eligibility has been reduced.

iii) Yes

iv) Field Maintenance staff including Regional Maintainers – Lines and Forestry.

v) Field maintenance staff work outside and away from the work centers. The winter meal provision provides a warm meal during the cold winter months.

vi) We are not familiar with the practice of other LDC's with respect to winter meals.

vii) Yes

c)

i) Purchase Service Agreements (PSA's) are agreed upon decisions to use a contractor to perform work otherwise performed by PWU represented employees.

ii) The 14 Province wide PSA's include:

Janitorial work
Snow Removal
Grass Cutting and General Grounds Clean-up
Heavy Equipment Operator (Backhoe etc.)
Specialized Equipment Operator(Rock Drilling) etc.
Printing Services
Data Centre
Water Heater Maintenance, Installation and Removal
Office/Furniture Moves
Office Services provided by the landlord
First Nations Contractors working on and adjacent to First Nations Land where a significant majority of the contract work is on First Nations Land
Drive back and delivery services
Minor fleet maintenance
Minor office modifications

iii) Yes

d)

i) The PWU provide pension and benefits to hiring hall employees.

ii) Yes, Hydro One remits to the PWU amounts for benefits and pension. The PWU administers the pension and benefit funds for hiring hall employees. Hydro One has no on going obligation with respect to these pension or benefit plans.

e)

i) When the lines second shift was first introduced into the collective agreement, it was a limited term. In 2001 collective bargaining, the parties agreed to extend the pilot project for a further term.

ii) See e) i)

iii) Other LDC's do have a 2nd shift.

iv) Yes

Energy Probe INTERROGATORY #47 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit Cl, Tab 3, Schedule 2, pages 5 & 6

Table 1, starting on page 5, tabulates changes to the collective agreement between Hydro One and the PWU over a number of negotiating periods.

For the period April 1, 2002 - March 31, 2003 please clarify the following changes to the collective agreement:

a) Temporary Work Headquarters
   i) How did the new clause for temporary work headquarters differ from the previous one?
   ii) How is a temporary work headquarters defined?
   iii) What criteria must an employee meet to qualify for travel allowance to temporary work headquarters?
   iv) Do any employees asked to report to temporary work headquarters receive room and board? What determines who receives travel allowance and who receives room and board?
   v) Is the temporary work headquarters provisions negotiated here still in effect in the current collective agreement?

b) Lineperson second shift
   i) Is the permanent provision for lines person second shift still in effect in the current collective agreement?

c) Meter Reader B
   i) What distinguishes a Meter Reader B from any other meter reader position?
   ii) Is the lower cost Meter Reader B provision still in effect in the current collective agreement?

Response

a) Temporary Work Headquarters

i) The new clause established a set "per diem" for all costs associated with travel to and from temporary work HQ, including mileage, travel time, meals, etc. It is much easier for Managers to administer, ensures consistent application of travel payments and reduces the number of grievances regarding appropriate temporary work HQ payments to zero.

ii) a temporary work headquarters is the work location at which an employee is directed to work while carrying out his/her duties away from his/her regular work headquarters.

iii) An employee must be directed to report to a temporary work headquarters. The employee must commute daily and be present at the temporary work headquarters during their normal working hours (i.e. all travel is on their own time).

iv) If a temporary work headquarters is 50km or more from their regular work headquarters, the employee may elect to stay rather than commute daily. The employer can deny employees the right to commute daily if the commuting time is deemed excessive or extreme weather conditions exist.

v) Yes

b) Linesperson Second Shift

i) Yes

c) Meter Reader B

i) Please see Exhibit H, Tab 3, Schedule 58.

ii) Yes

Energy Probe INTERROGATORY #48 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, pages 5 & 6

Table 1, starting on page 5, tabulates changes to the collective agreement between Hydro One and the PWU over a number of negotiating periods.

For the period April 1, 2003 - March 31, 2005 please clarify the following changes to the collective agreement:

a) Streamlined staff reduction process
   i) What comprised the "streamlined staff reduction process" and how did it differ from the previous process?
   ii) Under what conditions could management "invoke" the streamlined process?
   iii) Has Hydro One taken advantage of this streamlined process? If yes, please describe how, when and what cost savings accrued?
   iv) Is the streamlined process negotiated here still in effect in the current collective agreement?

b) Hiring hall meter readers
   i) Prior to this direct call out procedure how were hiring hall meter readers acquired by the company?
   ii) If hiring hall meter readers were always available albeit by a different call out process, how was direct access to them an improvement?

c) On call for helicopter pilots and air engineers
   i) How were after hours requirements for helicopter pilots and air engineers managed prior to having them on call?
   ii) As on call payments are normally an incremental cost to no on call payments, how was the establishment of on call for helicopter pilots and air engineers a cost savings for the company?

d) Continue Temporary work headquarters provisions
   i) Was the original temporary work headquarters provision only a temporary provision?
   ii) If not, why did the provisions need to be continued in this agreement?

e) CMS shift work provisions
   i) What does CMS stand for?
   ii) Did this group previously not work shifts?
   iii) Why was a mid term agreement necessary to establish shift work for this group?
   iv) Is the provision negotiated here for CMS shift work still in effect in the current collective agreement?

f) Health and Dental cost study
   i) What was the outcome of the joint review of health and dental costs?
   ii) Was a report prepared by the team? If so, please provide a copy. If not how were recommendations made to management? What were they?
   iii) Were any of the recommendations implemented by the company?
   iv) What were the estimated savings?

Response

a)

i) Hydro One gained the ability to invoke a modified layoff/termination process. The previous process involved all PWU employees in Hydro One. The streamlined process only involves the small number of impacted employees. Restricting the number of employees involved reduces the cost and time to run the process and also minimizes the negative disruption associated with running a full layoff/termination process.

ii) The number of employees to be laid off/terminated must be 40 or less.

iii) It has not been used to date as we have been able to accommodate situations where we have too many staff through redeployment to other work locations.

iv) Yes, it remains in effect.

b)

i) The Company would put in a requisition to the PWU Hiring Hall, who would have reviewed the requisition and then put out a call for workers. Ideally, three days prior to the start date, the PWU Hiring Hall would send the list of referrals to Hydro One's Workforce Acquisition department. Providing no issues were identified, referrals would be sent out to work on the start date. They would go through the sign on procedure, and complete any required training.

ii) The previous process did not allow Hydro One to meet immediate staffing needs. It always took a number of days, and Hydro One had no guarantee of getting employees that could start work without any additional training. Under the direct

call out procedure, the PWU provides a list of Hiring Hall Meter Readers that can be called out to work on short notice and without first contacting the PWU Hiring Hall Business Representative. This enables Management to address short notice understaffing situations immediately and thereby increase the ability to read meters within the 4 day cycle window.

c)

i) Prior to having the on call provisions, the collective agreement provided management with two options: either call employees and ask them to work when after hours work was required and hope they answered/agreed to work, or, place employees on standby and pay them premium pay for all hours that they held themselves available even if they didn't work. Management did attempt to try another informal approach however, that was grieved as it was viewed as being outside the collective agreement.

ii) The previous option was to pay standby for all hours the person kept themselves available. The implementation of on-call allowed the company to have the workers available for a minimal cost, which is only half an hour's pay per weekday, and an hour's pay for Saturdays, Sundays, and statutory holidays.

d)

i) The temporary work headquarters provisions that were introduced in 2002 were to expire on March 31, 2003. Through collective bargaining in 2003, these provisions were extended to March 31, 2005.

ii) N/A

e)

i) Central Maintenance Shops, which are located in Pickering, Ontario

ii) The limited provisions for this group to work shifts were set to expire on March 31, 2003, and therefore required renewal to remain in effect.

iii) The parties often document specific items as mid term agreements if the provisions of the agreement only apply to a limited group of employees, which is the case with CMS.

iv) Yes, the midterm agreement establishing CMS shift work is still in effect and all mid term agreements form part of the collective agreement.

f)

i) The committee discussed a number of administrative and educational issues, however, no actual changes were made to the level of health and dental benefits provided to employees as that was outside the committee's mandate and can only be achieved during bargaining.

ii) See i)

iii) See i)

iv) See i)

Energy Probe INTERROGATORY #49 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, pages 5 & 6

Table 1, starting on page 5, tabulates changes to the collective agreement between Hydro One and the PWD over a number of negotiating periods.

For the period April 1, 2005 - March 31, 2008 please clarify the following changes to the collective agreement:

a) PWD annual incentive plan
   i) How long was the incentive plan in operation before being cancelled?
   ii) How much did the plan cost over its lifetime?
   iii) Is Hydro One aware of any other Ontario LDCs that make incentive plan payments to its unionized employees? If so, please provide whatever details the company has.
   iv) What did the PWD get in return for agreeing to drop the incentive plan?
   v) Does the current collective agreement have any incentive plan provisions for unionized employees? Does Hydro One have any incentive plan outside the collective agreement that applies to any unionized employees?

b) Three day weekend shift for lines
   i) How did the new shift provisions differ from the old provisions?
   ii) Why was it necessary to make a three day weekend shift when weekends are ordinarily only two days long?
   iii) How did this new provision reduce costs for the company?
   iv) Is this provision for a three day weekend shift for lines still in effect in the current collective agreement?

c) Switching agent classification and midnight shift
   i) What is a switching agent?
   ii) How did this lower costs compared to previous arrangements for switching?
   iii) What is the significance of the midnight shift? Ie. why is there any switching in the middle of the night? How was it previously attended to?
   iv) Is the provision negotiated here still in effect in the current collective agreement?

d) Afternoon shift for fleet mechanics
   i) How did this provision compare to previous provisions for shift work in this group?
   ii) How did this improve cost efficiency?
   iii) Is the provision negotiated here still in effect in the current collective agreement?

Response

a)

i) The PWU Incentive Plan was started on July 1, 2000 and operated for the later half of 2000 plus all of 2001 through 2004 inclusive. It was terminated in 2005 and there was no payout that year.

ii) $27M for the four and a half years that it operated.

iii) Not aware

iv) The cancellation of the PWU Incentive Plan was only one part of the overall agreed upon terms of the 2005-2008 Collective Agreement. It is impossible to specify any particular item that the PWU gained as a result of its cancellation. The overall package of agreed upon items was approved by both parties.

v) The current PWU collective agreement does not have an Incentive Plan nor are there any incentive plans outside the terms of any of Hydro One's collective agreements.

b)

i) There was no 3-day weekend shift provision previously and therefore all work on weekends was paid at overtime rates.

ii) The three-day shift involves 3 shifts of 10 hours each and those 30 hours are the employee's work week.

iii) Without the weekend shift language most of the hours would be worked at premium rates. Previously, employees would have received 51 hours of pay (Friday 8 hours straight time plus 2 hours at 1.5 time plus Saturday and Sunday at 10 hours double time each day) for the 30 hours that Hydro One now pays 40 hours.

iv) Yes

c)

i) A switching agent goes into field locations and switches (isolates) electrical equipment so that other work groups can work on the equipment safely. Switching is often done before the day shift in order to maximize the time that the other work groups can work on the equipment.

ii) Previously, a higher paid tradesperson or technician would perform the switching duty. In addition, if the switching was done before the day shift, overtime rates would be paid to the tradesperson or technician. The new switching agent is paid at a lower base rate and does not attract premium pay for work performed on the night shift.

iii) By performing the switching during the midnight shift, the equipment is ready for the other work groups to work on during day shift when they are paid straight time rates. Previously, a higher paid tradesperson or technician would perform switching duties at premium overtime rates.

iv) Yes

d)

i) There was no provision that allowed the work to be performed at straight time rates during the hours in question.

ii) Allowed employees to work the afternoon shift on straight-time as opposed to overtime. Allowed work peaks to be accomplished on straight-time. Also allows vehicles to be repaired during the afternoon and therefore be ready for use by the work crews the next morning.

iii) Yes

Energy Probe INTERROGATORY #50 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit Cl, Tab 3, Schedule 2, pages 5 & 6

Table 1, starting on page 5, tabulates changes to the collective agreement between Hydro One and the PWU over a number of negotiating periods.

For the period March 31, 2008 - March 31, 2011 please clarify the following changes to the collective agreement:

a) Greater flexibility for University and College students
i) How did this provision compare to previous provisions for hiring university and college students?
ii) How did this provision improve cost efficiency for the company?

b) Security clearances for new hires
i) How did this provision differ from the previous practice regarding security clearances for new hires?
ii) What prompted the need for a security clearance for new hires?
iii) What investigation of a prospective hire's background is conducted?
iv) How does this provision result in better cost efficiency for the company?

c) Pre hire assessment tool for apprentices
    i) How did this provision differ from previous practices to assess candidates for apprenticeships in the company?
    ii) Why was it necessary to negotiate this practice with the union to assess individuals who are not yet company employees or union members?
    iii) How did this provision improve cost efficiency for the company?

d) Threshold for post retirement benefits
    i) How did this provision differ from previous provisions regarding post retirement benefit qualification?
    ii) How does this new threshold compare to other Ontario LDC post retirement qualification thresholds?
    iii) What are the estimated cost savings attributable to the new provisions?

Response

a)

i) Before this change, Hydro One had only the option of hiring for either a 4 or 16 month work term. This change allows Hydro One to hire university and college students for any length of time between 4 and 16 months.

ii) With greater flexibility in work terms, Hydro One has access to a greater number of University and College programs.

b) Correction: the security clearance has been introduced for existing staff, not new hires. Security clearances for new staff already existed.

i) Previously, Hydro One did not perform security clearances for existing Hydro One employees.

ii) Regulatory requirements as mandated by the Independent Electricity System Operator (IESO) require Hydro One to comply with NERC Cyber Security Standards. In those standards are requirements for personnel risk assessments (security clearances) for all persons who have either physical or electronic assess to critical cyber assets (CCA). There are no grandfathering provisions in these NERC standards therefore existing staff who have this CCA access require personnel risk assessments to be completed.

iii) The security clearance will review the employee's criminal record.

iv) No cost efficiencies gained.

c)

i) Before the Apprentice Assessment tool was negotiated with the PWU, the parties manually assessed thousands of applications for the various trades apprentice vacancies.

ii) The apprentice hiring is a joint hiring process with the PWU. Any change in recruitment practice would require joint agreement. Trades apprentices are part of the PWU hiring hall until such time as they become regular employees.

iii) The trades assessment tool will have behavioral questions that will facilitate the ranking of candidates. The assessment tool will be first used in first quarter 2010 but it is anticipated that with a more rigorous assessment tool, better selections will result in the selection of the best available candidates.

d)

i) Before this change, pensioners and surviving pensioners who remarried could add dependents.

ii) We are not familiar with the practice at other LDC's with respect post retirement benefits.

iii) The savings will depend upon factors too difficult to determine but this change does limit liability by not allowing new dependents for remarried pensioners or surviving pensioners.

Energy Probe INTERROGATORY #51 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit Cl, Tab 3, Schedule 2, page 9

Lines 20-22 report that Networks work program is expected to increase by 33% over the 2009-2011 period while regular staff is expected to increase by only 16%. Table 3 on the same page shows base payroll over the same period increasing from $543.9 M to $791.8 M, an increase of approximately 45%.

Please explain why base payroll costs should be increasing by 45% when staff is only expected to increase by 16%.

Response

The base payroll costs include wages for regular, temporary and casual construction employees. The 16% increase in staff over this time period is only for regular employees. Exhibit H, Tab 7, Schedule 67 shows the breakdown by employee groups and regular or temporary/casual staff.

Energy Probe INTERROGATORY #52 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, page 9

On lines 24-25 the company reveals its goal of "reducing overall wages, pension and benefits for future new hires":

a) Has the company made any agreements with the PWU to achieve this goal? If yes, please describe the agreements?

b) If no, how far in the future does the company expect such agreements to be made?

Response

a) Please refer to response at Exhibit H, Tab 10, Schedule 39.

b) The labour strategy for the next round of PWU bargaining has not been established at this time.

Energy Probe INTERROGATORY #53 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, page 10

On lines 5-6 the statement is made that "several management staff have left the company in recent years".

a) What does Hydro One consider to be normal turnover in its employee base?

b) The word "several" implies 2 or 3 people have left the company. Does Hydro One consider this a serious drain of its resources given the number of management staff employed?

c) Was Hydro One able to recruit replacements for the management staff that left?

d) Why does Hydro One believe it must only recruit "the top people"? How does it distinguish "top people" from the pool of otherwise competent people?

e) In Hydro One's view, does attracting "top people" depend primarily on offering the highest compensation?

Response

a) The rate of turnover or attrition will change from year to year. Hydro One would expect an attrition rate between 2% and 4% . In 2008, the attrition rate for regular staff was 3.5%.

b) In 2007 and 2008, 23 and 25 MCP regular employees left Hydro One respectively. Yes, this would be a serious drain of MCP resources since experienced staff are not easily replaced given the tight labour supply facing the electrical industry.

c) For the majority of staff who left, replacements have been found. However, these replacements would typically have a learning curve as they move into these new roles.

d) Hydro One provides an essential service to the Province of Ontario. Employees work in a very complex and often dangerous work environment. Given this, it is important

that the best possible external applicants are attracted. The demographic challenge facing Hydro One also presents an opportunity to recruit 'top' employees to further the effort to nurture the continuous improvement culture at Hydro One.

e) Hydro One does not want to attract 'top people' if their only interest is compensation.

Energy Probe INTERROGATORY #54 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit Cl, Tab 3, Schedule 2, page 11, Lines 9-12

These lines describe Hydro One's ability to acquire trades skill comparable to its own regular staff, "when appropriate", from a union hiring hall at reduced cost because no pension or other benefits are paid.

a) What are the "appropriate" conditions under which Hydro One can take advantage of this option?

b) As a percentage of total skilled trades staff, how many hiring hall employees does the company employ on average during the year?

c) Are there limits in the collective agreement with the PWU for the use of this option?

d) If skilled trades staff are available from the hiring hall, why does Hydro One need to expend the time, effort and money to rebuild its aging workforce as referred to in lines 1-3 of page 10 and elsewhere in the evidence.

Response

a) The Hiring Hall enables Hydro One to supplement the regular workforce with a mobile and contingent workforce to perform seasonal and supplemental trades maintenance work.

b) Approximately 30% of PWU trades work is performed by Hiring Hall staff.

c) The PWU collective agreement specifies which trades may be resourced from the Hiring Hall.

d) The purpose of the Hiring Hall is not to replace the regular workforce. If Hydro One determines an on going vacancy exists, there are contractual requirements to use regular staff. Hiring hall staff are used mostly for a specific skill while the regular trades use their multi skilled training to perform more complex work.

Energy Probe INTERROGATORY #55 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit Cl, Tab 3, Schedule 2, page 11, Lines 14-23
Exhibit Cl, Tab 3, Schedule 2, page 12, Lines 1-5

In line 16 reference is made to "multi skilled employees". An example is cited as "Regional Maintainer - Lines, Mechanical or Electrical".

a) Please clarify what is intended by the words "Mechanical or Electrical" i.e. does this refer to mechanical and electrical components of a RML's work; or does it refer to Regional Maintainer - Mechanical Mtce and Regional Maintainer - Electrical Mtce; or does it mean Regional Maintainers Lines are also qualified to perform the work of Mechanical and Electrical Maintainers normally working on stations?

b) If the reference is to a RML's work components, is the company suggesting that its' line staff is multi skilled because they perform both mechanical and electrical work on lines?

c) What comprises the mechanical and electrical components of the line maintainer's work and how do they differ from the work of an LDC line maintainer's work?

d) The reference in line 19 to LDC work being "typically based-on dry land" suggests that Hydro One's work is not based on dry land. Please explain.

e) What comprises the "varied landscapes that exist at Hydro One" referred to in lines 19-20? How does this make a line maintainer's job more difficult or require greater skills than an LDC line maintainer?

f) What comprises the "off road equipment" referred to in line 21? Why does this make a line maintainer's job more difficult or require greater skills than an LDC line maintainer?

g) Is the inclusion of CVOR equipment in line 21 as a differentiating feature of Hydro One line maintainers intended to suggest that LDC line staff do not have commercial vehicle operator registration? If yes, please explain the basis for this

conclusion. If no, why is CVOR included as a differentiating characteristic for Hydro One line maintainers?

h) Lines 21 and 22 state that RMLs can work on both distribution and transmission lines. What proportion of Hydro One's line maintainers are qualified to work on both distribution and transmission lines?

i) Line 21 states that RMLs can work on "overhead, underground and submarine cables". Is this intended to suggest that LDC line maintainers do not work on overhead, underground and submarine cables? If so, what is the basis for that conclusion? If not, why is this presented as a differentiating characteristic of Hydro One line maintainers?

j) Line 1 on page 12 refers to live line work performed by RMLs. Is Hydro One suggesting that LDC line maintainers do not work on live lines? If so, what is the basis for that conclusion? If not, why is it included as a differentiating characteristic of Hydro One line maintainers?

k) Lines 7-10 on page 12 describe how some work at Hydro One is assigned to lower rated classifications than at LDCs. Please provide evidence for this statement.

Response

a) The reference to 'multi skilled employees i.e. Regional Maintainer - Lines, Mechanical or Electrical is meant to provide examples of 3 separate multi skilled positions – RM- Lines, RM- Electrical and RM- Mechanical that exist at Hydro One.

b) No. A Regional Maintainer – Lines is considered multi skilled because in addition to the core duties of a Powerline Maintainer (perfoming a range of mechanical and electrical duties), the RM- Lines will also perform lead hand, work protection, contract monitoring, troubleshooting, technical, environmental, customer service and chainsaw duties.

c) See b) above

d) Hydro One RM- Line staff work on land but in addition, they are required to work in and around swamps, lakes, working off barges and boats. Unique to Hydro One is the fact that our RM- Lines work in the air off a helicopter. Hydro One is the only utility that performs work off the Air Stair platform. Working in the air as our crews do is something that typically LDC staff are not trained to do. Such work requires special training in order to work in a safe manner.

e) See d)

f) Given the variety of landscapes Hydro One staff work in, RM- Lines need to be aware and be able to operate a variety of equipment to access work locations. Since work is not often located just off the road like it is with other LDC's, Hydro One RM-Line staff often do not have the mechanical means like a crane to perform their work. As such, Hydro One staff need to be trained and competent in a variety of other rigging methods to accomplish the work.

g) Any operation of a vehicle over 4600 kg requires a CVOR certificate so other LDC's would have similar requirements.

h) Approximately 45% of Regional Maintainer – Lines are equally proficient on our Transmission and Distribution assets. All other Regional Maintainer – Lines have basic transmission training.

i) LDC staff would work on overhead and underground cables. To a lesser extent, they may work on submarine cables. Hydro One RM- Lines staff are qualified and are required to work on overhead, underground and submarine cables at any given time. As such, staff must keep their skill level current so they can work on any type of these cables. Submarine cables are a particular challenge since the work typically involves laying a large amount of cable and trenching and moving heavy equipment under inhospitable conditions.

j) LDC staff would do live line work on the systems they work on. Hydro One RM-Lines staff are qualified to perform live line work on the 2400 v to 500 kV systems. LDC staff would not work on live line at the high voltages Hydro One staff work on. Specialized training and experience is required to perform live line work on the 500 kV line.

k) The basis for this statement is information provided by Hydro One Lines staff who are familiar with LDC operations.

Energy Probe INTERROGATORY #56 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, page 12

In lines 24 to 27 the company proposes that the Board evaluate the prudency of Hydro One's collective agreements by considering "the history of gains made through collective bargaining". In lines 25 to 27 the company suggests that this approach is valid because benchmarking compensation levels to other utilities is also subjective.

a) Please explain why comparing compensation for similar positions in other utilities is a subjective exercise.

b) If benchmarking is a subjective exercise, why, in Hydro One's view, do so many companies engage in it to measure their performance?

c) Does Hydro One now take the view that the Mercer study on compensation levels is not a relevant comparison?

Response

a) As Hydro One stated in Exhibit C1, Tab 3, Schedule 2, page 12, “comparing Hydro One compensation levels to other utilities with different histories and facing different challenges and responsibilities” is subjective by its very definition.

b) Hydro One’s view is that benchmarking, despite its shortcomings, is a valuable tool and continues to utilize it as many other companies do.

c) The Mercer study on compensation is relevant but it is not the only relevant information that the Board should consider. Bargaining gains should be considered, as these gains are no less objective than benchmarking studies. Both have their shortcomings but nonetheless offer valuable insight as to the progress Hydro One is making. The history of collective bargaining does assist in assessing the reasonableness of the collective agreements. The analysis found at Exhibit C1, Tab 3, Schedule 2, page 14-16 is also useful to compare progress at Hydro One against the successor companies.

Energy Probe INTERROGATORY #57 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit Cl, Tab 3, Schedule 2, page 13

In lines 3 - 5 the company proposes comparing wage scales for "similar PWU and Society classification in the Ontario Hydro successor companies".

a) Why should compensation for positions at power generating companies be comparable simply because they use a similar nomenclature for categorizing positions?

b) Why is it not more relevant to compare Hydro One positions to similar positions with similar work in other utilities?

Response

a) Positions at OPG or Bruce Power are more comparable for reasons other than just similar nomenclature to categorize positions. The field trade positions listed in Exhibit C1, Tab 3, Schedule 2, page 14 were deemed both by the company and the PWU as equal classifications when Ontario Hydro existed. For instance the Regional Maintainer – Mechanical at Ontario Hydro performed work on the Transmission system (Hydro One) and in Fossil Stations (now OPG). At Ontario Hydro, the wage rate was identical. Since the demerger of Ontario Hydro the same classification is paid substantially more at both OPG and Bruce Power.

b) In Ontario, there is no other utility similar to Hydro One. While there are large utilities such as Toronto Hydro, London Hydro or Ottawa Hydro, none of these utilities match the size and complexity of the work performed by Hydro One employees. There are large Transmission and Distribution Utilities in other provinces, and while these companies would be relevant comparators, the reality is that Hydro One competes for staff and is vulnerable to losing experienced employees more so in Ontario. As such, the compensation at the successor companies is more relevant.

Energy Probe INTERROGATORY #58 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, page 17

On lines 16-17 the following statement appears " ... overall costs have been minimized by the simplification of required job skills and pay levels where appropriate."

a) Please provide some examples of the "simplification of required job skills" referred to in this quote?

b) What is meant by the "simplification ... of pay levels"? Please provide some examples of this.

Response

a) The introduction of the Meter Reader B and the Switching Agent allowed Hydro One to simplify jobs at the same time as reducing costs. The Meter Reader B does not perform the higher skills of meter installation, verification, or disconnects. The Switching Agent classification was created to have a dedicated resource who only performed switching duties. Previously, the higher skilled Regional Maintainer or Technician would perform switching duties.

b) As a result of creating these new classifications, a lower wage rate was established.

Energy Probe INTERROGATORY #59 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, page 17, Lines 21-26

In these lines, the company states that its ability to restrict compensation is affected by its need to compete for skilled workers with OPG, Bruce Power and the IESO.

a) Do any of OPG, Bruce Power or the IESO employ Regional Lines Maintainers?

b) Do OPG or Bruce Power employ power system control room operators?

c) Has Hydro One encountered any difficulty recruiting apprentices to any of its trades classifications?

Response

a) No. OPG and Bruce Power do have classifications that are comparable to classifications at Hydro One. Please see Exhibit C1, Tab 3, Schedule 2, page 14-15.

b) No

c) No

Energy Probe INTERROGATORY #60 List 2

Interrogatory

Issue 3.5 - Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref: Exhibit C1, Tab 3, Schedule 2, Appendix A

Pension costs are reviewed in this appendix.

a) Does Hydro One have any plans to alter its' pension benefit for future hires from defined benefit to defined contribution?

b) In the current defined benefit plan or in any retirement compensation arrangement plans, does Hydro One offer any employees more pensionable service years than the number of actual years worked? (e.g, the so called 2 for 1 or 3 for 1 arrangements provided to one or more prior executives). If yes, please provide details including the positions in the company that qualify for this additional pensionable service.

Response

a) No.

b) No.

Energy Probe INTERROGATORY #61 List 2

Interrogatory

Issue 9.2 - Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and OM&A budgets.

Ref: Exhibit A, Tab 4, Schedule 1, page 4

Lines 18-22 describe the OPA's RESOP program as having resulted in approximately 2300 new generation projects under 10 MW that could potentially connect to Hydro One's distribution system. The statement is made that "it is expected that many of these will go forward and connect to the system".

a) What is the total proposed capacity of these 2300 projects in MW?

b) Please provide a breakdown of these projects by renewable energy category ie, wind, solar, biomass, hydroelectric.

c) What is the basis for the assumption that many of these projects will "go forward and connect to the system"?

d) Over what time frame does the company expect these connections to occur?

Response

a) The 2300 projects that could potentially connect to Hydro One's distribution system add up to a total of 19,843 MW. It is known that some of these projects are duplicates, but Hydro One cannot tell the extent of duplication among these applications as proponents used different names.

b) See response at Exhibit H, Tab 3, Schedule 63.

c) The basis for the assumption that many of these projects will go forward and connect is the fact that much of the allocated capacity is at stations which have desirable locations for the renewable generation projects. Even though one specific project may withdraw or not fulfill its obligations under the Distribution System Code to maintain its allocated capacity, it is expected that this project would be quickly replaced by another similar project that applies for the same capacity.

d) Hydro One cannot forecast the time frame that these connections are expected to occur, as the connection process and in-service dates, especially prior to the recent amendments to the Distribution System Code related to the generation connections process, were controlled very much by the proponents.

Energy Probe INTERROGATORY #62 List 2

Interrogatory

Issue 9.2 - Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and OM&A budgets.

Ref: Exhibit A, Tab 14, Schedule 2, page 5

Lines 20-22 state:

> Hydro One's corporate strategy drives the Plan's vision for a conservation-oriented and more environmentally-conscious culture.

Please provide the meaning of this quotation.

Response

Hydro One's corporate strategy consists of four key strategic drivers of Innovation, Stewardship, Excellence and Safety. Key initiatives to upholding these drivers include investing proactively in distribution infrastructure to enable major additions of renewable distributed generation in a timely manner and seeking ways to leverage new technologies and knowledge from international organizations to reduce Hydro One's carbon footprint and improve overall system performance. Hydro One advances these initiatives through its Green Energy Plan which aims at incorporating renewable energy generation, developing Hydro One Distribution's Smart Grid and effectively promoting energy conservation to its customers. The Plan aims at adopting a more conservation-oriented and environmentally-conscious approach to system planning by investing in more CDM programs, once the *Green Energy and Green Economy Act* objectives with respect to CDM are operationalized, and by facilitating the connection of renewable distributed generation in the Province.

Energy Probe INTERROGATORY #63 List 2

Interrogatory

Issue 9.2 - Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and OM&A budgets.

Ref: Exhibit A, Tab 14, Schedule 2, page 6

The chart on this page summarizes projects resulting from RESOP that have requested Connection Impact Assessments (CIA). The total number of CIAs to the end of April 2009 is noted in column 2 as 1553. Comparing the number of CIAs in this chart to the number of possible projects referenced in Exhibit A, Tab 4, Schedule 1, page 4 (2300) indicates that about 67% of possible projects progress to the CIA stage. Of these 645 or 42% are outside the company's distribution connection threshold criteria leaving about 908 projects that qualify for connection to the distribution system (the "eligible projects"). This comprises about 39% of possible projects.

a) Does Hydro One agree that 39% of possible projects represents a reasonable maximum for the number of projects that might have to be connected to the distribution system?

b) Of the 908 projects that could be connected to the distribution system, 869 are noted as having CIAs completed but only 127 of these have connection agreements completed. This represents about 14% of eligible projects and 5.5% of possible projects. Does Hydro One agree that 5.5% of possible projects is a reasonable estimate of the projects that will ultimately be connected to the distribution system?

c) What is the total capacity for the 908 projects that are eligible for connection to the distribution system?

d) What is the total capacity for the 127 projects that have connection agreements completed?

e) For those projects that fall outside the distribution connection threshold, how many does Hydro One estimate will be connected to the transmission system? Please explain the basis for the estimate provided.

Response

a) The 2,300 possible projects referenced in Exhibit A, Tab 4, Schedule 1, page 4 refers to the number of CIA applications and IFA applications. The CIA application is an application to connect a generator the distribution system; the IFA is a request for

information for a project. Of the 1553 CIA applications, 908 were eligible for connection, meaning that there was capacity for them to connect to the existing distribution system. This shows that there was existing capacity on the distribution system to connect 58.5% of the CIA applications.

Technology		CIAs
Hydraulic Turbine	Number of Projects	70.0
	Sum of Proposed Total Capacity (MW)	324.9
Other (CHP, Biomass, Diesel, Gas)	Number of Projects	119.0
	Sum of Proposed Total Capacity (MW)	632.3
Solar	Number of Projects	463.0
	Sum of Proposed Total Capacity (MW)	4211.2
Wind Turbine	Number of Projects	711.0
	Sum of Proposed Total Capacity (MW)	6450.9
Total Number of Projects		**1363**
Total Sum of Proposed Total Capacity (MW)		**11619**

b) No, Hydro One does not agree that 5.5% of possible projects is a reasonable estimate of the projects that would ultimately be connected to the distribution system. It only represents the proportion of generator projects that, under the Distribution System Code existing at the same time, had progressed to the stage where they had an executed connection agreement. Hydro One believes that the recent amendments to the Distribution System Code for the generation connections process will facilitate getting generators to the stage where they will execute a connection agreement.

c) Partway through July 2009, Hydro One had completed 908 CIAs. These 908 CIAs cumulatively make up over 5,820MW.

d) 998 MW of generation cumulatively.

e) Hydro One cannot estimate how many of the projects that fall outside the distribution connection threshold will be connected to the transmission system. The decision to connect to either the distribution or transmission system rests with the proponent and not the Distributor nor the Transmitter.

Energy Probe INTERROGATORY #64 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 2, page 5

Table 2 shows Planned Station Maintenance expenditures in 2009 at $13.5 M which is close to the average spent per year in the previous three years.

a) How much PCB testing of stations equipment was done in 2009?

b) If Environment Canada regulations require removal of 500 ppm PCBs by 2009, why was there not a greater emphasis by Hydro One on testing in 2008 and 2009?

c) What penalties is Hydro One subject to if it fails to meet the removal deadlines set out in the Environment Canada regulations?

Response

a) PCB testing will take place in 2009 on stations that have been scheduled for planned maintenance outages. These tests will leverage the previously planned outages and will enable testing to proceed at a minimal cost, which is why the costs for PCB testing is not appreciable during 2009.

b) The new regulations were passed in September of 2008 at which time it was recognized by both Hydro One and Environment Canada that addressing PCBs in the stations environment would take a multi-year effort. Achieving the 2009 deadline was unattainable due to the complexities involved and the need to take station outages to enable PCB-related work. Given the reality of the situation, Hydro One applied to Environment Canada for an extension to the 2009 end-of-use deadline in accordance with the provisions under Part 2, Section 17 of the PCB Regulations. The extension requested is to allow the continued use of greater than 500 ppm PCB equipment until December 31, 2014. As a result, Hydro One Distribution did not place greater emphasis on testing in 2008 and 2009 and is planning an aggressive increase in PCB activities beginning in 2010.

c) The compliance and enforcement penalties that could be assessed against a company in the event of an alleged violation of the PCB Regulations are varied and would be determined on an incident-specific basis.

The PCB Regulations are under the Canadian Environmental Protection Act (CEPA) 1999 and as such the associated CEPA Compliance and Enforcement Policy would be applied when verifying compliance with the Regulations. The Policy sets out a range of possible responses to alleged violations, which may include: warnings, directions, environmental protection compliance orders, ticketing, ministerial orders, injunctions, prosecution, and environmental protection alternative measures.

Energy Probe INTERROGATORY #65 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 2, page 8

Lines 17-28 describe PCB testing requirements for stations transformer bushings. This is reported to be a "very time consuming process (i.e. several days)" partly because of the need to transfer load to a mobile substation before a transformer outage can be taken.

a) The evidence discusses transformer bushings. Have all station transformers been tested for PCB content?

b) What is the procedure for taking an oil sample from a transformer bushing?

c) Is there any correlation between PCB content in transformer insulating oil and the oil in the transformer bushings? i.e. is it possible to infer the PCB content of bushings by analyzing the PCB content of oil in the main tank?

d) What percentage of distribution stations have two transformers?

e) For two transformer stations, is it possible to run the station on a single transformer while the other one is tested rather than installing an MUS i.e. by doing the testing during low load times of the year?

f) Are there any records from manufacturers to assist in determining which transformer bushings contain more than 500 ppm PCB in the insulating oil?

g) When did manufacturers cease using oil containing PCBs? How many of the 1005 distribution and regulating stations transformers were purchased after that time and can be assumed to be PCB free?

Response

a) No. Page 22 of Exhibit D1, Tab 2, Schedule 1 outlines the percentages of station transformers and bushings that have been tested.

b) The procedure is as follows:

1. A transformer outage is taken and the transformer is taken out of service. Proceed to step 2 or step 3 below.
2. If the bushing has a sampling port, then an oil sample is extracted by way of the port.
3. If the bushing does not have a sampling port, then an oil sample is not easily extracted and the bushing is removed from the transformer and replaced.

c) No. The transformer main tank and bushing oil reservoirs are separate and not interconnected for the vast majority of transformers. A very small percentage of transformers within Hydro One Distribution's fleet do have an interconnected reservoir, where the bushing shares the transformer oil. In these limited situations, the PCB oil test would be representative of both the transformer and bushing oil.

d) Approximately 3%.

e) Yes, it is possible. However, the possibility depends upon the total load that is being served by the station and the capacity of the transformers installed at the station. If the total station load exceeds the individual transformers' ratings, then it would not be possible.

f) No.

g) The manufacture, process, import, and offer for sale of PCBs and equipment containing liquid with a PCB concentration of greater than 50 ppm (50 mg/kg) was prohibited in Canada in 1977 by way of the *Chlorobiphenyls Regulations (1977)*. However, Hydro One Distribution has identified a limited number of oil-filled equipment that was manufactured between 1977 and 1984 with PCB results greater than 500 ppm PCB oil. As such, Hydro One Distribution has decided to test all equipment that was manufactured prior to 1985 for PCBs.

Hydro One Distribution has 528 transformers and regulators that were manufactured after 1977. These units cannot be considered "PCB free" as they may have been retrofitted with older bushings that contained greater than 50 ppm PCB oil.

Energy Probe INTERROGATORY #66 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 2, pages 16-18

Table 5 shows line maintenance costs for historical, bridge and test years. The amount spent on Line Patrols, Wood Pole Assessment and Asset Data Collection is quite variable.

a) Please explain the variation in costs in this category for the historical years 2006, 2007, 2008.

b) Lines 1-12 on p.18 describe Hydro One's program for inspecting and recording data from its lines. The evidence states that 330,000 poles per year have been captured in the data collection process since 2005 and that 360,000 poles are forecast to be captured in 2010. Why is the cost in 2009 and 2010 so much higher than that in the historical years?

Response

a) The expenditures for Line Patrols, Wood Pole Assessment & Asset Data Collection can vary from year to year depending on a number of factors.

Among historic years, 2007 required the greatest expenditure as over 400,000 poles were patrolled, inspected, and data collected in that year. This is by far the greatest number of poles since the data collection initiative was commenced in 2005.

The 2008 expenditure was lower as fewer than 350,000 poles were inspected and data collected in that year. Variations in the number of poles from one year to the next is expected given that different feeders will be patrolled in different years and that these feeders will have different numbers of poles per kilometre. The reduced expenditures in 2008 were also influenced by the fact that crews in that year were more successful in assessing pole condition during the initial inspection and did not require as much follow up pole testing as in previous years.

b) Expenditures are increasing in 2009 and 2010 as a result of: 1) emphasis on the new submarine cable testing program; and 2) the anticipated need for pole testing related to the 'Red Pine' pole issue. The need driving these expenditures is described at the bottom of pages 17 and 18 in Exhibit C1, Tab 2, Schedule 2.

Energy Probe INTERROGATORY #67 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 2, page 21

This section discusses the sentinel light maintenance program. Annual costs to maintain sentinel lights are $1.4 M. The evidence states that Hydro One is contractually obligated to maintain the historic sentinel light program.

a) Please provide a copy of the standard sentinel light contract that governs the parties in this relationship.

b) Has Hydro One studied the possibility of providing incentives to sentinel light customers to end the contract? If so, what were the results of the study? If not, how does Hydro One know that it has no options other than honouring the contracts?

c) Are sentinel light maintenance costs recovered 100% from the customers with sentinel lights? If not, why not?

Response

a) The sentinel light contracts were entered into by the former Ontario Hydro. Hydro One Distribution does not have copies of specific contracts with individual customers from that time period. Hydro One's obligations with respect to sentinel lights is specified in OReg 116/02 as detailed in Section 3.1 of Exhibit A, Tab 6, Schedule 1.

b) No, Hydro One Distribution has not studied the possibility of providing incentives.

Through relationships developed with sentinel light customers over the years, Hydro One Distribution understands that these customers rely on the service as an affordable means to illuminate their property and to mitigate safety hazards. These customers are prepared to pay the charges associated with the service and are unlikely to cancel the service in response to incentives. As a result, Hydro One Distribution's best available option is to honour the contracts in accordance with its obligations specified in OReg 116/02.

c) Yes, as shown in Schedule 11-2b of Exhibit G2, Tab 93, Schedule 1 the sentinel light charges are based on the full recovery of associated costs.

Energy Probe INTERROGATORY #68 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit *C1,* Tab 2, Schedule 2, page 23

This section describes the pole and padmount transformer PCB testing program.

a) Line 1 states that "Hydro One Distribution has resumed inspecting and testing lines equipment in response to the new PCB regulations."
   i) When did Hydro One suspend its previous testing program?
   ii) What drove the suspension?
   iii) How much inspecting and testing was done under the old program?
   iv) Is the data from that program still available and relevant?

b) Line 5 states that the location of the company's 440,000 pre 1985 pole mounted transformers needs to be verified.
   i) How does Hydro One plan to do this?
   ii) Has this data been included in data collection referred to earlier in the evidence under the heading of line patrols and data collection?
   iii) Does Hydro One have customer accounts and meter numbers cross referenced to supply transformers? If so, is the location not already known by the street addresses of the customer accounts?
   iv) How does Hydro One know that of the 440,000 pre 1985 transformers in the system only about 240,000 are likely to be contaminated by PCBs?

c) What is the procedure for inspecting and testing pole and padmounted transformers for PCB contamination? How many of each can a crew accomplish in a day? What size of crew is required to conduct the inspection and testing for PCBs?

Response

a)

i) Hydro One Distribution suspended its planned PCB Inspection and Testing Program on lines assets in 2004.

ii) As noted in previous applications to the OEB, Hydro One Distribution suspended its PCB programs in 2004 pending the new PCB regulations from Environment Canada. Draft regulations had been issued a few years prior and Hydro One

Distribution was concerned that the proposed new regulations were subject to change and that changes may lead to different requirements and the need for either re-work or less work. Given the "draft" nature of the regulations, Hydro One Distribution suspended the program and elected to wait for certainty and clarity in the form of finalized regulations. The finalized regulations were passed in September 2008.

iii) Under the previous program from 1997 to 2003, over 85,000 transformers were inspected and over 45,000 were tested.

iv) Yes, the data is available and is relevant and has been factored into the current plans.

b)

i) As stated on page 23 of Exhibit C1, Tab 2, Schedule 2, approximately 240,000 of Hydro One Distribution's 440,000 pole mounted transformers are estimated to have been manufactured prior to 1985 and are at risk of being PCB contaminated. Hydro One Distribution's plan is to:

- Use available data (e.g. older inspection and testing data, feeder demographics) to identify newer installations and remove them from the list of transformers that need to be inspected.
- Send line crews to locations of transformers whose manufacture date is unknown to determine the exact age of the unit.
- Take oil samples from units that have been verified through inspections to have been manufactured prior to 1985 and test the oil for PCB content.

ii) Data Collection efforts that were referred to in the evidence are a separate activity that is not related to PCB activities. However, the data collected by those efforts has been relied on to provide the location of each transformer but not the age of each transformer as this information is unattainable from the ground during a routine patrol.

iii) Yes, Hydro One Distribution does have the customer accounts and meter numbers cross referenced to supply transformers. The locations of individual transformers are known but what is missing is information about each transformer's manufactured date. The inspections are designed to capture the manufactured date.

iv) The estimate is based on demographics information and is confirmed by the ratio of units tested to those inspected by previous PCB inspection programs (i.e. 1997 to 2003).

c) The first step in the procedure is for a line crew to visit the transformer location. For pole mount transformers, the line crew must use a bucket truck to access the transformer. The bucket truck is set up at the base of the pole and the lines person would go aloft to examine the nameplate of the transformer. If the date is pre-1985 the unit is drilled, oil sampled and plugged. The sample is sent to a lab for analysis and the results of the analysis are returned at a later date. If a transformer test positively for PCB contamination above 50 ppm, then it is logged and scheduled for future replacement.

The number of units accomplished per day will vary based on numerous factors including the distance (i.e. driving time) between transformer locations and the nature of the location (i.e. busy road or rural environment) of the transformer along with the ease of set up for a bucket truck. Another factor is the number of customers connected to the transformer. All sampling is completed with the transformer removed from service, which will require customer notifications of outages. Given these factors, the number of transformers accomplished by a crew in a given day can vary from a few to over 12. A typical crew would be made up of two line persons.

Energy Probe INTERROGATORY #69 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 2, page 26

Reference is made in this section to increased spending in the test year due to "increases in Health and Safety programs to support the company's strategic safety goals."

Please elaborate on what these programs consist of and how they do a better job of supporting the company's strategic safety goals than previous programs.

Response

Please see response in Exhibit H, Tab 1, Schedule 24.

Energy Probe INTERROGATORY #70 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 2, pages 28-29

This section discusses retail meter maintenance. Costs are noted as $4.9 M in 2010 and $6.2 M in 2011. Elsewhere in the evidence, it is stated that all 1.2 million retail meters will be replaced by smart meters by the end of 2010.

a) Why are the costs in 2010 not lower than 2009 as a result of the declining number of legacy meters in the system?

b) Please confirm that the costs shown in 2011 of $6.2 M are all related to smart meter reverification.

c) How many smart meters were installed in 2006? How many of those will be reverified in 2011?

d) How does the procedure for and frequency of reverification of smart meters differ from that for legacy electromechanical meters?

e) Does Hydro One have its own meter shop authorized by Measurement Canada to perform reverification tests?

Response

a) Please refer to Exhibit H, Tab 1, Schedule 25.

b) The 2011 "Customer Retail Meters" cost of $6.2M are not all related to Smart Meter re-verification. The majority of the costs are for field metering services, meter and relay services at the central shop, and inventory sustainment for all meter types including non-smart meters. The expenditure does include a small number (i.e. 600) of smart meter re-verifications.

c) There were 27,600 meters installed in 2006. Please refer to the response for part b) above.

d) There is no change to the Measurement Canada metrology sample/re-verification requirements. The expectation is that most of the smart meter types will have a 10-year seal period although some will have a 6-year seal period. These requirements have yet to be finalized.

e) Yes, Hydro One does have a fully accredited shop to test, reverify and reseal meters.

Energy Probe INTERROGATORY #71 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 4, page 8

This section summarizes the reasons for increased spending on distribution system operations "as a result increased focus on Distribution elements in alignment with distributed generation, smart meter, and smart grid influences".

a) How much additional staff will be required for this increased effort? Has this staff been hired yet?

b) What is the training period required to get this new staff to a journeyman level of performance?

Response

a) In 2009, one additional staff was hired as a result of distributed generation. The current forecast is to hire twelve additional staff in 2010 and eight in 2011 for additional work related to the Green Energy Plan.

b) Depending on the role and the experience of the individual hires, the training period required varies from six months to three years.

Energy Probe INTERROGATORY #72 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 5, page 8

This page describes the transition from manual to automated meter reading over the bridge and test years.

a) How many meter readers does Hydro One currently have on regular staff?

b) How many meter readers does Hydro One expect will be needed after smart meters are fully deployed in 2010?

c) What is Hydro One's plan for dealing with surplus meter readers?

Response

a) Currently there are 75 meter readers on regular staff. The number of meter readers on staff is declining with attrition and redeployment. Regular positions are not being backfilled, but rather temporary resources are being used (e.g. from hiring hall) to complete the program for 2009.

b) As stated in Exhibit C1, Tab 2, Schedule 5, page 8 Section 2.1.2, the migration of customers to automated meter reading will continue throughout 2010 and to the end of 2011. Post activation of smart meters there will continue to be manual meter readings required at remote locations where smart meter communications is not available, to check read at customer requests, or for meter investigations.

Hydro One's 2011 plan includes a requirement for 40 meter readers on regular staff, and the use of temporary resources.

c) The majority of meter readers will be moved to new duties, including meter changes, final reads, high bill complaints, cable locates, data collection, cut in/cut out activities.

Energy Probe INTERROGATORY #73 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 2, Schedule 8
Exhibit C2, Tab 2, Schedule 1

Page 1 and 2 of the C2 T2 Sl present a table showing comparison of OM&A expense by major category. Shared services and other costs are shown as increasing from $92.4 M in 2009 to $123.2 M in 2010 and $119M in 2011.

a) A significant part of the increase is attributable to Common Asset Management Costs. One of the categories within this group of costs is Real Estate and Facilities which has increased costs that are attributed to "new space - accommodation requirements driven by the increasing work programs across the Company" according to lines 14-16 on page 16 of C1 T2 S8. Please provide details of what new "space - accommodation" is needed and why.

b) Information management services shows increased cost from $69.3 M in 2009 to $79.1 M in 2010 and $81.9 M. Although there is considerable material presented in the evidence to explain OM&A costs in IT, it is confusing and difficult to interpret why costs are increasing. Please provide a succinct explanation for the overall increase in this category.

c) Cornerstone costs in the table are shown as net of expected savings which results in credit entries in 2009, 2010 and 2011. Because OM&A costs are intuitively positive numbers, the entries in Cornerstone for the bridge and test years do not appear to make sense i.e, it looks like the company will actually generate revenue from OM&A activities required to support this system. Please explain why the costs are presented in this way.

Response

a) Please refer to the interrogatory response in Exhibit H, Tab 9, Schedule 24.

b) The increase from 2009 to 2010 is $9.8M or 14%. This increase is caused by:

- Incremental application support and maintenance of SAP resulting from the completion of Cornerstone Project.

- Re-organizational transfer of the Information Asset department from Asset Management to IT. Please refer to interrogatory response in Exhibit H, Tab 1, Schedule 51
- Small projects deferred until the completion of the Cornerstone phase 1 and phase 2 projects are now proceeding with the highest priority projects in this category.
- Increase in Telecom Services cost due to the GEGEA work program assessment and the projected head count increases.

The forecasted increase in 2010 to 2011 is $2.8M. We have applied a 3.5% increase to 2010 to be in-line with estimated COLA increases in labour and sustainment costs for 2011.

c) The Cornerstone OM&A costs, identified in Table 1 Exhibit C1, Tab 2 Schedule 10, page 1, show Cornerstone OM&A savings to be greater than the associated OM&A Development cost for 2010 and 2011. The total costs are presented in this manner to show net effect/offset on the total Shared Services and Other Cost shown in Exhibit C2, Tab 2, Schedule 1, page 2.

Energy Probe INTERROGATORY #74 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit C1, Tab 3, Schedule 1

This schedule is concerned with corporate staffing. Although an explanation of staffing needs is presented no staffing levels are provided.

If this is elsewhere in the evidence please advise where it can be found. If it is not in the evidence, please provide an analysis of staffing levels broken down into appropriate employee groups such as PWU, Society, Management, Executive etc. for historical, bridge and test years along with an explanation for staffing increases or decreases.

Response

See Exhibit H, Tab 7, Schedule 67.

Energy Probe INTERROGATORY #75 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit Dl, Tab 3, Schedule 3, page 14
Exhibit D2, Tab 2, Schedule 3, Project D27

On page 14 of the first reference, the statement is made that "The benefit to load customers is estimated to be about 15% of the cost for connection of generators in the large (>10MW) and mid-size (500kW to 10MW)".

a) How did Hydro One arrive at this estimated benefit?

b) The benefit to ratepayers ascribed to Project D27 in the second reference appears to be 85%. Why is this benefit different than the estimated 15%?

Response

a) & b) The evidence associated with the two references stated in this interrogatory was revised as part of the Update filed by Hydro One Distribution on September 25, 2009.

The methodology used by Hydro One to estimate the benefit to load customers for different types of investments is described on pages 17-19, for Expansion investments, and on pages 21-23, for Renewable Enabling Improvements (REI) investments, of the updated Green Energy Plan filed at Exhibit A, Tab14, Schedule 2.

Energy Probe INTERROGATORY #76 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit Dl, Tab 3, Schedule 7

Page 4 of this schedule states that savings from Cornerstone Phase 1 will be about $200 SM. An explanation for the bulk of the savings appears in lines 5-17 on page 5. These total only about $120 M.

a) Please explain where the other $80 M in savings is expected to come from.

b) For each of the three bullet points in the explanation appearing at lines 717 on page 5 please explain in detail how the expected savings were calculated.

c) Does Hydro One have a methodology to confirm these savings as they occur? If so please explain it. If not, how will Hydro One be able to conclude that it achieved the savings?

Response

a) The three Cornerstone Phase 1 deliverables described on page 5 provide the majority of the expected savings (i.e. 60%). A number of other initiatives make up the balance of the expected savings. These include:

- Leverage technology and information systems to achieve efficiency
- Improved inventory performance
- Increased back office productivity (Planner / Designer / Clerical)
- Improved Evaluated Receipts Settlement processes – through better automation
- Better work planning and bundling for maintenance and project work
- Improved system reliability through higher quality asset data
- Improved warehouse shipping processes and payment reconciliation with carrier
- Greater control governance around one-time setup vs. regular Accounts Payable vendor setup
- Improved large Tx customer satisfaction through more detailed reporting and improved connection process

b) Expected Cornerstone savings were determined by a value realization team comprised of representatives from various business units. The team assessed the impact of Cornerstone on each Hydro One business processes. The results were reviewed and approved by Hydro One senior management.

The expected savings for each of the three bullets is determined as follows:

- Optimize O&M and Capital spend through enhanced asset analysis and maintenance by managing operational risks over the asset life cycle (Expected Savings $50.3M).

  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.

- Enhanced 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 (Expected Savings $35.5M).

  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.

- Improve internal & supplier contract compliance 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 (Expected Savings $35M).

  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.

c) Yes.

Many of the Cornerstone savings are related to process improvements. Hydro One tracks these process improvements to record the achievement of expected savings.

For further information on Cornerstone and associated savings please see EB-2007-0681, Exhibit H, Tab 1, Schedule 38 and RP-2005-0020/EB-2005-0378, Exhibit H, Tab 4, Schedule 64.

Energy Probe INTERROGATORY #77 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit Dl, Tab 3, Schedule 7

Line 17 on Page 8 through line 16 on page 9 of this schedule presents an explanation for the estimated $50 M in savings estimated for Phase 2 of the Cornerstone project. For each of the bullet points in the two categories of savings shown in these lines please explain in detail how the expected savings were calculated.

Response

Please see response at Exhibit H, Tab 3, Schedule 76 b).

Energy Probe INTERROGATORY #78 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit D1, Tab 3, Schedule 7

Lines 1-4 on page 11 of this schedule show estimated savings for Phase 3 of the Cornerstone project at $130 M. These savings are attributable to "improved processes, elimination of duplicative data systems and improved transparency across the organization." Please explain in detail how these savings were calculated.

Response

Please see response in Exhibit H, Tab 3, Schedule 76 b).

Energy Probe INTERROGATORY #79 List 2

Interrogatory

Issue 3.1 - Are the overall levels of the *2010/2011* Operation, Maintenance and Administration budgets appropriate?

Ref: Exhibit D1, Tab 3, Schedule 7

Total estimated savings from the Cornerstone project are $380 M arrived at by adding the savings from the previous three IRs together.

Does Hydro One have a methodology for measuring these savings as they occur over the 7 year time period? If yes, please explain the methodology in detail. If no, how will Hydro One determine if it achieved the expected savings?

Response

Please see response in Exhibit H, Tab 3, Schedule 76 b).

Pollution Probe INTERROGATORY #1 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the actuals for each of Hydro One's 2006 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

For the year 2006, Hydro One rate funded (MARR) CDM expenditures were $16.3 million as shown in Table 1 below (for more details, refer to 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).

Table 1: MARR Funding – Summary of Spending and Savings for the year 2006

MARR Funding – Year 2006 Results					
PROGRAM	**SPENDING ($K)**	**PARTICIPANTS / UNITS**	**ANNUAL SAVINGS (MWh)**	**SAVINGS (MW)**	**Annual Net TRC Benefits ($K)***
Residental					
Smart Meters	$7, 281	19,491			
Real Time Monitoring Pilot	$(1)				
Real Time Monitoring Program	$3,242	19,948	14,809.1	3.4	$1,986
Mass Market	$1,105	756,778	74,462.8	4.4	$38,951
LED	$125	21,809	327.4		$439
Low Income / Social Housing	$451	1,786	294.1	0.0	$188
Load Control Pilot	$(73)				
Load Control Program	$2,117	1,687	806.4	2.2	$1,983
Energy Audit Analysis					
Total	$14,247	821,499	90,699.8	9.9	$43,548
Commercial / Industrial, Farm, MUSH					
Interim Time of Use	$394	3			
C/I MUSH Conservation	$(148)	1,1783	185.4	0.0	$86
C/I & Farm Load Control	$2				$(44)
Farm Energy Efficiency	$1	94	64.0	0.0	$291
Total	$249	1,880	249.4	0.0	$332
Common					
Distribution Loss Reduction	$877				$(877)
Program Management and Research	$772				$(697)
Communication and Education	$145				$(158)
Carrying Charge					
Total	$1,794	0	0		$(1,732)
Grand Total	**$16,290**	**823,379**	**$90.949**	**9.9**	**$42,148**

* Hydro One ran several multi-year programs. Therefore, program costs may have started in 2006 while TRC benefits materialized later. To have a complete picture of a program, it is necessary to look at the Life To Date (LTD) results filed with the most recent CDM Annual Report.

Pollution Probe INTERROGATORY #2 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the actuals for each of Hydro One's 2007 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

For the year 2007, Hydro One's rate funded (MARR) CDM expenditures were $17.8 million as shown in Table 1 below (for more details, refer to the 2007 CDM Annual Report filed with the OEB on April 2, 2008 available online at http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Conservation+and+Demand+Management+(CDM)/CDM+Reports+Plans+and+Applications)

Table 1: MARR Funding - Summary of Spending and Savings for the year 2007

MARR Funding – Year 2007 Results					
PROGRAM	**SPENDING ($K)**	**PARTICIPANTS / UNITS**	**ANNUAL SAVINGS (MWh)**	**SAVINGS (MW)**	**Annual Net TRC Benefits ($K)***
Residental					
Smart Meters					
Real Time Monitoring Pilot	$1,840	10,652	8,137.0	1.4	$970
Real Time Monitoring Program	$1,083	249,077	17,190.8	1.2	$6,056
Mass Market	$128				$(128)
LED	$2,666	23,100	8,079.0	0.9	$3,419
Low Income / Social Housing					
Load Control Pilot	$2,419	8,313	3,306.7	11.0	$8,810
Load Control Program	$213				$(213)
Energy Audit Analysis (Online Audit)					
Total	$8,349	291,142	36,713.4	14.5	$18,914
Commercial / Industrial, Farm, MUSH					
Interim Time of Use	$365	3			
C/I MUSH Conservation	$735	912	14,317.8	2.0	$9,820
C/I & Farm Load Control	$2,337	29,652	108,854.2	33.8	$7,183
Farm Energy Efficiency	$347	35	1,906.7	0.3	$762
Total	$3,784	30,602	125,078.7	36.1	$17,765
Common					
Distribution Loss Reduction	$4,522	219	7,207.7	2.4	$4,843
Program Management and Research	$849	411	396.2	0.0	$(704)
Communication and Education	$294	7,800	3,363.4	0.1	$2,365
Carrying Charge					
Total	$5,665	8,430	10,967.2	2.5	$6,504
Grand Total	**$17,798**	**330,174**	**172,759.3**	**53.1**	**$43,183**

* Hydro One ran several multi-year programs. Therefore, program costs may have started in 2007 while TRC benefits materialized later. To have a complete picture of a program, it is necessary to look at the Life To Date (LTD) results filed with the most recent CDM Annual Report.

In 2007, Hydro One also participated in programs funded through the Global Adjustment Mechanism (OPA Core Programs). Expenditures were $8.3 million.

Hydro One is required to report only spending and participants to the OPA. Reporting of MW, MWh, and TRC is the responsibility of the OPA. Hydro One does not have access to OPA related costs and cannot therefore calculate TRC Net Benefits. The 'Net" Benefits in the table below have been estimated as Hydro One's portion of the TRC Net Benefits by using OPA's EM&V results where available.

Table 2: 2007 Global Adjustment Mechanism Funding, Summary of Spending and Savings

2007 Global Adjustment Mechanism Funding – OPA Core Program					
Year 2007 – OPA Programs	**Actual spending (Program Cost + Customer incentives) ($K)**	**PARTICIPANTS / UNITS**	**ANNUAL SAVINGS (MWh)***	**SAVINGS (MW)***	**Hydro One's portion of TRC Net Benefits ($K)***
SummerSavings*	$5,468	247,154	23,342	12	$3,017
Electricity Retrofit Incentive Program	$120	1	0	0	$(120)
Great Refrigerator Roundup	$70	13,448	5,422	1	$1,172
PeakSaver	$2,690	4,634	590	5	$6,462
Total	**$8,348**	**265,237**	**29,354**	**18**	**$10,531**

* Part of SummerSavings on-bill credits were paid at the beginning of 2008 (for MWh savings related to the 2007 summer); the entire acutal budget is shown in this table to reflect costs and savings appropriately

Pollution Probe INTERROGATORY #3 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the actuals for each of Hydro One's 2008 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

For the year 2008, Hydro One' rate funded (MARR) CDM expenditures were $1.4 million. (for more details, refer to the 2008 CDM Annual Report filed with the OEB on April 3, 2009 available online at http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Conservation+and+Demand+Management+(CDM)/CDM+Reports+Plans+and+Applications)

Table 1:
MARR Funding - Summary of Spending and Savings for the year 2008

MARR Funding – Year 2008 Results					
PROGRAM	**SPENDING ($K)**	**PARTICIPANTS / UNITS**	**ANNUAL SAVINGS (MWh)**	**SAVINGS (MW)**	**Annual Net TRC Benefits ($K)**
Residental					
Smart Meters					
Real Time Monitoring Pilot					
Real Time Monitoring Program					
Mass Market	$2	7,254	4,559.7	0.8	$(2)
LED	$8				$(8)
Low Income / Social Housing	$4				$(4)
Load Control Pilot					
Load Control Program					
Energy Audit Analysis					
Total	$14	7,254	4,559.7	0.8	$(14)
Commercial / Industrial, Farm, MUSH					
Interim Time of Use	$148				
C/I MUSH Conservation	$67	4,098	901.6	0.2	$351
C/I & Farm Load Control					
Farm Energy Efficiency					
Total	$215	4,098	901.6	0.2	$351
Common					
Distribution Loss Reduction	$1,153	67	7,236.5	2.6	$8,738
Program Management and Research					
Communication and Education	$5				$(5)
Carrying Charge					
Total	$1,158	67	7,236.5	2.6	$8,733
Grand Total	**$1,387**	**11,419**	**12,697.8**	**3.7**	**$9,070**

In 2008 there were also some costs associated with on-going administration of the CDM work, which were included as part of the 2008 rates application. The Table below shows the ongoing rate funded projects and associated savings (for more details, refer to the 2008 CDM Annual Report filed with the OEB on April 3, 2009 available online at

http://www.oeb.gov.on.ca/OEB/Industry+Relations/OEB+Key+Initiatives/Conservation+and+Demand+Management+(CDM)/CDM+Reports+Plans+and+Applications).

Table 2:
2008 Rate funded Program costs for the on-going administration of the CDM work

2008 Incremental Funding						
PROGRAM ACTIVITIES		**INCREMENTAL EXPENDITURES ($K)**	**PARTICIPANTS / UNITS**	**ANNUAL SAVINGS (MWh)**	**SAVINGS (MW)**	**TRC Net Benefits ($K)**
Maintenance of Current Program						
Residential						
Cold Shoulder Appliance Pickup		$16	100	120	0	$50
Load Control Program		$78				$(78)
PowerSaver Plus Online Energy Audit		$60				$(60)
Low Income / Social Housing						
Low Income / Social Housing		$46	25	109	0	$106
Commercial / Industrial, Farms, MUSH						
PowerSaver Business Incentive Program		$1	1	7		$6
C/I Load Control (Double Return)		$104	600	168		$81
Interim Time of Use		$43				
Farm Load Control (Leamington DG)		$51				$(51)
Maintenance of Current Programs	**Subtotal**	**$399**	**726**	**404**	**0**	**$54**
PowerHouse Pilot Program	**Subtotal**	**$200**	**22**	**(108)**		**$592**
Program Management and Research						
- Survey		$33	6,600			$(33)
- Research		$214				$(214)
- Education		$2	1			$(2)
Program Management and Research	**Subtotal**	**$249**	**6,601**			**$249)**
	Total	**$848**	**7,349**	**296**	**0**	**$397**

In 2008, Hydro One also participated in programs funded through the Global Adjustment Mechanism (OPA Core and Custom Programs). Expenditures were $5.9 million. Hydro One also received $0.7 million in funding from the Ontario Ministry of Energy for a pilot (PowerHouse) program for renewable energy.

Hydro One is required to report only spending and participants to the OPA. Reporting of MW, MWh, and TRC is the responsibility of the OPA. Hydro One does not have access to OPA related costs and cannot therefore calculate TRC Net Benefits. The 'Net" Benefits in the table below have been estimated as Hydro One's portion of the TRC Net Benefits by using OPA's EM&V results where available.

Table 3:
Global Adjustment Mechanism Funded and Ministry of Energy Funded programs
Summary of Spending and Savings

2008 Programs					
YEAR 2008 PROGRAMS	**ACTUAL BUDGET (PROGRAM COSTS + INCENT) ($K)**	**PARTICIPANTS (Customers or Units)**	**ANNUAL SAVINGS (MWh)**	**SAVINGS (MW)**	**Hydro One's Portion of TRC Net Benefits ($K)***
Global Adjustment Mechanism Funding – OPA Core Program					
SummerSweepstakes	$225	19,245	1,764		58
Electricity Retrofit Incentive Program	$890	149	12,300	2.7	$4,250
Great Refrigerator Roundup	$210	23,700	11,400	1.3	$2,068
PeakSaver	$3,324	5,500	1,400	5.0	$7,133
Power Savings Blitz*	$90		n/a	n/a	n/a
Global Adjustment Mechanism Funding – OPA Custom Program					
Double Return	$1,200	120			
Distribution		117	35,415	19.6	$4,925
Transmission		3	46,224	22.5	$5,925
Ministry of Energy Funded					
PowerHouse Program	$700	76	(250)	0	$1,140
Total	**$6,639**	**48,910**	**108,253**	**51.1**	**$25,769**

*Acutal retrofits took place in 2009, during the three months extension (January to March 2009) of this program; therefore, no savings were reported in 2008

Pollution Probe INTERROGATORY #4 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the best available information for each of Hydro One's 2009 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

For 2009, HONI expects to spend $1 million from distribution rates for administration of CDM work, $1.4 million from the Ontario Ministry of Energy and Infrastructure for a pilot (PowerHouse) program for renewable energy, and $15.5 million from the Global Adjustment Mechanism (OPA Core and Custom Programs). Expected spending, participants, savings (MW and MWh) and TRC Net Benefits (where information is available) for all CDM programmes are shown in the table below.

Hydro One is required to report only spending and participants to the OPA. Reporting of MW, MWh, and TRC is the responsibility of the OPA. Hydro One does not have access to OPA related costs and cannot therefore calculate TRC Net Benefits. The 'Net" Benefits in the table below have been estimated as Hydro One's portion of the TRC Net Benefits by using OPA's EM&V results where available.

Table 1: Global Adjustment Mechanism Funded, Ministry of Energy Funded and Rate Funded programs Summary of Spending and Savings

2009 Forcast					
YEAR 2009	**FORECASTED EXPENDITURE (PROGRAM COSTS + INCENT) ($K)**	**ESTIMATED PARTICIPANTS (Customers or Units)**	**EST. ANNUAL SAVINGS (MWh)***	**EST. SAVINGS (MW)***	**Hydro One's Portion of TRC Net Benefits ($K)***
Rate Funded Administration of CDM Work					
Maintenance of MARR Funded Programs and Minimum Capability	$1,000	Not Available	Not Available	Not Available	Not Available
Ministry of Energy Funding					
PowerHouse Program	$1,400	153	(501)	0	$2,815
Global Adjustment Mechanism Funding – OPA Core Program					
Electricity Retrofit Incentive Program*	$2,650	160	12,900	3.6	$8,476
Great Refrigerator Roundup	$500	23,000	11,400	1.3	$1,708
PeakSaver	$4,125	7,500	2,000	7.0	$10,463
Power Savings Blitz**	$7,100	5,350	20,000	5.8	$4,149
Global Adjustment Mechanism Funding – OPA Custom Program					
Double Return	$1,200	119			
Distribution		111	44,280	19.6	$2,159
Transmission		8	70,831	22.5	$3,614
Total	**$17,975**	**36,282**	**160,911**	**59.8**	**$33,384**

* Assumptions for various technologies and programs not yet finalized by OPA; EM&V will commence in 2010

Pollution Probe INTERROGATORY #5 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the forecasts for each of Hydro One's 2010 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

As at October 19, 2009 no budgets or targets have yet been established for 2010 CDM programs - which are expected to be funded from Global Adjustment Mechanism. All existing contracts with the OPA expire in 2010 and the GEGEA has not yet been operationalized. The table below assumes that the 2010 programs are the same as 2009 and that there is no interruption in funding. Expenditures and results have been adjusted from 2009 to reflect a full year of operation at current activity levels.

There are also some costs associated with on-going administration of the CDM work ($1M forecasted Budget), which are included as part of rates.

Hydro One is required to report only spending and participants to the OPA. Reporting of MW, MWh, and TRC is the responsibility of the OPA. Hydro One does not have access to OPA related costs and cannot therefore calculate TRC Net Benefits. The 'Net" Benefits in the table below have been estimated as Hydro One's portion of the TRC Net Benefits by using OPA's EM&V results where available.

2010 Forcast					
YEAR 2010	**FORECASTED EXPENDITURE (PROGRAM COSTS + INCENT) ($K)**	**ESTIMATED PARTICIPANTS (Customers or Units)**	**EST. ANNUAL SAVINGS (MWh)***	**EST. SAVINGS (MW)***	**Hydro One's Portion of TRC Net Benefits ($K)***
Rate Funded Administration of CDM Work					
Maintenance of MARR Funded Programs and Minimum Capability	$1,000	Not Available	Not Available	Not Available	Not Available
Global Adjustment Mechanism Funding – OPA Core Program					
Electricity Retrofit Incentive Program*	$2,650	160	12,900	4.0	$8,028
Great Refrigerator Roundup	$600	23,000	11,400	1.3	$1,457
PeakSaver	$6,500	10,000	2,400	9.0	$13,504
Power Savings Blitz**	$12,750	12,000	47,000	14.0	$20,107
Total	**$23,500**	**45,160**	**73,700**	**28.3**	**$43,096**

* Assumptions based on latest information available from OPA EM&V studies and program planning inputs

Additional programs are expected to be implemented once targets and funding have been established for all LDCs by the Board. The funding for such programs is not expected to impact Hydro One's distribution rates.

Pollution Probe INTERROGATORY #6 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the forecasts for each of Hydro One's 2011 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

As at October 19, 2009 no budgets or targets have yet been established for 2011 CDM programs - which are expected to be funded through the Global Adjustment Mechanism. All existing contracts with the OPA expire in 2010 and the GEGEA has not yet been operationalized. The table below assumes that the 2011 programs are the same as 2010 and that expenditures and results are also the same.

There are $1M in costs associated with on-going administration of the CDM work which are included as part of rates.

Hydro One is required to report only spending and participants to the OPA. Reporting of MW, MWh, and TRC is the responsibility of the OPA. Hydro One does not have access to OPA related costs and cannot therefore calculate TRC Net Benefits. The 'Net" Benefits in the table below have been estimated as Hydro One's portion of the TRC Net Benefits by using OPA's EM&V results where available.

2011 Forcast					
YEAR 2011	**FORECASTED BUDGET (PROGRAM COSTS + INCENT) ($K)**	**ESTIMATED PARTICIPANTS (Customers or Units)**	**EST. ANNUAL SAVINGS (MWh)***	**EST. SAVINGS (MW)***	**Hydro One's Portion of TRC Net Benefits ($K)***
Rate Funded Administration of CDM Work					
Maintenance of MARR Funded Programs and Minimum Capability	$1,000	Not Available	Not Available	Not Available	Not Available
Global Adjustment Mechanism Funding – OPA Core Program					
Electricity Retrofit Incentive Program	$2,650	160	12,900	4.0	$8,028
Great Refrigerator Roundup	$600	23,000	11,400	1.3	$1,457
PeakSaver	$6,500	10,000	2,400	9.0	$13,504
Power Savings Blitz	$12,750	12,000	47,000	14.0	$20,107
Total	**$23,500**	**45,160**	**73,700**	**28.3**	**$43,096**

* Assumptions based on latest information available from OPA EM&V studies and program planning inputs

Additional programs are expected to be implemented once targets and funding have been established for all LDCs by the Board. The funding for such programs is not expected to impact Hydro One's distribution rates.

Pollution Probe INTERROGATORY #7 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the forecasts for each of Hydro One's 2012 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

As at October 19, 2009 no budgets or targets have yet been established for 2012 CDM programs - which are expected to be funded from Global Adjustment Mechanism. All existing contracts with the OPA expire in 2010 and the GEGEA has not yet been operationalized.

Hydro One Distribution understands that there are a number of processes under way to operationalize the GEGEA, including:

- preparation of GEGEA regulations/directives;
- development of CDM targets for each distributor;
- development of CDM portfolio/program requirements/tests; etc.

Once these processes have been completed, Hydro One Distribution will be in a position to assemble a portfolio of CDM programs for the Board's review and approval. Hydro One's understanding is that more CDM is desired rather than less, so 2012 expenditures are expected to be at least equal to current levels.

Pollution Probe INTERROGATORY #8 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the forecasts for each of Hydro One's 2013 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

As at October 19, 2009 no budgets or targets have yet been established for 2013 CDM programs - which are expected to be funded through the Global Adjustment Mechanism. All existing contracts with the OPA expire in 2010 and the GEGEA has not yet been operationalized.

Hydro One Distribution understands that there are a number of processes under way to operationalize the GEGEA, including:

- preparation of GEGEA regulations/directives;
- development of CDM targets for each distributor;
- development of CDM portfolio/program requirements/tests; etc.

Once these processes have been completed, Hydro One Distribution will be in a position to assemble a portfolio of CDM programs for the Board's review and approval. Hydro One's understanding is that more CDM is desired rather than less, so 2013 expenditures are expected to be at least equal to current levels.

Pollution Probe INTERROGATORY #9 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please provide the forecasts for each of Hydro One's 2014 CDM programmes': a) budget; b) number of participants; c) annual MWh savings; d) MW savings; and e) TRC net benefits.

Response

As at October 19, 2009 no budgets or targets have yet been established for 2014 CDM programs - which are expected to be funded through the Global Adjustment Mechanism. All existing contracts with the OPA expire in 2010 and the GEGEA has not yet been operationalized.

Hydro One Distribution understands that there are a number of processes under way to operationalize the GEGEA, including:

- preparation of GEGEA regulations/directives;
- development of CDM targets for each distributor;
- development of CDM portfolio/program requirements/tests; etc.

Once these processes have been completed, Hydro One Distribution will be in a position to assemble a portfolio of CDM programs for the Board's review and approval. Hydro One's understanding is that more CDM is desired rather than less, so 2014 expenditures are expected to be at least equal to current levels.

Pollution Probe INTERROGATORY #10 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please state Hydro One's actual and forecasted number of:

a) residential *peaksaver* participants as of December 31, 2008 and December 31, 2009 respectively; and
b) small business *peaksaver* participants as of December 31, 2008 and December 31, 2009 respectively.

Response

The table below provides the actual and forecast for Hydro One *peaksaver* participants.

***peaksaver* participants**	**Actual as on December 31, 2008**	**Forecast for December 31, 2009**
Residential participants	20,365*	27,846*
Small Business participants	439	519

* Includes 10,000 SmartStat participants. SmartStat devices have been dispatched whenever a PeakSaver load control event has been called.

Pollution Probe INTERROGATORY #11 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please state the number of *peaksaver* participants that Hydro One controlled on August 17, 2009 and the resulting savings (in MWs).

Response

The number of *peaksaver* participants that Hydro One controlled on August 17, was 22,300 and the estimated curtailment as per Ontario Power Authority guideline is 19.7 MW.

Hydro One is also an aggregator for 6 LDCs and therefore controlled an additional 4,620 *peaksaver* participants with an estimated curtailment of approximately 4.0 MW.

Pollution Probe INTERROGATORY #12 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please state the kW savings of an average Hydro One residential *peaksaver* participant and an average Hydro One small business *peaksaver* participant.

Response

Below is the average Hydro One *peaksaver* participant savings as per Ontario Power Authority's guideline.

Assumed kW Controlled:	**kW**
Residential Water Heaters	0.3
Commercial Water Heaters	1.85
Residential AC Thermostats	0.865
Commercial AC Thermostats	3.7

Pollution Probe INTERROGATORY #13 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please state Hydro One's potential number of:

a) residential peaksaver participants; and
b) non-residential peaksaver participants.

Please clarify as to whether these numbers include existing peaksaver participants.

Response

a) At a penetration rate of 25% of customers with central air conditioning, Hydro One's potential number of residential peaksaver participants is estimated at approximately 100,000 customers over time, including the existing participants.

b) Peaksaver does not currently allow the participation of business customers with a demand of more than 50 kW and has not been designed for business customers. The program would need to be redesigned to significantly penetrate the business sector. Under current rules, Hydro One's potential non-residential peaksaver participants is estimated at 2,000 customers over time, including the existing participants.

Pollution Probe INTERROGATORY #14 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please state Hydro One's forecasted number of *peaksaver* participants in 2010, 2011, 2012, 2013, and 2014.

Response

Funding has not yet been negotiated for 2010 or beyond and the current peaksaver and Master Agreements with the OPA expire in 2010. Assuming appropriate funding and structure, HONI anticipates being able to add an incremental 10,000 participants in 2010, bringing the total number of participants to approximately 38,400.

Air conditioning load control for 2011 and beyond needs to transition from pager technology to smart grid technology and Hydro One needs to be able to re-design peaksaver to increase the results achieved to date. With proper re-design there is sufficient potential to add an average of 10,000 customers per year for 2011 through 2014.

Pollution Probe INTERROGATORY #15 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please state Hydro One's maximum payment per kW and per kWh for electricity savings pursuant to its Electricity Incentive Retrofit Program.

Response

As per the prescriptive measures list for the Electricity Retrofit Incentive Program (ERIP), customers are provided an incentive of $60 per ton of cooling for the installation of an ENERGY STAR qualified Unitary Air Conditioning Unit. The OPA has denoted the kW savings to be 0.052 kW per ton for this measure.

Under ERIP, customer incentives are not paid based on kWh savings.

Pollution Probe INTERROGATORY #16 List 1

Interrogatory

Issue #9: The Green Energy Plan

Please state Hydro One's forecasted total capital budget for CDM in 2010, 2011, 2012, 2013 and 2014. Please also provide a break-out of these budgets by their major components.

Response

There is no capital budget associated with CDM.

EnviroCentre INTERROGATORY #1 List 1

Interrogatory

The Green Energy and Green Economy Act (GEGEA) requires the Ontario Energy Board to assess licensed distributors to fund Conservation and Demand Management (CDM) and renewable energy programs but, relying on "past Distribution hearings", the Applicant maintains that CDM costs are "not part of the costs before the Board in this proceeding"[1]. Does the Applicant believe the GEGEA is a break with the past or does the Applicant believe it can continue business as usual when it comes to CDM and renewable programs?

Response

Hydro One's understanding of the GEGEA is that it provides for the OEB being issued a directive requiring the Board to assign CDM targets to licensed distributors and that costs for CDM programs approved by the Board would be paid for by Global Adjustment via the IESO. Hydro One's understanding is that such a directive has not yet been received by the Board.

[1] Letter of September 18, 2009 from Susan Frank, Hydro One Networks Inc., to the Board.

EnviroCentre INTERROGATORY #2 List 1

Interrogatory

Does the Applicant believe that CDM programs funded by the Ontario Power Authority (OPA) or the Global Adjustment Mechanism (GAM) are not subject to Board scrutiny or does it support the acknowledgement in its Green Energy Plan (GEP) that "the Board is still mandated to approve funding for CDM programs"? (Page 32, GEP)

Response

Please see response to Exhibit H, Tab 5, Schedule 1.

EnviroCentre INTERROGATORY #3 List 1

Interrogatory

Can the Applicant explain why its need to start the new work proposed in its GEP to meet the demands of renewable generation[2] is greater than its need to start the new work proposed in its GEP to meet the demands of CDM?

[2] op. cit.

Response

The statement from the Letter of September 18, 2009 from Susan Frank to the OEB - "Hydro One needs to start the work proposed in the GEP to meet the demands of renewable generation and cannot wait until a Generic Proceeding process would be completed" was not intended to imply that Hydro One's need to start the new work proposed in its GEP to meet the demands of renewable generation is greater than its need to meet the demands of CDM.

The letter simply recognizes that Hydro One Distribution believes that the details required for approval of the work required to enable renewable energy generation is appropriately detailed in its Green Energy Plan and the company believes this work can and should be approved as part of the Capital budget requested in its Application. As recognized on page 32 of its Green Energy Plan, Hydro One Distribution understands that there are a number of processes under way to operationalize the *Green Energy and Green Economy Act* objectives with respect to CDM. Only when these processes have been completed will Hydro One Distribution be in a position to assemble a portfolio of CDM programs for the Board's review and approval.

EnviroCentre INTERROGATORY #4 List 1

Interrogatory

The Applicant appears to believe that it would be "prudent and responsible" to postpone new investments in CDM until it receives specific targets. Is the Applicant prepared to start investing now in building capacity to meet the targets that the GEGEA allows for, that the Government of Ontario has called for, and that the Applicant plans for in 2012? (Page 1, GEP)

Response

Hydro One believes it is prudent and responsible that those who benefit from CDM programs should pay the cost of CDM programs. Since the primary benefit of CDM programs is the avoided cost of generation, all customers benefit and all customers should pay. Global Adjustment is the mechanism whereby all customers can pay for CDM programs. The LDC fund administered by the OPA is paid for by Global Adjustment and the GEGEA anticipates a process whereby distributors will be able to receive approval from the Board for CDM programs to be funded by Global Adjustment via the IESO. Hydro One expects to have access to the Global Adjustment through both of these mechanisms.

EnviroCentre INTERROGATORY #5 List 1

Interrogatory

Can the Applicant provide empirical evidence showing the results of its experience with the "full suite of core OPA CDM programs and some customer programs", notably the actual – not projected – kWh and demand savings achieved since 2004 by the Great Refrigerator Roundup, ERIP, PeakSaver, and the Power Saving Blitz? (Page 31, GEP)

Response

The referenced program commenced in 2007, except for Power Saving Blitz which commenced in 2008. Please see responses to Exhibit H, Tab 4, Schedule 2 through Exhibit H, Tab 4, Schedule 4, for data regarding those programs.

EnviroCentre INTERROGATORY #6 List 1

Interrogatory

Can the Applicant explain how limiting its role to simply providing its "customers with information and tools that allow them greater understanding and control over their electricity consumption" will help it achieve the goals of the GEGEA? (Page 11, GEP)

Response

Hydro One cannot take action for customers. Hydro One can only offer assistance to customers to aid them in controlling the amount and timing of their electricity consumption. This assistance can take the form of information or tools – for clarity, Hydro One views CDM programs as tools that customers can choose to use to assist them in controlling the amount and timing of their electricity consumption.

EnviroCentre INTERROGATORY #7 List 1

Interrogatory

Does the Applicant have any evidence indicating that the installation of fixed CDM measures, including Smart Grid compliant appliance and weatherization programs, can achieve better results than programs based simply on behavioral change?

Response

Once fixed CDM measures have been installed they remain in effect for the life of those measures while behavioural change can be short or long lived. However, Hydro One does not have any evidence indicating that fixed CDM measures are necessarily better than programs based on behavioural change.

EnviroCentre INTERROGATORY #8 List 1

Interrogatory

Is the Applicant concerned about a potential tripling of rate-based CDM charges in 2012 and does it believe that capacity to deliver such programs can be tripled within one year? (Page 1, GEP)

Response

Hydro One's Green Energy Plan indicates CDM spending of >$60 million over 3 year period from 2012-2014, which is the same as the >$20 million per year shown for 2010 and 2011. These expenditures are expected to be funded from Global Adjustment and not from distribution rates. Hydro One has no concerns with completing the forecast CDM program levels.

EnviroCentre INTERROGATORY #9 List 1

Interrogatory

The GEGEA requires the Board to assess licensed distributors to fund CDM and renewable energy programs aimed at specific income sectors of Ontario. How does the Applicant's GEP respond to this requirement *vis-à-vis* low-income consumers?

Response

Please see response provided at Exhibit H, Tab 5, Schedule 1. In addition, the Minister of Energy and Infrastructure has issued a letter to the OEB dated September 8, 2009 advising the OEB to suspend its consultations on the Low-Income Energy Assistance Program (LEAP), pending ministerial direction.

EnviroCentre INTERROGATORY #10 List 1

Interrogatory

The Applicant acknowledges that if its existing CDM programs are recovered through its rates, they are estimated to increase by 2% in 2010 and that the impact on bills is estimated to be 0.7%. Could the Applicant confirm this would mean that a customer paying $100 a month could expect to pay about $0.70 more a month for CDM programs?

Response

The cost of CDM programs are currently recovered from the OPA, and in turn from all electricity consumers in the Province via Global Adjustment. If the costs were to be recovered directly through its rates, Hydro One confirms that a 0.7% impact on total bill does mean that a customer paying $100 a month could expect to pay about $0.70 more a month.

EnviroCentre INTERROGATORY #11 List 1

Interrogatory

Could the Applicant provide evidence on the average monthly amount being paid by electricity customers through rates to fund CDM programs in other parts of North America or would it agree that most rate-based CDM programs require customers to pay an average of $3.00 to $5.00 more a month through a specific charge on their bills?

Response

Hydro One is not in a position to provide evidence on the average monthly amount being paid by electricity customers in other parts of North America nor to confirm that most rate-based CDM programs require customers to pay an average of $3 to $5 a month through a specific charge on their bills.

EnviroCentre INTERROGATORY #12 List 1

Interrogatory

The Applicant believes that its "necessary, used, and useful" Smart Grid investments are appropriate costs to be included in its rate base. Does the Applicant attribute the same qualities to its annual investments of $20 million in CDM and, if so, how does it justify not requiring its customers to pay through their rates for these benefits? (Page 27, GEP)

Response

Hydro One believes that the primary benefit of CDM is the avoided cost of generation which will benefit all electricity consumers in Ontario and therefore it is appropriate that all customers should pay. Hydro One has, and will continue, to follow all applicable guidelines and regulations with respect to the recovery of the cost of its CDM programs.

EnviroCentre INTERROGATORY #13 List 1

Interrogatory

Can the Applicant provide evidence on the potential of expanding its Owen Sound Smart Zone pilot to more of its customers, and of expanding it to include capital investments in Smart Grid compliant appliances in the social housing properties that it serves? (Page 29, GEP)

Response

Please see Exhibit H, Tab 12, Schedule 44 for more information regarding the Smart Zone Pilot and Exhibit H, Tab 12, Schedule 46 regarding the RFP process. The Smart Grid plan includes a number of business scenarios. "Scenario E – Customer Enablement" includes such things as technology/products including, but not limited to, two-way communicating programmable thermostats, IHDs and remote appliance controllers (such as smart appliance controllers, multi purpose gateways, etc.). The Owen Sound location was chosen because it has a broad representation of Hydro One customers including, farm, seasonal, rural and urban. Once scenario solutions have been tested in the Smart Zone, and a business case has been approved for viable options, Hydro One will begin to roll out to remaining parts of the province, including potentially any social housing projects served.

EnviroCentre INTERROGATORY #14 List 1

Interrogatory

The Applicant is not planning any capital investments in CDM from 2010 to 2014. Does this mean that the Applicant sees no role for decentralized capital investments in the homes and businesses of its customers that would reduce the inefficiencies of distributing electricity from centralized sources or is the Applicant reluctant to have such investments allocated to its rates? (Page 1, GEP)

Response

Hydro One's expectation is that CDM programs will be funded from Global Adjustment and therefore such expenditures, whether of a capital nature or not, will not be included in its rates.

EnviroCentre INTERROGATORY #15 List 1

Interrogatory

Is the Applicant aware of any decentralized CDM capital investment programs of other utilities in North America and, if so, can the Applicant provide evidence on the nature and size of such programs?

Response

Hydro One does not have any evidence to provide with regards to any decentralized CDM capital investment programs of other utilities in North America.

EnviroCentre INTERROGATORY #16 List 1

Interrogatory

The Applicant distributes electricity to about 1.3 million customers across Ontario and is seeking approval of at least $20 million for its CDM programs in 2010. Nova Scotia Power distributes electricity to about 483,000 customers across Nova Scotia and is seeking approval of $23 million for its CDM programs in 2010. How does the Applicant explain this difference?

Response

Hydro One has estimated spending on CDM programs in 2010 to be at least $20 million which will be funded by the LDC Fund administered by the OPA. Hydro One has not asked for approval of such funds as part of its distribution rate hearing.

Hydro One is not in a position to comment on Nova Scotia Power's CDM expenditure levels.

EnviroCentre INTERROGATORY #17 List 1

Interrogatory

The Applicant's GEP assumes that the OPA will continue to coordinate and fund CDM programs through the GAM but acknowledges that it may be required to fund CDM programs through its rates. Would the Applicant prefer to design its own CDM programs and does it believe that other organizations have more capacity and credibility to deliver such programs to its customers?

Response

Should Hydro One be directed to design its own programs as part of the process to operationalize the Green Energy and Green Economy Act objectives, then it will do so. However, the OPA currently provides the only access distributors have to funding from the Global Adjustment Mechanism to deliver CDM programs. Hydro One understands that the GEGEA anticipates an additional avenue whereby distributors will have access to the Global Adjustment Mechanism, one where costs incurred to deliver CDM programs approved by the Board are recovered from the Global Adjustment mechanism through the IESO.

Hydro One believes that distributors should be the primary delivery agent for CDM programs and looks forward to designing, developing and delivering CDM programs for its customers.

Power Workers' Union (PWU) INTERROGATORY #1 List 1

Interrogatory

Issue: 1.3: Is service quality, based on the OEB specified performance indicators, acceptable?

Ref (a): Exhibit A, Tab 4, Schedule 1, Page 18, Figure 3

Ref (b): Exhibit A, Tab 4, Schedule 1, Page 20, Figure 5

Ref (c): Exhibit A, Tab 15, Schedule 1, Page 10, Table 2 - Service Reliability Indicators

Ref (d): EB-2007-0681 - Exhibit H, Tab 6, Schedule 1, Page 1, PWU Interrogatory Response

Questions:

1) Ref (a) indicates that SAIFI has deteriorated in 2007 and 2008. HONI states that this deterioration was due to a shift in the customers impacted by storms in 2007 and 2008 compared to 2005 and 2006. Please explain.

2) Ref (b) indicates that defective equipment was responsible for 27% of SAIFI for the period 2005-2008, which is a significant amount. Please indicate if this situation could be improved by improving HONI's equipment and pole maintenance and replacement programs and increased funding for the programs.

3) Ref (c) provides a list of OEB reliability targets for 2006 to 2011. It is understood that HONI's definition of the targets for reliability indicators is based on sections 15.2.1, 15.2.2 and 15.2.3 of the 2006 Electricity Distribution Rate Handbook, which states: "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."

   a) Accordingly, HONI appears to use the largest value (the poorest performance indicator) of the three previous years as its target. Why does HONI consider that the achievement of the worst allowable performance to be an acceptable benchmark?

   b) How does this practice in 'a' above encourage HONI to strive for improved service quality/reliability year over year?

4) In Ref (c), please clarify how HONI's SAIFI, SAIDI and CAIDI OEB targets are arrived at relative to the performance indicator values for the previous three years?

5) Ref (c) and Ref (d), one can obtain the following about the actual SAIFI results for the period 2002 to 2008:

Performance Measure	2002 Act	2003 Act	2004 Act	2005 Act	2006 Act	2007 Act	2008 Act
SAIFI	2.9	2.9	3.1	2.9	2.9	3.6	3.5

Given that performance for the 5-year period between 2002 and 2006 ranged from 2.9 to 3.1, is it reasonable for HONI to increase its "OEB Targets" (to lower its performance target) for 2008 and 2009, which is **≤ 3.6 ,** on the basis of the 2007 actual performance alone?

Response

1) In 2005 and 2006 there were 87 storm days affecting 2.6 million customers. This increased to 105 storm days affecting 3.4 million customers in 2007 and 2008 which resulted in the increase in SAIFI for 2007 and 2008.

2) Yes, improved programs and increased equipment and pole maintenance funding could reduce equipment-related interruptions within limits due to other offsetting factors like weather. Please also refer to interrogatory response in Exhibit H, Tab 1, Schedule 21.

3)

a) As stated, the values are based on the methodology set out in the 2006 Electricity Distribution Rate Handbook. The evidence filed at Exhibit A, Tab 15, Schedule 1, Page 8, line 11 to Page 10, line 8 provides an explanation regarding the variance from the OEB target for 2007 and 2008. The evidence does not offer an opinion on the Rate Handbook methodology

b) Hydro One reports the values based on the 2006 Electricity Distribution Rate Handbook methodology. Hydro One's "STRATEGIC PLAN The Five Year Vision 2009-2014" establishes the framework for improving service quality/reliability year over year.

4) The evidence filed at Exhibit A, Tab 15, Schedule 1, Page 8, line 15 states " Estimate target based on the 2006 Electricity Distribution Rate Handbook to take the largest value of the past three years". This is how the targets were determined.

5) The target is based on the Rate Handbook methodology. The Five Year Vision is to be in the first quartile of comparable utilities.

Power Workers' Union (PWU) INTERROGATORY #2 List 1

Interrogatory

Issue 1.5: Is the overall increase in 2010 and 2011 revenue requirement reasonable given the impact on consumers?

Ref (a): Exhibit C1, Tab 2, Schedule 5, Page 11, Lines 17-25

Question:

1. Ref (a) indicates that the Board has announced its intention that Ontario distribution companies introduce a Low Income Energy Assistance Program ("LEAP"), which is expected to be funded through Distributor's OM&A costs. HONI states that such costs are not included in the Customer Care 2010 and 2011 test year costs as information was not available at the time the HONI business plan was prepared. Please provide any update in this regard since the preparation of HONI's business plan.

Response

Hydro One participated on two OEB Working Groups this summer, to recommend programs for the Financial Assistance and Conservation initiatives of the proposed Low-Income Energy Assistance Program.

Work related to LEAP has since ceased. On September 29, 2009, the Ontario Energy Board issued an update on the Board's Low-Income Energy Assistance Program. The Board is not proceeding further to implement programs for low-income energy consumers, following notice from the Minister of Energy and Infrastructure indicating that the Ministry is in the process of planning to implement a province-wide integrated program for low-income energy consumers, as they move forward with the Green Energy and Green Economic Act.

The LEAP funding required to be recovered through the Distributor's OM&A costs remains unknown at this time and is therefore not included in Hydro One Distribution's Customer Care costs for 2010 and 2011.

Power Workers' Union (PWU) INTERROGATORY #3 List 1

Interrogatory

Issue 3.1: Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Ref (a): Exhibit C1, Tab 2, Schedule 7, Page 20, Table 9 - Corporate Security Functions

Ref (b): Exhibit A, Tab 16, Schedule 1, Page 5, Table 1

Question:

1. Ref (a) indicates that the total costs in 2010 and 2011 are $2.7 million and $2.8 million respectively of which $1.4 million and $1.5 million were allocated to Distribution in 2010 and 2011, respectively. HONI also states that in the last decade there has been a dramatic increase in the focus on the protection of critical infrastructure and the industries that comprise these key social, safety and security functions due to the recognition of the criticality for electricity delivery assets and global and domestic terrorist activities.

   a) Please describe the measures HONI has taken to improve security for its assets and employees.
   b) Please describe whether the historical and planned expenditure amounts on security have been sufficient to achieve this goal that is critical in the reliable delivery of electricity.

2. In Ref (b), please explain the significant increase in the level of Total Incremental Cost Savings attained in 2009 compared to the 2007 and 2008 amounts?

Response

1.

a) Corporate Security has implemented a number of measures to improve security to better protect Hydro One assets and employees. The primary measures include a security incident reporting and response process, employee security and safety awareness training, threat intelligence gathering and security and asset risk assessments; conducting investigations (eg. criminal acts against Hydro One property; information systems and cyber investigations and theft of power); security advice and assistance to Hydro One staff regarding - security systems and asset protection; and performing security infrastructure capital investment business planning and project management.

b) The historical expenditures were not sufficient to implement all of the primary security measures identified in part (a). Overall planned funding, especially as it relates to increasing our capacity to detect and reduce theft of power and provide Hydro One staff with clear – real time – direction and advise regarding the hazards associated with electrical bypasses now provides Hydro One with better resource options to achieve the goal of reliable delivery of electricity.

2. In 2009 we started to realize portions of the cost savings resulting from the implementation of phase 1 of the Cornerstone project.

   We also started to realize non-Cornerstone related cost savings through the initiatives of the smart meter project.

Power Workers' Union (PWU) INTERROGATORY #4 List 1

Interrogatory

Issue 3.2: Is the 2010/2011 vegetation management budget appropriate?

Ref (a): Exhibit C1, Tab 2, Schedule 2, Page 35, Lines 21-23

Ref (b): Exhibit C1, Tab 2, Schedule 2, Page 36, Lines 5-6

Ref (c): Exhibit C1, Tab 2, Schedule 2, Page 39, Line 27

Ref (d): Exhibit A, Tab 15, Schedule 2, Attachment 1, Pages 29, 30 & 35

Questions:

1. In Ref (a), HONI states that "To ensure that the implementation does not result in unnecessary costs, a shorter cycle has been introduced in a gradual manner that takes into account the availability of resources."

   Please describe what those "unnecessary costs" are and identify all resource constraints that prevent HONI from a speedy transition to a shorter cycle such as a 5- or 6-year cycle?

3. In Ref (b), HONI states that "Hydro One Distribution is proposing to gradually increase line clearing and brush control accomplishments to 13,500 km in 2010 and 14,300 km in 2011, which is the level of accomplishment that must be maintained to achieve a 7 year cycle."

   a. Please provide historical accomplishments in terms of line clearing and brush control.
   b. How many kilometers would have been required to be cleared to achieve a target of 5- and 6-year cycles and what would have been the cost differential for the 2010 and 2011 test years?
   c. How long would it take HONI to achieve a 3-4 year cycle?

4. In Ref (c), it is indicated that "The planned 35% increase in the volume of work will target the rights-of-way contributing most to unreliability on Hydro One Distribution's system, and should make appreciable improvements over time to the benefit of all customers."

   Please identify and explain the reference for the 35% figure above and indicate whether the figure refers to line clearing only or not?

5. In Ref (d), Hydro One 2009 Vegetation Management Benchmarking Study, CN Utility Consulting, Inc. ("CNUC") states that:

   "This long cycle is undeniably contributing to higher per unit costs depicted in the charts provided in this report. In relation to the other utilities, it is CNUC' s opinion that Hydro One is working a remediation program. Re-growth and new starts are abundant over the course of a decade. Long cycles between treatments push the workload on an upwardly exponential curve each time it is managed. When stump re-sprouts and new trees are allowed to grow higher than the shrubs, herbs, and grasses, the trees will extend their height rapidly to the height of the wire causing a need for remediation and unplanned maintenance. ··· Based on reported average cycle lengths, Hydro One is operating on a cycle that is at least twice as long as the peer utilities. The conclusion drawn from this key finding is that Hydro One' s long cycle has resulted in excessive growth that naturally drives unit costs higher than those at utilities employing a shorter cycle."

   The report also found that cycle length, in addition to vegetation density, is responsible for HONI's poor performance in reliability.

   If HONI agrees that in the long-term the cost and reliability benefits of a short cycle is significant, is HONI's concern only on short-term rate impact? If yes, would it not be better to make the necessary investment now in order to improve reliability and save cost in the long-term, which will benefit the ratepayer and find a way to mitigate impacts on rates?

Response

1. As discussed during Hydro One Distribution's previous rate application, the "unnecessary costs" refer to additional expenditures that would need to be incurred as a result of an aggressive and rapid increase in accomplishment levels. To immediately implement a 5 or 6-year cycle, Hydro One Distribution would need to increase accomplishments by approximately 37% for a 6-year cycle or 64% for a 5-year cycle above levels achieved in 2007 and 2008. The effect of such increases on resources includes:

   - The demand that Hydro One Distribution would be placing on the market for skilled forestry contractors in Ontario would place additional upward pressure on contract rates and would increase contract costs beyond what was experienced for contracting arrangements in 2007 and 2008, and well beyond the cost of in-house crews.

   - Contractors would need to be monitored and quality assurance programs would need to be undertaken by qualified staff at an additional cost to the Vegetation

Management Program. This redirection of staff would reduce overall Hydro One in-house capability and productivity.

- Additional staff would need to be trained for job planning and customer contact activities at an additional cost to the program. Furthermore, during this training period staff will not be fully productive.

3.

a. Please refer to Exhibit H, Tab 1, Schedule 34.

b. Cycles of 5 and 6 years would require sustained yearly accomplishments of approximately 20,000 kilometers and 16,700 kilometers respectively. Please refer to Exhibit H, Tab 1, Schedule 161 for additional information.

c. As seen in the 2008 Vegetation Management Program Review filed in EB-2007-0681, Exhibit H, Tab 1, Schedule 14, Attachment C, page 11, a 3-4 year cycle is not an optimal cycle length for Hydro One Distribution. There has not been any analysis done to further investigate a 3-4 year-cycle.

4. The 35% increase is referring to the increase in 2010 expenditures for line clearing with respect to the historic expenditures during 2006 and 2008.

5. No. Hydro One Distribution's concern is not only on short-term rate impact, however, Hydro One is concerned with the impacts of moving immediately to a shorter cycle as discussed in the response to item 1 above.

Power Workers' Union (PWU) INTERROGATORY #5 List 1

Interrogatory

Issue 3.5: Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref (a): Exhibit A, Tab 11, Schedule 1, Attachments 1, 2, 3, 4 (Rating Agency Reports)

Ref (b): Ontario Government Announcement dated September 21, 2009 - "Hydro One to Kick-start Major Transmission Projects". (http://news.ontario.ca/mei/en/2009/09/hydro-one-to-kick-start-majortransmission-projects.html)

Questions:

1. In Ref (a), Standard & Poor's report is over a year old. Please provide an updated report if available.

2. Ref (b) indicates that "About $2.3 Billion will be spent by Hydro One on transmission and distribution projects over the next three years." Please provide the Government's directive/letter to HONI referenced in Ref (b).

3. In Ref (a), all the three Rating Agencies identify "Significant capital expenditure programs" as one of the major challenges facing HONI in the following few years. Similarly, Ref (b) indicates that Ontario is asking HONI to immediately proceed with planning and implementing major transmission and distribution projects across Ontario and that about $2.3 Billion will be spent by HONI on transmission and distribution projects over the next three years.

   a) How does the directive referenced in Ref (b) affect HONI's current application?
   b) How is HONI planning to cope with the additional challenge related to Ref (b) over the significant capital expenditure program challenge identified in Ref (a)?

4. In Ref (a), Attachment 1, Page 6, S&P's report states:

   "Labor force demographics unfavorable Hydro One faces labor demographics that, if not well managed, could pose a material risk to the company's day-to-day operations, and the implementation of its most

> ambitious capital program in two decades. Furthermore, if the regulator does not fully recognize related increases in labor expense, profitability could be negatively affected. Management's strategy is to address this through effective knowledge transfer to new hires, encouraging employee retention, and partnership with educational institutions. The company expects 30% of its workforce to depart in the next few years. This is a North America-wide phenomenon, making it that much more difficult to manage."

Please identify and explain any additional impact of the directive referenced in Ref (b) on the demographic challenge facing HONI?

Response

1. There is no full report update. Please refer to Exhibit A, Tab 11, Schedule 1, Attachment 3 for a research update from Standard & Poor's dated March 13, 2009.

2. Please see government letter in Attachment 1.

3.
   a) The Distribution-related work contained in the government letter issued September 21, 2009, and referenced in Ref (b), is captured in the Green Energy Plan submitted by Hydro One Distribution at Exhibit A, Tab 14, Schedule 2.

   b) Historically Hydro One has been successful in completing its Distribution capital programs. Going forward, the Company has put together a work execution strategy described at Exhibit A, Tab 14, Schedule 8 which recognizes the challenges faced and details the actions Hydro One is taking to ensure it can complete the increasing capital work program.

4. The full impact of these projects is not known presently. There are a number of variables which will impact the number of resources required. That said, there will be a need for additional resources and Hydro One will continue to use a mix of staff to complete the work programs

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Ontario

Filed: October 19, 2009
EB-2009-0096
Exhibit H-6-5
Attachment 1
Page 1 of 5

September 21, 2009

Mr. James Arnett
Chair
Hydro One Inc.
483 Bay Street
15th Floor, North Tower
Toronto ON M5G 2P5

Dear Mr. Arnett:

As you know, our government is committed to increasing renewable energy generation across Ontario and ensuring that the necessary infrastructure is in place to enable it. To that end we have passed the *Green Energy and Green Economy Act, 2009* (GEA) providing a comprehensive framework for developing renewable energy generation in Ontario.

The GEA sets the framework for, among other things, the introduction of a feed-in tariff program for renewable energy. To accommodate the anticipated increase in renewable energy generation associated with a feed-in tariff program, it will be necessary to implement a number of major projects to upgrade the transmission and distribution systems.

In anticipation of this, I understand that the Ontario Power Authority (OPA) and Hydro One have worked together to identify areas of the province that would benefit from specific transmission and distribution upgrades to enable new renewable generation likely to be forthcoming through the feed-in tariff program. These projects are reflected in the attached Schedules. I am pleased that Hydro One has been proactive in planning for this much needed expansion of its transmission and distribution systems, in addition to planning for the development of a smarter grid infrastructure that will enable greater integration of renewables.

Given the immediate importance of the projects shown in the attached Schedules, I would ask that Hydro One complete the following activities in anticipation of the feed-in tariff program and high demand for renewable connections:

…/cont'd

1. Immediately proceed with the planning, development and implementation of Transmission Projects outlined in the attached Schedule A, including seeking approvals for the upgrades as soon as there is a reasonable basis to do so.

2. Collaborate with the OPA in defining the scope of work, including termination points, target capacity, number of lines, technical options and sequencing necessary for the Transmission Projects, as well as collaborating with the Independent Electricity System Operator on System Impact Assessments and reliability impacts.

3. Develop and implement smart grid infrastructure in accordance with upcoming government policy, including establishing novel ways of managing network infrastructure for renewables more efficiently.

4. Given the magnitude of work required to complete the Transmission Projects:
    a. Identify the commercially reasonable opportunities for entering into partnership arrangements with qualified third parties/partners for the execution of the Projects;
    b. Work with the Shareholder to identify commercially reasonable criteria that will be used to select qualified third parties/partners;
    c. Use best efforts to enter into those commercially reasonable arrangements; and,
    d. Identify projects as appropriate where the planning, development and implementation of the project would be better accomplished by a qualified third party other than Hydro One.

5. Provide opportunities for participation in the projects by potentially-affected Aboriginal peoples.

6. Immediately proceed with the planning, development and implementation of upgrades to enable distribution system connected generation, as outlined in the attached Schedule B, including collaborating with the OPA and the Independent Electricity System Operator in defining the scope of work necessary for the transmission facilities to enable distribution system connected generation.

7. Begin planning and preliminary development to explore and preserve options for longer-term, high-capacity, transmission link between Thunder Bay and the Greater Toronto Area, including associated collaboration with the OPA for planning.

8. Subject to Crown oversight, engage in consultations with and, where appropriate, accommodate Aboriginal peoples respecting their section 35 rights of the Canadian *Constitution Act*, potentially affected by transmission and distribution projects listed in the attached Schedules.

.../cont'd

To be clear, I am seeking your cooperation on these matters as a key enabler for the feed-in tariff program to be implemented under the GEA and in order to establish a more modern and reinforced electricity grid in Ontario. In no way does my request relate to the implementation or methods used to carry out the work described in this letter, including following appropriate consultation and approvals processes. In light of that, I would expect that Hydro One will develop a comprehensive implementation plan to achieve these objectives.

Furthermore, in order to be informed about Hydro One's progress toward implementing and meeting these objectives, and in keeping with the purpose of the Memorandum of Agreement between Hydro One and the Shareholder, I request that Hydro One report back to me on a semi-annual basis on planning, development and implementation activities undertaken, and progress made in connection with Transmission and Distribution Projects that will enable the feed-in-tariff program. I would appreciate receiving a first report by no later than the end of November 2009.

I am appreciative of Hydro One's continued leadership in moving towards Ontario's green energy future and look forward to seeing your progress in meeting the government's objectives on transmission and distribution system expansion.

On behalf of the Hydro One Board, would you please confirm your understanding of the above, and your concurrence with all that is contemplated, by signing in the space provided below. Thank you for your prompt attention to these matters.

Sincerely,

George Smitherman
Deputy Premier, Minister

I concur,

James Arnett
Chair of the Board, Hydro One

Enclosures

Schedule A - Transmission Projects

Item #	Project	Key Driver	Target In-Service Year*
Core Transmission (Bulk transmission upgrades)			
1	East-West Tie: Nipigon x Wawa (230 kV)	Bulk Transmission Capability for FIT program	2015
2	North-South Tie: Sudbury Area x Barrie (500 kV)	Bulk Transmission Capability for FIT program	2015
3	Barrie x GTA (500 kV)	Bulk Transmission Capability for FIT program	2015
4	Sudbury Area x Algoma Area (Mississagi Transformer Station, 70km east of Sault Ste. Marie) (500 kV)	Bulk Transmission Capability for FIT program	2014
5	London Area x Sarnia (500 kV or 230 kV)	Bulk Transmission Capability for FIT program	2016
6	Bowmanville x GTA (500 kV)	Bulk Transmission Capability for reliability and FIT program	2016
Enabling Transmission (Local enabler connection lines for renewable clusters)			
7	Goderich Enabler	Connections in anticipation of high renewables demand	2013
8	Manitoulin Island Enabler	Connections in anticipation of high renewables demand	2014
9	Huron South Enabler (Wanstead Transformer Station)	Connections in anticipation of high renewables demand	2016
10	Pembroke Enabler	Connections in anticipation of high renewables demand	2014
11	Parry Sound Enabler	Connections in anticipation of high renewables demand	2015
12	North Bay Enabler and 230 kV Line Upgrade	Connections in anticipation of high renewables demand	2015
13	Thunder Bay Enabler	Connections in anticipation of high renewables demand	2015
Regional Transmission (Regional transmission lines for renewables)			
14	Pickle Lake x Nipigon	Renewables, Reliability, and Load Growth	2013
15	Cornwall x Ottawa	Renewables and load growth	2015
16	Belleville x Napanee (Selby Junction)	Renewables and load growth	2014
17	Chenaux x Arnprior Area (Galetta Junction)	Renewables and reliability	2014
Longer-Term (Post-2016)			
18	Sudbury North (500 kV)	Bulk Transmission Capability for FIT program	2017
19	London x Hamilton Area (500 kV)	Bulk Transmission Capability for FIT program	2020
20	Kenora x Thunder Bay	Bulk Transmission Capability for FIT program	2020

* Scope, sequencing and details of implementation subject to detailed Implementation Plan

Schedule B - Projects to Enable Distribution System Connected Generation

Item #	Project	Target In-Service Year*
Transmission Facilities to Enable Distribution-connected Generation		
1	Install 3 Static Var Compensators in Areas of high FIT Uptake	2012-2014
2	Install up to 7 Enabling Transformer Stations in Areas of High FIT Uptake	2012-2015
3	Upgrade Short Circuit Capability of Toronto Area Stations (Hearn TS, Manby TS, Leaside TS)	2012
4	Install in-line Circuit Breakers at up to 7 Locations to Enable Generation Connections	2012-2015
Distribution		
5	Targeted Dx Enhancements to Support Distributed Generation -10 New Distribution Feeders (in areas of high FIT uptake) -Other Minor Investments	2009-2012
Protection, Control, and Telecom (enabling distributed generation)		
6	DG Connection Cost Reduction -Wide Area Telecommunication Infrastructure -Wide Area Island Detection -Transmission Protection Change for Tap-Connected Generation -Stop-Gap Wireless Remote Trip -GPRS (Cellular) Telemetry -Pulse-signalling Island Detection -OGCC System Changes	2009-2012
7	Protection -Feeder Protection Replacements -Telecom to In-Line Reclosers -TS Bus Protection Replacements	
8	TS Capacity Expansion -Generation Trip and Block Scheme -Automated Generation Dispatch System -Transfer Protection Replacements -Tapchanger Control Upgrades -OGCC System Changes	
9	Product Quality -Feeder Voltage Regulator Replacement -OGCC System Changes	
10	Bulk System Reliability -Distribution Station SCADA and Protection Upgrades -OGCC System Changes -Load Rejection Systems Modifications	

* Scope, sequencing and details of implementation subject to detailed Implementation Plan

Power Workers' Union (PWU) INTERROGATORY #6 List 1

Interrogatory

Issue 3.5: Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Ref (a): Exhibit C1, Tab 3, Schedule 2, Page 10, Lines 13-18

Ref (b): EB-2008-0272, Transmission Revenue Requirement and Rates 2009 and 2010, Decisions with Reasons, Page 29, Paragraph 4

Questions:

1. Ref (a) indicates that HONI, as directed by the Board in EB-2006-0501 Decision with Reasons, engaged an independent party, Mercer/Oliver Wyman, to submit an independent, testable and repeatable report on compensation cost and *productivity* for Hydro One and comparable companies. This study, "Compensation Cost Benchmarking", was submitted in evidence in EB-2008-0272, Hydro One Transmission's cost of service application for 2009 and 2010 revenue requirement. In Ref (b), however, the Board stated that it "does not accept that the productivity portion of the Mercer Study can be relied on to draw any conclusions on productivity. *All of the key performance indicators have inherent weaknesses due to the fact that none of the data that was collected from the comparators was originally captured with the intent that it would also be used to perform comparative analysis with other companies."*
   [emphasis added]

   Is it HONI's understanding that data on productivity collected from comparators in the above mentioned study was not done with the intention of conducting a comparative analysis? If so, how is this reconciled with the objective of the study established in Ref (a)?

2. In Ref (b), paragraph 3, the Board stated that "Many of the intervenors found fault with the productivity portion of the Mercer Study for one reason or another. The Mercer Study may be illustrative of the challenges associated with performing comparative analysis of this sort."

   How can HONI, going forward, make use of benchmarking studies of any of its expenditure categories without due consideration of productivity, which according to the above statement of the Board, is a significant challenge to make a comparative analysis with other companies?

3. Has Hydro One compared the wage escalations contained in its current collective agreements to data regarding the escalations contained in other Ontario and Canadian collective agreements entered into at or about the same time as compiled by, for example, the Ministry of Labour or Statistics Canada? If so, what does the comparison reveal?

Response

1. As noted in Ref (a) Hydro One, was directed by the Board in EB-2006-0501 Decision with Reasons, to engage an independent party, to submit an independent, testable and repeatable report on compensation cost and productivity for Hydro One and comparable companies. This study, "Compensation Cost Benchmarking", was submitted in evidence in EB-2008-0272, Hydro One Transmission's cost of service application for 2009 and 2010 revenue.

   It is Hydro One's understanding that Mercer/Oliver Wyman brought to the study their expert knowledge on the subject and used their understanding of the data to draw the conclusions they did. It was based on this reputation as experts that Hydro One selected Mercer/Oliver Wyman to conduct the study.

2. Benchmarking has been used as a performance improvement tool for over thirty years and is well established in most industries.

   However Benchmarking experts all agree that studies of this type are a significant challenge. It is because of this that experienced consultants are used and Hydro One has developed its own expert benchmarking capabilities.

3. Yes, Hydro One has compared the wage escalation in the PWU collective agreement to data in the public sector and utility sector. The PWU's wage adjustment of 3.0% in 2008 is below the 3.5% average annual percentage wage adjustment for major public sector settlements (Source: HRSDC Strategic Policy, Analysis and Workplace Information Directorate), the 3.1% increase for all public sector settlements (Source: Ontario Ministry of Labour) and the 3.3% increase for settlements in the Transportation, Communication and Utilities sector (Source: Ontario Ministry of Labour).

Power Workers' Union (PWU) INTERROGATORY #7 List 1

Interrogatory

Issue 4.2: Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Ref (a): Exhibit D1, Tab 3, Schedule 3, Page 2, Table 1 - Summary of Net Development Capital

Ref (b): Exhibit D1, Tab 3, Schedule 3, Page 22, Line 12-15

Ref (c): Exhibit D1, Tab 3, Schedule 3, Page 24, Line 1

Questions:

1. Does the Net Development Capital breakdown in Ref (a) reflect proposed amendments to the Distribution System Code issued by the Board on June 5, 2009 and subsequently updated on September 11, 2009 (proceeding EB-2009-0077)?

2. In Ref (b), HONI states that the Smart Grid requires substantial cost and expert resources; it is a relatively new concept, and its implementation requires the use of systems that have not been previously deployed.

   a) Is Hydro One aware of any collaboration among Ontario's distributors/ transmitters and other organizations in such areas as research & development and technology transfer which can accelerate implementation as well as reduce overall cost to the province? If yes, please describe Hydro One's role and provide a status update of any such collaboration.

3. Ref (c) makes a reference to "CDM Controllers", which HONI plans to implement as part of its Smart Grid program. Please describe what they are.

Response

1. Yes

2.

   a) Yes, Hydro One is aware of collaboration among Ontario's distributors / transmitters and other organizations. For collaboration on energy storage where Hydro One is a stakeholder, please refer to Exhibit H, Tab 1, Schedule 93 (e). Hydro One is also involved in other studies and on-going collaboration with several universities (University of Western Ontario and the University of

Waterloo for Distribution Studies), CEA Technologies Inc (CEATI) as well as the Ontario Centre of Excellence (OCE).

3. Customer Demand Management (CDM) controllers are devices that are installed in the homes of customers that can communicate with the meter. As a result, the customer can set certain parameters using an interface (usually web based) to turn devices on or off at certain times or to set levels (e.g. temperature).

Power Workers' Union (PWU) INTERROGATORY #8 List 1

Interrogatory

Issue 4.3: Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Ref (a): Exhibit D1, Tab 3, Schedule 8, Page 6, Table 3 - Total Security Infrastructure Capital Expenditures

Question:

1. Given that security infrastructure expenditures are needed to help maintain reliability, reduce power outages and improve employee and public safety, and recognizing that security threats to infrastructure have been public knowledge for a while, please explain why the historic capital expenditures on security infrastructure for 2006, 2007, 2008 & 2009 is nil.

Response

Please refer to response in Exhibit H, Tab 1, Schedule 97.

Power Workers' Union (PWU) INTERROGATORY #9 List 1

Interrogatory

Issue 4.6: Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the distribution system assets and support the O&MA and Capital expenditures for 2010/2011?

Ref (a): Exhibit D1, Tab 2, Schedule 1, Page 7, Table 4.1 - Summary of Priority 1 (P1) ACA Results

Ref (b): Exhibit D1, Tab 2, Schedule 1, Page 17, Lines 1-10

Questions:

1. Ref (a) indicates that about 35% (36,000 km) of rights-of-way are in the "Very Poor" and "Poor" category and are at risk and require clearance work within the next two years.

    a. What is the planned average accomplishment of clearance for 2010 and 2011 in km of lines and what will be the forecast share of vegetation in "Very Poor" and "Poor" categories for 2010 and 2011 considering the fact that some of the vegetation in the "Fair" category will deteriorate to "Very Poor" or "Poor" category?

    b. At the rate of the response to question (a), will HONI be able to accomplish clearance of the 35% vegetation in the "Very Poor" or "Poor" categories?

2. Ref (b) refers to the problem of premature decay of a particular subset of its red pine poles that have been installed between 1997 and 2004.

    a. What year did HONI become aware of the problem?

    b. Is the problem universal to all red pine poles?

    c. The reference indicates that currently, the poles of concern make up approximately 55,000 of the total 1.7 million poles that are in-service. Does the 55,000 figure refer to the total number of red pine poles or red pine poles affected?

    d. Given the safety risks to Hydro One Distribution staff that have to replace these poles, what is HONI's plan to conduct the replacement of these poles expeditiously in order to minimize safety risk?

Response

1.

a. The planned accomplishments for 2010 and 2011 are 13,500 km and 14,300 kilometres respectively. The expectation is that approximately 80% of these kilometers will fall within the "Very Poor" and "Poor" categories.

b. Hydro One Distribution will not be able to accomplish clearance of the 35% of kilometers within 2 years. The outstanding kilometers will be cleared in the following years on a planned basis with the exception of any immediate or excessively high risk locations that will be addressed through off-cycle and unplanned maintenance.

2.

a. In 2006, a high wind event caused several red pine poles to fail. Analysis of the failures identified premature rot in the poles, but it was not until 2008 that a trend was confirmed.

b. No.

c. The 55,000 figure refers to only red pine poles that are affected.

d. Hydro One Distribution will replace substandard red pine poles as their locations are identified through inspections and tests. The replacements will predominantly occur through the Wood Structure Replacement Program as discussed at the bottom of page 21 in Exhibit D1, Tab 3, Schedule 2. Included in the quantities of pole replacements within that program are provisions to replace 500 red pine poles in 2010 and 2,000 poles in 2011. This is an emerging issue, and Hydro One is conducting a study to determine the appropriate rate of replacement of these type of red pine poles relative to the risks of managing a situation that includes an accelerated rate of deterioration.

Power Workers' Union (PWU) INTERROGATORY #10 List 1

Interrogatory

Issue 5.1: Is the proposed Capital Structure and Rate of Return on Equity for Hydro One's distribution business appropriate?

Question:

1. Please provide the Board allowed ROE for HONI for the period 2000-2009.

Response

The Board allowed ROE for Hydro One Distribution per year is as follows:

2000 to 2005	9.88%
2006	9.00%
2007	9.00%
2008	8.57%
2009	8.57%

Power Workers' Union (PWU) INTERROGATORY #12 List 1

Interrogatory

Issue 9.2: Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?

Ref (a): Exhibit A, Tab 14, Schedule 2, Page 2, Paragraph 1

Ref (b): Exhibit A, Tab 14, Schedule 2, Page 18

Ref (c): Exhibit A, Tab 14, Schedule 2, Page 24

Question:

1. In Ref (a), HONI states that:

   Hydro One Distribution assumes that expansion and enabling investments for renewable generation contained in the Plan will be recovered through an external funding mechanism such as the Global Adjustment Mechanism ("GAM"). This assumption reflects the fact that Hydro One Distribution's service territory covers the majority of regions in the Province with high potential for renewable energy generation development, and given that connecting renewable energy generation benefits all load customers in the Province, it is not appropriate for Hydro One Distribution's customers to bear those costs alone. The Plan further assumes that Conservation and Demand Management ("CDM") program costs will also be externally funded through a GAM.

   Since HONI prepared/filed the current application, there have been legislative developments relating to the *Green Energy and Green Economy Act, 2009* ("GEGEA").. Please describe how these developments affect HONI's evidence and assumptions indicated above.

2. What is the rate and average customer bill impact in 2010 and 2011 that is solely attributable to the Green Energy Plan filed by HONI in the current application?

Response

1. The updated pre-filed evidence filed with the Board on September 25, 2009 reflected the proposed Distribution System Code amendments issued by the Board on June 5, 2009 and subsequently updated on September 11, 2009, as well as the new Ontario Regulation 330/09 which came into effect on September 9, 2009 and deals with cost recovery under Section 79.1 of the OEB Act, 1998. The referenced paragraph from page 2 of the Green Energy Plan has been updated to reflect the two items noted above, although the ideas in the quoted reference have not materially changed.

2. The revenue requirement associated with the investments in Hydro One Distribution's Green Energy Plan that are to be recovered through Hydro One Distribution rates have an average rate impact of approximately 1.4% and 0.3% in 2010 and 2011, respectively. The average customer total bill impacts are estimated to be 0.5% and 0.1% in 2010 and 2011, respectively.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #1 List 1

Interrogatory

Issue: #1.4

Reference: Exhibit A/Tab 2/Schedule 1, page 1

a) Please indicate where in the application Hydro One Networks outlines the rationale and implications of its proposal to implement the 2010 and 2011 rate changes on January 1st of each year, as opposed to May 1st.

b) Please fully explain why a January 1st implementation date, as opposed to a May 1st implementation date, is required.

c) Please provide a schedule that sets out:
- The forecast (kWh) sales to customers by month for 2010 and 2011
- The anticipated distribution revenue in the months of January 2010 to April 2010 based on the proposed 2010 rates as opposed to Hydro One Networks current rates
- The anticipated distribution revenue in the months of January 2011 to April 2011 based on the proposed 2011 rates as opposed to the proposed 2010 rates.

Response

a) See response to Exhibit H, Tab 1, Schedule 6

b) See response to Exhibit H, Tab 1, Schedule 6

c) Provided below are the forecasted sales kWh, by month, for 2010 and 2011.

Month	Sales kWh	% of Total
1-Jan-10	2,448,397,952	10.5%
1-Feb-10	2,144,938,183	9.2%
1-Mar-10	2,179,706,385	9.4%
1-Apr-10	1,794,192,607	7.7%
1-May-10	1,692,512,841	7.3%
1-Jun-10	1,718,695,729	7.4%
1-Jul-10	1,828,383,484	7.8%
1-Aug-10	1,833,097,151	7.9%
1-Sep-10	1,646,896,351	7.1%
1-Oct-10	1,784,498,902	7.7%
1-Nov-10	1,941,249,704	8.3%
1-Dec-10	2,291,171,799	9.8%
Total	**23,303,741,087**	

Month	Sales kWh	% of Total
1-Jan-11	2,431,552,544	10.5%
1-Feb-11	2,130,215,461	9.2%
1-Mar-11	2,164,700,703	9.4%
1-Apr-11	1,781,879,761	7.7%
1-May-11	1,680,888,774	7.3%
1-Jun-11	1,706,910,218	7.4%
1-Jul-11	1,815,796,746	7.8%
1-Aug-11	1,820,458,758	7.9%
1-Sep-11	1,635,522,830	7.1%
1-Oct-11	1,772,183,420	7.7%
1-Nov-11	1,927,907,608	8.3%
1-Dec-11	2,275,437,295	9.8%
Total	**23,143,454,117**	

The revenue increase Hydro One will experience as a result of higher rates proposed in this application becoming effective 4 months earlier is approximately $44.3M in 2010 (please refer to Exhibit H, Tab 1, Schedule 7) and $42.5M in 2011.

Description ($M)	**2010**	reference	**2011**	reference
Rates Revenue Requirement	1,101.4	a *	1,215.5	f *
Less: Revenues at prior year rates	981.8	b	1,100.6	g
Full Year Revenue Increase	119.6	c = a - b	114.9	h = f - g
Forecasted Load Jan to Apr per above tables	37%	d	37%	i
Revenue Impact	44.3	e = c x d	42.5	j = h x i

* Exhibit E1, Tab 1, Schedule 1, Attachment 1

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2 List 1

Interrogatory

Issue: #1.1

Reference: Exhibit A/Tab 6/Schedule 1, page 1

- The evidence states that the Application is "substantially consistent" with 2006 EDR Handbook and the Board's Filing Requirements. Please provide a schedule setting out those areas where Hydro One Networks is not consistent.

Response

No.	Exhibit[1]	Item	Reasoning
1	Rate Base	Applicant's capitalization policy and any changes to that policy should be presented as part of capital budget evidence. (Ref.: 2.3.5 Capital Expenditures)[1]	See H-1-64 (bi)
2	Rate Base	Continuity statements should be reconciled to the calculated depreciation expenses and presented by asset account (Ref.: 2.3.3 Accumulated Depreciation)[1]	Largely provided at D2-3-1 and D2-3-2 except for "by asset account"
3	Rate Base	The applicant must provide a three year forecast of capital expenditures (Test Year plus two subsequent years) (Ref.: 2.3.6 Asset Management Plan)[1]	H1 has provided two test years, and 3rd year in confidence in the Business Planning Board Memo's
4	Operating Revenue	Load Forecasts (e.g., average consumption) by Rate Class (Ref.: 2.4.1 Load and Revenue Forecasts and 2.4.2 Variance Analysis)[1]	Hydro One files on a revenue requirement basis. Revenue Requirement by rate class is filed at G1-3-1 and load forecast data by rate class is filed at G1-5-1.
5	Operating Costs	Purchase of Non-Affiliate Services (Ref.: 2.5.6 Purchase of Non-Affiliate Services)[1]	Not practical given the volume and number of monthly transactions and H1's work-based approach

No.	Exhibit[1]	Item	Reasoning
6	Operating Costs	Breakdown of total salaries, wages, benefits charged to OM&A (Ref.: 2.5.4 Employee Compensation Breakdown)[1]	See part (b)(iv) of H-10-40 (Work-based approach does not allow for split out of Distribution information)
7	Operating Costs	Depreciation, Amortization and Depletion by asset group for Historical, Bridge and Test Years (Ref.: 2.5.7 Depreciation/Amortization/Depletion)[1]	Could provide upon request.

[1] OEB's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications amended on May 27, 2009

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3 List 1

Interrogatory

Issue: #1.2 and #5.2

Reference: Exhibit A/Tab 3/Schedule 1, page 2

a) The evidence states (lines 27-28) that the ROE and "other Cost of Capital parameters" will be updated to reflect the September 2009 Consensus forecast and Bank of Canada data available in October 2009 as part of the Draft Rate Order for 2010 rates". Please indicate what "other cost of capital parameters" Hydro One Networks proposes to update based on the October 2009 data.

Response

a) Hydro One Networks is proposing to update both ROE and the deemed short-term rate to reflect the September 2009 Consensus forecast and Bank of Canada data available in October 2009 as part of the Draft Rate Order for 2010 rates.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 3/Schedule 1, page 7

a) The evidence states (lines 11-12) that "growth in customer demand" is one of the reasons for the increase in revenue requirement. However, Exhibit A/Tab 14/Schedule 4, page 19 indicates that demand has been decreasing since 2006 and is projected to decrease further in 2010 and 2011. Please reconcile.

Response

a) Exhibit A, Tab 3, Schedule 1, page 7, line 11 & 12 should have stated "This expansion is required to meet growth in customer connections, …" instead of "This expansion is required to meet growth in customer demand, …".

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5 List 1

Interrogatory

Issue: #2.2

Reference: Exhibit A/Tab 3/Schedule 2, page 5

a) The evidence states that the Cost of Sales for 2008 was higher due, in part, to the Ohio Storm Assistance provided. Please provide a schedule that sets out the cost of the assistance that was provided and the revenues received from Ohio for the assistance.

Response

a) Below is a schedule of costs incurred and revenue received relating to the Electrical Service Restoration Assistance in the aftermath of Hurricane Ike in the state of Ohio.

	Cost	Revenue
Amounts	$2,448,636	$2,726,061

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6 List 1

Interrogatory

Issue: #1.5

Reference: Exhibit A/Tab 3/Schedule 2, pages 4-6

a) Please provide a schedule that sets out for 2008 the Board approved and actual values for Hydro One Networks' Distribution Business for the following items:
   1. kWh sales
   2. Distribution Revenues (from Base Distribution Rates)
   3. Other Revenues (excluding deferral account refund/recoveries and smart meter rate adder)
   4. OM&A Expense (including taxes other than Capital and Income)
   5. Depreciation Expense
   6. Capital and Income Taxes
   7. Interest Expense
   8. Rate Base
   9. Equity Component of Rate Base
   10. Net Income (Please explain if different from 2+3-4-5-6-7)
   11. ROE

Response

$M	Board Approved[1]	Actuals[2]
1. kWh Sales (GWh)[3]	38,411.0	37,634.7
2. Distribution Revenues ($M)	985.8	1004.0
3. Other Revenues ($M)	42.3	47.0
4. OM&A Expense $(M)	466.3	478.0[4]
5. Depreciation Expense $(M) [5]	229.5	266.0
6. Capital and Income Taxes ($M)	43.0	72.0
7. Interest Expense ($M)	143.7	119.0
8. Rate Base ($M)	4,247.4	4203.3[6]
9. Equity Component of Rate Base ($M)	1,699.0	1681.3[6]
10. Net Income ($M)	145.6	116.0
11. ROE ($M)	145.6	116.0

[1] As per EB-2007-0681 – Hydro One Networks' 2008 Distribution Rate Application – Draft Rate Order (January 12th, 2009).
[2] As per Exhibit A, Tab 9, Schedule 1, Attachment 3 – 2008 Distribution Financial Statements.
[3] Shown as GWH for presentation purposes. This includes Market Participants.
[4] OM&A amount shown excludes capital tax but includes Smart Meters.
[5] Includes amortization expense.
[6] Hydro One Distribution does not calculate rate base using historical amounts, however, the use of 2008 amounts are for illustrative purposes.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7 List 1

Interrogatory

Issue: #1.2

Reference: Exhibit A/Tab 4/Schedule 1, page 3
Exhibit A/Tab 16/Schedule 1, page 6

a) Are the Hydro One Networks' Strategic Objectives and associated 5-year goals currently used for planning purposes the same as those used for the 2008 Rate Application? If not, please identify and explain any changes.

b) What is the time frame for the five-year period?

c) Please provide a schedule that sets out the results for each strategic objective for 2006 to 2008 inclusive.

d) With respect to the objective to achieve top quartile unit costs, please indicate:
- What pool of distribution utilities Hydro One Networks is comparing itself to?
- What "unit costs" are being compared?

Response

a) In January 2009, Hydro One refined its Corporate Strategic Objectives by making more visible and explicit the company's commitment to continuous innovation as well as staff recruitment and knowledge transfer. The strategic objectives common in years 2006 through 2008 include: Financial, Reliability, Customer Satisfaction, Safety. Table 1 shows the commonality between the 2009 objectives with the 2008 objectives. The results of the strategic objectives common in years 2006 through 2008 were generally on plan.

Table 1

2008			2009		
Business Value		**2010 Performance Target**	**Strategic Objectives**	**Five-Year Vision**	**Performance Measure/Indicator**
Safety	Focus on cultural change to create and maintain an injury-free workplace.	Zero serious injuries and zero serious near misses	Injury-Free Workplace	Achieve zero lost-time injuries	Lost Time Injuries
Customer Service	Become a more customer-focused company. Improve customer satisfaction. Build relationships with large and mid-size customers that reflect their commercial requirements.	90% customer satisfaction in all major segments	Satisfying Our Customers	90% Customer Satisfaction	Customer Satisfaction (Six Customer Segments)
			Continuous Innovation	Develop and meet Smart Grid goals	Fully Enabled Smart Meters
Reliability	Maintain or improve reliability and service standards in the distribution system while expanding the system to meet Ontario's future needs.	First quartile distribution reliability (like with like comparison)	Reliable, Distribution Systems	Achieve top-quartile distribution reliability (like with like)	Dx Duration of Customer Interruptions
			Protecting the Environment	Reduce our environmental footprint through oil spill management and greenhouse gas reduction	Oil Spill
					Greenhouse Gas Reduction
Employees	Manage the challenges of labour demographics, productivity improvement, development of skills and retention of critical staff.	Attract, develop and retain productive employees	Recruitment Knowledge Transfer	Achieve and maintain top-quartile employee engagement	Employee Survey
Share-holder	Maintain an effective borrowing capability through stable credit quality, and deliver stable financial returns.	Allowed regulated return on equity	Shareholder Value	Achieve the ROE allowed by the Ontario Energy Board and maintain "A" credit rating category	Net Income After Tax
		Top quartile employee productivity			
		Maintain "A" credit rating			Credit Rating
		Top quartile capital/operating efficiency			
			Productivity	Achieve top-quartile unit costs in Distribution	Distribution Unit Cost – Capital and O&M Costs per km

b) The 5-year time frame during which these objectives are used for planning is 2010 – 2014

c) Refer to Exhibit H, Tab 1, Schedule 2.

d) The comparisons will be with peer Canadian and US distribution utilities. The pool of distribution utilities can vary year over year depending on the participation of individual distribution utilities within the benchmarking community. The primary unit-costs for distribution is measured as Capital and O&M costs per km of line.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8 List 1

Interrogatory

Issue: #1.3

Reference: i) Exhibit A/Tab 4/Schedule 1, page 18, lines 11-12
ii) Exhibit A/Tab 4/Schedule 1, pages 19-20

a) With respect to reference (i), please explain how the deterioration in the SAIFI performance for 2007 and 2008 is "due to a shift in the customers impacted by storms in 2007 and 2008 compared to 2005 and 2006".

b) With respect to Figures 4 and 5, what types of events are captured under Unknown/Other?

c) Please provide a schedule that for each year (2005-2008) sets out the contribution to SAIDI (i.e., Hours of Interruption) attributed to:
- Tree Contacts
- Force Majeure - Tree Contacts
- Defective Equipment
- Unknown/Other

d) Please provide a schedule that for each year (2005-2008) sets out the contribution to SAIFI (i.e., Number of Interruptions) attributed to:
- Tree Contacts
- Force Majeure - Tree Contacts
- Defective Equipment
- Unknown/Other

Response

a) Please refer to Exhibit H, Tab 6, Schedule 1.

b) Unknown/Other interruptions are customer interruptions with no apparent cause that contributed to the outage. For example a customer interruption could have been due tree branches contacting the line or animal contact on the line where there is no evidence of the contact which caused the protective device to operate.

c) See table below:

	2005 SAIDI	2006 SAIDI	2007 SAIDI	2008 SAIDI
Tree Contacts	2.5	1.9	2.5	3.1
FM - Tree Contact	5.4	16.2	1.3	10.7
Defective Equipment	2.9	2.5	2.9	2.3
Unknown/Other	0.7	0.7	0.5	1.0

d) See table below:

	2005 SAIFI	2006 SAIFI	2007 SAIFI	2008 SAIFI
Tree Contacts	0.6	0.5	0.7	0.7
FM - Tree Contact	0.6	1.1	0.2	0.8
Defective Equipment	1.0	1.0	1.1	0.8
Unknown/Other	0.5	0.7	0.6	0.8

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9 List 1

Interrogatory

Issue: #3.4

Reference: Exhibit A/Tab 8/Schedule 3, pages 5-6

a) Please provide a schedule that sets out for each service the costs retained by Hydro One Networks for 2009, 2010 and 2011.

b) With respect to the response to part (a), if the overall proportion retained by Hydro One Networks changes materially in 2010 and 2011 relative to 2009 please explain why.

c) The proportion of Financial Services charged to Hydro One Inc. declines significantly in 2010 and 2011 relative to that charged to Remotes and Telecom – please explain why.

d) The proportion of Financial Services charged to Brampton increases significantly in 2010 and 2011 (when compared to 2009) – please explain why.

Response

a) The table below shows the costs retained by Hydro One Networks for 2009-2011 (in $ millions) using the same cost categories that are used in Table 2 of Exhibit A, Tab 2, schedule 3:

Description	**2009**	**2010**	**2011**
General Counsel & Secretary	25.7	29.1	29.8
Financial Services	35.8	32.7	33.9
Corporate Services	19.6	37.2	58.3
Telecommunication Services	20.1	20.1	20.6
Other Services	117.9	126.4	128.6
Total	**219.1**	**245.5**	**271.2**

b) The increase in the amounts retained by Hydro One Networks in 2010 and 2011 results from work expansion in CCFS as referenced in Exhibit C1, Tab 2, Schedule 7, page 2 and higher and higher Inergi outsourcing costs.

c) The decline from 2009 in Hydro One is due to lowered allocation of taxation services. The change in the charges to Telecom and Remotes result from lowered costs in 2010

and 2011 as the IFRS implementation and Cornerstone Phase 2 projects near completion.

d) The increased proportion of 2010 and 2011 fees payable for Financial Services by Brampton is driven primarily by higher compliance and Bill 198 work in the current application.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10 List 1

Interrogatory

Issue: #3.4

Reference: i) Exhibit A/Tab 8/Schedule 3, pages 5-7
ii) EB-2008-0272, Exhibit A/Tab 9/Schedule 2, pages 5-6

a) Please explain why the 2010 fees payable by Hydro One Inc. for Financial Services have declined significantly ($57 vs. $18) from one Application to the next.

b) Please explain why the 2010 fees payable by Brampton for Financial Services have increases significantly ($267 vs. $465) from one Application to the next.

c) Please explain the significant increase in 2010 fees for Corporate Services charged to Remotes and Telecom from one Application to the next; while the charges to Brampton are virtually unchanged.

d) Why, in the current Application, are there are no fees payable by Telecom for Telecom Fibre Lease and Maintenance Agreement as there were in EB-2008-0272?

Response

a) The 2010 fees payable to Hydro One Inc. for Financial Services reflects a lowered assessment of taxation service support to Hydro One Inc.

b) The increase in 2010 fees payable for Financial Services by Brampton is driven primarily by higher compliance and Bill 198 costs and a relatively higher assessment to Brampton compared to the previous allocation as a result of the update of time allocation percentages in the current application.

c) The increase in 2010 fees for Corporate Services charged to Remotes and Telecom are related to higher Human Resources (HR) costs as referenced in Section 1.3 of Exhibit C1, Tab 2, Schedule 7. Since Brampton has its own HR department, the increased Hydro One Networks costs for HR do not convey to Brampton.

d) The Telecom Fibre Lease and Maintenance agreement is applicable only to Transmission and consequently is not included with the current Distribution application.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #11 List 1

Interrogatory

Issue: Issue #3.4

Reference: Exhibit A/Tab 8/Schedule 3, pages 3 and 7

a) Please revise Table 3 so that it also includes the fees payable by Networks to Remotes for services provided per Appendix G.

Response

a) The amount payable by Networks to Remotes for services provided per Appendix G has not been quantified because these services are on an as-needed basis. Hydro One Networks is not planning to utilize such services in 2010/2011.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #12 List 1

Interrogatory

Issue: Issue #3.4

Reference: Exhibit A/Tab 8/Schedule 3 – Appendices

a) Are there any fundamental changes in the services Hydro One Networks either receives from its affiliates or provides to its affiliates from what was outlined in Service Agreements filed in EB-2008-0272? If yes, please describe all such changes.

b) For each of the changes outlined in part (a), please indicate how the Corporate Cost Allocation methodology (Exhibit C1/Tab 5) has been revised to accommodate the change.

Response

a) There are no fundamental changes in the services Hydro One Networks either receives from its affiliates or provides to its affiliates from what was outlined in Service Agreements filed in EB-2008-0272.

b) Please refer to part a).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #13 List 1

Interrogatory

Issue: #2.1

Reference: i) Exhibit A/Tab 12/Schedule 1, page 9
ii) OPA Publication – 2007 Final Conservation Results
http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6563&SiteNodeID=139&BL_ExpandID=

a) Please provide a schedule setting out the OPA sponsored CDM initiatives that Hydro One Networks participated in for the years 2006, 2007, 2008 and 2009 (to date).

b) Please provide a schedule that sets out the participation by Hydro One Networks' Distribution customers by year for each of the programs identified in response to part (a). Please provide any estimates Hydro One Networks or the OPA has developed regarding the kW or kWh savings attributable to this participation by Hydro One Networks' Distribution customers.

c) The OPA has verified the results for six of its 2007 programs. Please provide a schedule (similar to Table 4 in reference (ii)) setting out the contribution of Hydro One Networks' distribution customers to savings reported for each "verified" program. Note: For purposes of the responses please distinguish between Hydro One Networks' retail distribution customers and its embedded Directs and LDCs.

d) For any of the other six 2007 OPA programs that Hydro One Networks participated in please provide an estimate of the 2007 savings and the full year 2008 savings attributable to Hydro One Networks' distribution customers, based on the most current assumptions available from the OPA regarding per participant savings, free-ridership, etc.

Response

a) Please refer to Exhibits H, Tab 4, Schedules 1 through 4.

b) Please refer to Exhibits H, Tab 4, Schedules 1 through 4.

c) Please refer to the table below. Distinction between Hydro One Networks' customers and its embedded Directs and LDCs is not available.

2007 OPA Verified Programs – Hydro One's Allocated Share					
	Technology	**Participants**	**Peak Demand Savings (MW)**	**Annual Energy Savings (GWh)**	**Net Lifetime Savings (GWh)**
2007 Every Kilowatt Counts	Coupons	850,390	1.5	40.5	325.4
2007 Great Refrigerator Roundup	Appliances	13,448	0.7	5.4	47.0
2007 Hot & Cool Savings Rebate	Rebates	49,196	13.8	9.3	139.1
2007 Summer Savings	Households	247,154	12.9	23.3	41.7
2007 Toronto Comprehensive – Building Operators & Managers Association (BOMA)	Information not available to Hydro One				
2007 Demand Response 1 Program	Information not available to Hydro One				

d) Please refer to Exhibits H, Tab 4, Schedules 2 and 3.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #14 List 1

Interrogatory

Issue: #3.8

Reference: Exhibit A/Tab 12/Schedule 2, pages 2-3

a) Please confirm that Hydro One Networks' adoption of the amendments to the CICA Handbook regarding income taxes does not have any impact on the calculation of income taxes for purposes of establishing the 2010 or 2011 proposed revenue requirements? If it does, please explain the impact.

Response

Confirmed. The adoption of the amendments to the CICA Handbook regarding income taxes did not impact the 2010 and 2011 proposed revenue requirements.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #15 List 1

Interrogatory

Issue: #1.2 and #4.6

Reference: Exhibit A/Tab 14/Schedule 1, page 2

a) Please provide copies of the Business Plan instructions issue Q1-2009 and the Business Plan approved in June 2009.

Response

Please refer to Exhibit H, Tab 13, Schedule 1.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #16 List 1

Interrogatory

Issue: #1.2

Reference: i) Exhibit A/Tab 14/Schedule 1, Appendix A, page 1 and Schedule 3, pages 2-3
ii) Exhibit A/Tab 14/Schedule 4, pages 6-7

a) What is the source and date of issue for the Provincial GDP, Provincial Population, Provincial Housing, Commercial Output and Industrial Production forecasts presented in reference (ii)?

b) Please compare the economic growth assumptions used by Hydro One Networks with the most recent projections made by the Provincial Government and the Bank of Canada.

c) Given the ongoing changes in economic conditions worldwide, is Hydro One Networks aware of any other recent projections of economic activity for 2009-2011? If so, please provide.

d) With respect to page reference (i), is Hydro One Networks aware of any more recent projections of inflation, cost escalation and exchange rates for 2009, 2010 and 2011? If yes, please provide.

Response

a) Provincial GDP and Provincial Housing forecasts are based on consensus forecast prepared by Hydro One in March 2009 using forecast from Global Insight, Conference Board, University of Toronto, Centre for Spatial Economics, major banks (CIBC, BMO, RBC, Scotia, TD, Desjardins) and economic outlook contained in the 2009 Ontario Budget report. Provincial population, commercial output forecast and industrial production forecast are based on forecast prepared by Global Insight released in February 2009. The commercial output and industrial production numbers were scaled by Hydro One to be consistent with the consensus GDP forecast.

b) The following table provides the comparison.

Comparison of GDP Forecast (%)

Year	Hydro One[1]	Bank of Canada[2]	Ontario Government[3]
2009	-2.5%	-2.3%	-2.5%
2010	2.3%	3.0%	2.3%
2011	3.5%	3.5%	3.3%

Notes:
(1) Hydro One's forecast pertains to Ontario GDP prepared in March 2009 (Exhibit A, Tab 14, Schedule 4, page 6)
(2) Bank of Canada' s forecast pertains to Canadian GDP released in July 2009
(3) Ontario Government's forecast pertains to Ontario GDP released in March 2009

c) The consensus forecast for Ontario GDP prepared by Hydro One in September 2009 shows -3.3%, 2.2% and 3.7% for 2009, 2010 and 2011 respectively. The consensus forecast for Ontario housing starts Prepared by Hydro One shows 50,000 units, 57,000 units and 67,000 units for 2009, 2010 and 2011 respectively.

d) Please see Exhibit H, Tab 1, Schedule 12. and Exhibit H, Tab 3, Schedule 1.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #17 List 1

Interrogatory

Issue: #1.2

Reference: i) Exhibit A/Tab 14/Schedule 1, Appendix A, pages 1-2
ii) Exhibit A/Tab 14/Schedule 3, pages 3-6

a) With respect to the methodology used for determining distribution interest capitalization rates, please provide more details on precisely what information is obtained from www.pcbond.com (Reference (ii), page 6).

b) With respect to the methodology used for determining distribution interest capitalization rates, please provide, for each of the most recent 12 months, the actual 10-year Government of Canada bond yield, the average DEX mid-term corporate bond index yield and the resulting spread.

c) Please compare Hydro One Networks' forecast interest capitalization rate for 2009 with the rates the OEB has prescribed for 2009.

d) With respect to the methodology used to determine Hydro One Networks' Bond Rates for 2009-2011, please update the Hydro One's credit spreads based on the most recent month's data available.

e) What is the sensitivity of Hydro One Networks' proposed 2010 and 2011 distribution revenue requirements to:
- A 100 basis point change in forecast long-term interest rates. (Note: Please exclude any impact on ROE or short-term interest rates used in determining the cost of capital)
- A 100 basis point change in the forecast interest capitalization rate for 2009-2011.
- A 10 cent change in the forecast exchange rate (CDN$ per US$)?

Response

a) The information that is obtained is the average yield for applicable month for the DEX Mid Term Corporate Bond Index, which is inferred from the yield graph for the index available from the www.pcbond.com website (ie. click on "view graph" on the webpage which provides the closing figures for the DEX Mid Term Corporate Bond Index). A subscription to PC-Bond would be required in order to obtain exact data values.

b) The following table provides for each of the most recent 12 months, the actual 10-year Government of Canada bond yield, the average DEX mid-term corporate bond index yield and the resulting spread.

	10 Year Government of Canada Bond Yield (%)	Average DEX Mid-Term Corporate Bond Index Yield (%)	Resulting Spread (%)
October 2008	3.67	6.50	2.83
November 2008	3.57	6.70	3.13
December 2008	2.95	6.75	3.80
January 2009	2.81	6.75	3.94
February 2009	2.96	6.65	3.69
March 2009	2.89	6.55	3.66
April 2009	2.95	6.25	3.30
May 2009	3.20	5.75	2.55
June 2009	3.46	5.30	1.84
July 2009	3.43	5.20	1.77
August 2009	3.46	4.80	1.34
September 2009	3.37	4.70	1.33

c) The 2009 forecasted interest capitalization rate is 6.93%.

The rates the OEB has prescribed for 2009 are 6.61% for Q1, 6.61% for Q2, 5.67% for Q3 and 4.66% for Q4.

d) Please refer to response to Exhibit H, Tab 3, Schedule 27 for updated Hydro One Networks credit spreads and bond rates for 2009 to 2011, based on most recent forecasts and data.

e) The impact on revenue requirement of changing the long-term forecasted interest rates by 100 basis points in 2010 and 2011 is approximately $2.8M and $7.1M, respectively.

The impact on revenue requirement of changing the forecasted interest capitalization rate by 100 basis points between 2009 and 2011 is approximately $0.4M in 2010 and $0.8M in 2011.

As discussed on lines 15 to 17 of page 3 of Exhibit A, Tab 14 Schedule 3, the exchange rate forecast is not directly used to forecast costs or other variables, it is an important variable affecting the performance of the Canadian and Ontario economies.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #18 List 1

Interrogatory

Issue: #9.1

Reference: Exhibit A/Tab 14/Schedule 2, pages 1-12

a) Please confirm whether or not the Hydro One Distribution Green Energy Plan outlined in this section is meant to meet the requirements of Section 70 (2.1) – part 2 of the recently amended OEB Act.

b) Under Section 70 (2.1) of the Act a licensed distributor is required to prepare plans, in the manner and at the times mandated by the Board or as prescribed by regulation and to file them with the Board for approval for,

i. the expansion or reinforcement of the licensee's transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and

ii. the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

Given this context, why does the plan included a CDM component?

Response

a) Yes.

b) Hydro One Distribution wanted to ensure that its Green Energy Plan met the objectives set out in the government's *Green Energy and Green Economy Act* (GEGEA). The GEGEA objectives for the electricity sector include:

- Fostering the growth of renewable energy projects; and
- Promoting and expanding energy conservation in Ontario

Therefore, Hydro One believed it prudent to include a CDM component in its Green Energy Plan, while recognizing that there is still considerable work required to operationalize the GEGEA with respect to CDM. In any case, Hydro One assumes that CDM program costs will continue to be externally funded, similar to the funding currently provided by the Ontario Power Authority, and as such CDM is not part of the costs being sought for recovery in this proceeding.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #19 List 1

Interrogatory

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 1-12

a) With respect to page 7 (Updated), are the numbers shown for each year cumulative or the values for that specific year?

b) With respect to updated page 8 (lines 15-25) and page 9 (lines 16-28), please provide more details regarding the methodology that will be used to determine whether the investments required to provide for new renewable energy generators are economic.

c) With respect to updated page 14, are the OM&A costs shown for the period 2012-2014 an annual value or the total for the period? Does the same response apply to the 2012-2014 capital costs shown on pages 15 19 and 23?

d) Why isn't any of the OM&A spending considered to be eligible for External Funding through the GAM?

Response

a) The numbers are cumulative.

b) Please refer to Exhibit H, Tab 2, Schedule 2.

c) Both OM&A and Capital costs shown for the period 2012-2014 are the total for the period.

d) Please refer to Exhibit H, Tab 9, Schedule 55 with respect to Smart Grid related OM&A spending.

With respect to Renewable Energy Generation related OM&A spending, as discussed in Exhibit H, Tab 10, Schedule 19, Hydro One plans to continue leveraging the expertise of existing departments to handle generation connection related development work. In addition, the on-going OM&A costs associated with maintaining the portion of Expansion and REI capital investments to be funded by all customers in Ontario are assumed to be negligible over the test year period. Therefore Hydro One does not propose recovering this spending through an external funding mechanism.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #20 List 1

Interrogatory

Issue: #9.1 and #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 15-19 (Updated)

a) The costs associated with Investment Summaries D27, D28 and D29 total more than the Gross Capital Costs set out in the table on page 19. For each of the three investment summaries, please identify precisely what activities and costs (gross and net) are incorporated in the proposed Green Energy Plan under the category "Expansion of the Distribution System to Connect Renewable Energy Generation".

b) On page 10 (lines 8-10) Hydro One Networks notes that for the purpose of establishing its proposed spending on Expansion it has identified regions where the potential for renewable energy generation is the highest. Please provide a schedule that sets out these regions and for each region identifies i) the renewable energy generation potential and how it was determined, ii) the costs included in each of D27, D28 and D29 by region and iii) the specific types of investment activities targeted for each region/area (i.e., with reference to the types of activities listed on page 16).

c) For each of the three regions/areas with the highest capital spending requirements, please provide copies of the assessments/analysis undertaken to identify the Expansion spending required to support renewable energy generation.

d) With respect to Investment Summaries D27-D29 in Exhibit D1/Tab 3/Schedule 3, please confirm that the Recoverable costs shown include the anticipated recoveries from the Global Adjustment mechanism as well as those recoverable from Generators? Please reconcile the Recoverable Costs reported in D27-D29 with the Externally Funded Capital reported on page 19.

e) Pages 16-17 discuss the "expansion" of the distribution system to connect renewable energy generation. Under the current proposed amendments to the DSC renewable generators will be responsible for cost of "expansions" in excess of the renewable energy expansion cost cap. Given this context, does the external funding shown on page 19 include any "contributions" from Generators? If not, why not? If yes, please provide a breakout for each year.

Response

a) For each investment summary document (ISD) D27, D28 and D29 the gross capital costs included in the Green Energy Plan are the totals shown on the line labeled "Capital and Minor Fixed Assets (A)". The split of the D27, D28 and D29 gross capital costs between the Connection, Expansion and Renewable Enabling Improvement categories is provided in the response at Exhibit H, Tab 1, Schedule 89 (for D27), Exhibit H, Tab 1, Schedule 90 (for D28) and Exhibit H, Tab 1, Schedule 91 (for D29). Note that a correction to the numbers shown in the prefiled evidence for ISD D29 is provided in the response at Exhibit H, Tab 1, Schedule 91.

b) Hydro One currently does not have a detailed forecast of renewable generation connection by MW and region. However, it is expected that the regions where potential for renewable energy generation is the highest are those regions that do not fall within the Orange or Yellow Zones designated by the Ontario Power Authority.

c) Hydro One currently does not have the requested analysis by region.

d) Yes this is confirmed. Reconciliation of the recoverable costs for expansion work is provided below:

	2010	2011	Reference
Externally funded expansion costs for D27	14.6	13.7	Per Table 4 in Exhibit D1-3-3 and Exhibit H-1-89
Externally funded expansion costs for D28	18.1	31.5	Per Table 4 in Exhibit D1-3-3 and Exhibit H-1-90
Externally funded expansion costs for D29	25.9	71.2	Per Table 5 in Exhibit D1-3-3 and Exhibit H-1-91
Externally funded expansion costs for other small projects (under $1M)	1.4	1.7	Part of "Other Generation Connections Work" in Table 4 in Exhibit D1-3-3
Externally Funded Capital per Table on page 19 of Green Energy Plan	60	118	

e) No, the external funding shown on page 19 does not include any contributions from generators. Generator contributions are not included because the costs of all the expansions covered by the Green Energy Plan are assumed to fall within the $90,000 per MW cost cap.

Sections 3.2.5A and B of the DSC state that capital contributions are not required if the expansion investment is in an OEB approved plan. As such, Hydro One's view is that any costs for expansion assets that exceed the $90,000 per MW cost cap, since they were not considered in the Green Energy Plan, would be borne by the generator.

Hydro One's Green Energy Plan is the first such plan to be reviewed by the Board. Hydro One anticipates that the Board, in the course of this proceeding, will provide additional guidance and clarity on the basis for allocating the costs identified in the plan.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #21 List 1

Interrogatory

Issue: #9.3

Reference: Exhibit A/Tab 14/Schedule 2, pages 16-19

a) Please reconcile the 1% (net) load growth used to determine load growth benefits with the fact that the load forecast presented in Exhibit A/Tab 14/Schedule 4, page 19 is declining from 2008 to 2011. If the 1% is only applied to certain areas of the Province, please provide a schedule that sets out those areas experiencing load growth and those that are not with the relevant load increases/decreases by area that reconcile with an overall annual decrease in provincial load. On the same schedule, please identify which areas are included in the Green Energy Plan for purposes of Expansion Investment (consistent with the response to Question #20, part (b)).

b) Please provide the complete analysis supporting the 3% Load Growth benefit factor (page 19).

c) Was the calculation of the 15% Asset Replacement benefit factor done on an area by area basis taking into account the specific investment activities proposed in the Plan for each area (page 18)?

d) If the response to part (c) is yes, please provide the analysis for the two areas that contribute the most to the total gross capital investment on Expansions.

e) If the response to part (c) is no, please provide the complete analysis supporting the 15% benefit factor.

Response

a) The 1% load growth used to determine load growth benefit criteria was based on a long term load growth forecast for the whole Province over the next 20 years rather than short term forecast from 2008 to 2011. This was done to determine how many feeders may be overloaded during the 20 years, not to identify the specific feeders that could be overloaded.

b) The following assumptions were used for load growth analysis:

   a. Planned generation-driven Expansion projects would provide benefit for only 20% of the investments required in areas experiencing load growth

b. Load growth is 1% per year over the next 20 years
c. Average length of new feeder/feeder modification required for each overloaded feeder is 5km per feeder
d. Unit cost of new feeder/feeder modification is $300k per km

Attachment 1 shows the feeder loading information and the investments driven by load growth over the next 20 years. The cost of building new feeders or feeder modifications for any future year can be obtained using:

Actual # overloaded feeders to be fixed * 5km/feeder * $300k/km

Page 9 of the Attachment 1 shows the NPV of the load growth-driven work calculated based on the above formula. With the first assumption of 20% probability, the load growth percentage benefit is then obtained using:

$$\frac{\text{NPV of load growth driven work} * 20\%}{\text{NPV of DG related feeder expansion}}$$

c) No.

d) Not applicable.

e) The 15% Asset Replacement benefit factor was done based on the wood pole conditions for the whole Province and did not consider any specific investment activities. The follow assumptions were used for Asset Replacement benefit analysis:

a. Unit cost of new feeder/feeder modification is $300k per km
b. There are 13 poles per km of feeders
c. Pole life is 40 years
d. The average unit pole replacement is $5,800 per pole

Attachment 2 shows the detailed pole age distribution and replacement cost over the next 40 years. Page 3 and 4 of the attachment 2 shows the NPV of the average "consumed portion" of the poles replaced on a "like-for-like" basis in terms of dollar per pole (Pole Consumed Portion). With the first two assumptions, the asset replacement percentage benefit is then obtained using:

$$\frac{\text{Pole Consumed Portion (\$/pole)} * 13\text{ (poles/km)}}{300\text{ (\$/km)}}$$

			Voltage (kV)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPV-Feeder Expansion (Dx) $23,837,000	#of overloaded feeders for		13.8	3																					
	#of overloaded feeders for		22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPV-Feeder Expansion (DG) $166,217,000	#of overloaded feeders for		25	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
	#of overloaded feeders for		27	3		1				2						1							1	1	
	#of overloaded feeders for		44	7		3					1	1				3		1			2	1	1		
	Total#of overloaded feeders	33		13	0	4	0	0	0	2	1	1	1	0	0	4	0	1	0	0	2	1	2	1	
	Acutal # overloaded feeders to be fixed	33		0	0	3	3	2	2	2	2	2	2	2	2	4	0	1	0	0	2	1	2	1	
% benefit for Dx per DG invest 2.9	km feeders required for modification	165		0	0	15	15	10	10	10	10	10	10	10	10	20	0	5	0	0	10	5	10	5	
	cost of new/modified feeders	49500		0	0	4500	4500	3000	3000	3000	3000	3000	3000	3000	3000	6000	0	1500	0	0	3000	1500	3000	1500	

					Peak Load (MW)																					
STATION	STATION kV	Provincial Lines Zone	Lines Operations Centre	FEEDER	Now	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Murray TS	115	2 West Cei	LINCOLN	M10	20.034	20.23434	20.43668	20.64105	20.84746	21.05594	21.26649	21.47916	21.69395	21.91089	22.13	22.3513	22.57481	22.80056	23.02857	23.25885	23.49144	23.72635	23.96362	24.20325	24.44529	24.68974
Murray TS	115	2 West Cei	LINCOLN	M11	4.199	4.24099	4.2834	4.326234	4.369496	4.413191	4.457323	4.501896	4.546915	4.592384	4.638308	4.684691	4.731538	4.778854	4.826642	4.874909	4.923658	4.972894	5.022623	5.072849	5.123578	5.1748138
Murray TS	115	2 West Cei	LINCOLN	M13	1.821	1.83921	1.857602	1.876178	1.89494	1.913889	1.933028	1.952358	1.971882	1.991601	2.011517	2.031632	2.051948	2.072468	2.093193	2.114124	2.135266	2.156618	2.178185	2.199966	2.221966	2.2441857
Murray TS	115	2 West Cei	LINCOLN	M25	17.996	18.17596	18.35772	18.5413	18.72671	18.91398	19.10312	19.29415	19.48709	19.68196	19.87878	20.07757	20.27834	20.48113	20.68594	20.8928	21.10173	21.31274	21.52587	21.74113	21.95854	22.178125
Stanley TS	115	2 West Cei	LINCOLN	M2	0.18	0.1818	0.183618	0.185454	0.187309	0.189182	0.191074	0.192984	0.194914	0.196863	0.198832	0.20082	0.202829	0.204857	0.206905	0.208974	0.211064	0.213175	0.215307	0.21746	0.219634	0.2218305
Thorold TS	115	2 West Cei	LINCOLN	M1	3.284	3.31684	3.350008	3.383508	3.417344	3.451517	3.486032	3.520892	3.556101	3.591662	3.627579	3.663855	3.700493	3.737498	3.774873	3.812622	3.850748	3.889256	3.928148	3.96743	4.007104	4.0471751
Thorold TS	115	2 West Cei	LINCOLN	M2	8.176	8.25776	8.340338	8.423741	8.507978	8.593058	8.678989	8.765779	8.853436	8.941971	9.03139	9.121704	9.212921	9.305051	9.398101	9.492082	9.587003	9.682873	9.779702	9.877499	9.976274	10.076037
Thorold TS	115	2 West Cei	LINCOLN	M3	2.091	2.11191	2.133029	2.154359	2.175903	2.197662	2.219639	2.241835	2.264253	2.286896	2.309765	2.332863	2.356191	2.379753	2.403551	2.427586	2.451862	2.476381	2.501144	2.526156	2.551417	2.5769315
Thorold TS	115	2 West Cei	LINCOLN	M5	0.615	0.62115	0.627362	0.633635	0.639971	0.646371	0.652835	0.659363	0.665957	0.672616	0.679343	0.686136	0.692997	0.699927	0.706927	0.713996	0.721136	0.728347	0.735631	0.742987	0.750417	0.757921
Coniston TS	115	6 Northeas	SUDBURY*	M1	4.9	4.949	4.99849	5.048475	5.09896	5.149949	5.201449	5.253463	5.305998	5.359058	5.412648	5.466775	5.521443	5.576657	5.632424	5.688748	5.745635	5.803092	5.861123	5.919734	5.978931	6.0387205
Coniston TS	115	6 Northeas	SUDBURY*	M5	3.1	3.131	3.16231	3.193933	3.225872	3.258131	3.290712	3.32362	3.356856	3.390424	3.424329	3.458572	3.493158	3.528089	3.56337	3.599004	3.634994	3.671344	3.708057	3.745138	3.782589	3.820415
North Bay TS	115	6 Northeas	NIPISSING	M1	4.076	4.11676	4.157928	4.199507	4.241502	4.283917	4.326756	4.370024	4.413724	4.457861	4.50244	4.547464	4.592939	4.638868	4.685257	4.732109	4.779431	4.827225	4.875497	4.924252	4.973495	5.0232295
Hearst TS	115	6 Northeas	KAPUSKASING	M1	1.94	1.9594	1.978994	1.998784	2.018772	2.038959	2.059349	2.079943	2.100742	2.121749	2.142967	2.164397	2.186041	2.207901	2.22998	2.25228	2.274803	2.297551	2.320526	2.343731	2.367169	2.3908404
Hearst TS	115	6 Northeas	KAPUSKASING	M2	13.69	13.8269	13.96517	14.10482	14.24587	14.38833	14.53221	14.67753	14.82431	14.97255	15.12228	15.2735	15.42623	15.5805	15.7363	15.89366	16.0526	16.21313	16.37526	16.53901	16.7044	16.871446
Kapuskasing TS	230	6 Northeas	KAPUSKASING	M1	5.802	5.86002	5.91862	5.977806	6.037584	6.09796	6.15894	6.220529	6.282735	6.345562	6.409018	6.473108	6.537839	6.603217	6.669249	6.735942	6.803301	6.871334	6.940048	7.009448	7.079543	7.150338
Kapuskasing TS	230	6 Northeas	KAPUSKASING	M3	1.157	1.16857	1.180256	1.192058	1.203979	1.216019	1.228179	1.240461	1.252865	1.265394	1.278048	1.290828	1.303737	1.316774	1.329942	1.343241	1.356673	1.37024	1.383943	1.397782	1.41176	1.4258775
Kapuskasing TS	230	6 Northeas	KAPUSKASING	M4	4.074	4.11474	4.155887	4.197446	4.239421	4.281815	4.324633	4.367879	4.411558	4.455674	4.500231	4.545233	4.590685	4.636592	4.682958	4.729788	4.777085	4.824856	4.873105	4.921836	4.971054	5.0207648
Port Arthur TS #1	115	7 Northwes	THUNDER BAY	M27	1.258	1.27058	1.283286	1.296119	1.30908	1.322171	1.335392	1.348746	1.362234	1.375856	1.389615	1.403511	1.417546	1.431721	1.446039	1.460499	1.475104	1.489855	1.504754	1.519801	1.534999	1.5503491
Port Arthur TS #1	115	7 Northwes	THUNDER BAY	M6	4.543	4.58843	4.634314	4.680657	4.727464	4.774739	4.822486	4.870711	4.919418	4.968612	5.018298	5.068481	5.119166	5.170358	5.222061	5.274282	5.327025	5.380295	5.434098	5.488439	5.543323	5.5987566
Agincourt TS	230	3A Central	BOWMANVILLE*	M1	1.423	1.43723	1.451602	1.466118	1.48078	1.495587	1.510543	1.525649	1.540905	1.556314	1.571877	1.587596	1.603472	1.619507	1.635702	1.652059	1.668579	1.685265	1.702118	1.719139	1.73633	1.7536937
Agincourt TS	230	3A Central	BOWMANVILLE*	M2	1.371	1.38471	1.398557	1.412543	1.426668	1.440935	1.455344	1.469898	1.484597	1.499443	1.514437	1.529581	1.544877	1.560326	1.575929	1.591688	1.607605	1.623681	1.639918	1.656317	1.672881	1.6896094
Allanburg TS	230	2 West Cei	LINCOLN	M6	2.659	2.68559	2.712446	2.73957	2.766966	2.794636	2.822582	2.850808	2.879316	2.908109	2.93719	2.966562	2.996228	3.02619	3.056452	3.087016	3.117887	3.149065	3.180556	3.212362	3.244485	3.2769302
Allanburg TS	230	2 West Cei	LINCOLN	M7	10.89	10.9989	11.10889	11.21998	11.33218	11.4455	11.55995	11.67555	11.79231	11.91023	12.02933	12.14963	12.27112	12.39384	12.51777	12.64295	12.76938	12.89708	13.02605	13.15631	13.28787	13.420748
Allanburg TS	230	2 West Cei	LINCOLN	M8	6.186	6.24786	6.310339	6.373442	6.437176	6.501548	6.566564	6.632229	6.698552	6.765537	6.833192	6.901524	6.97054	7.040245	7.110647	7.181754	7.253571	7.326107	7.399368	7.473362	7.548096	7.6235765
Aylmer TS	115	1 West	AYLMER	M2	3.513	3.54813	3.583611	3.619447	3.655642	3.692198	3.72912	3.766411	3.804076	3.842116	3.880538	3.919343	3.958536	3.998122	4.038103	4.078484	4.119269	4.160461	4.202066	4.244087	4.286528	4.3293929
Beamsville TS	115	2 West Cei	LINCOLN	M2	12.477	12.60177	12.72779	12.85507	12.98362	13.11345	13.24459	13.37703	13.5108	13.64591	13.78237	13.92019	14.0594	14.19999	14.34199	14.48541	14.63026	14.77657	14.92433	15.07358	15.22431	15.376554
Beamsville TS	115	2 West Cei	LINCOLN	M3	11.703	11.82003	11.93823	12.05761	12.17819	12.29997	12.42297	12.5472	12.67267	12.7994	12.92739	13.05667	13.18723	13.31911	13.4523	13.58682	13.72269	13.85991	13.99851	14.1385	14.27988	14.422683
Beamsville TS	115	2 West Cei	LINCOLN	M4	3.72	3.7572	3.794772	3.83272	3.871047	3.909757	3.948855	3.988344	4.028227	4.068509	4.109194	4.150286	4.191789	4.233707	4.276044	4.318805	4.361993	4.405612	4.449669	4.494165	4.539107	4.584498
Bilberry Creek TS	115	4 East	WINCHESTER	M3	8.919	9.00819	9.098272	9.189255	9.281147	9.373959	9.467698	9.562375	9.657999	9.754579	9.852125	9.950646	10.05015	10.15065	10.25216	10.35468	10.45823	10.56281	10.66844	10.77512	10.88287	10.991704
Bilberry Creek TS	115	4 East	WINCHESTER	M4	7.47	7.5447	7.620147	7.696348	7.773312	7.851045	7.929556	8.008851	8.08894	8.169829	8.251527	8.334043	8.417383	8.501557	8.586572	8.672438	8.759162	8.846754	8.935222	9.024574	9.11482	9.2059678
Brant TS	115	2 West Cei	SIMCOE	M14	5.698	5.75498	5.81253	5.870655	5.929362	5.988655	6.048542	6.109027	6.170118	6.231819	6.294137	6.357078	6.420649	6.484856	6.549704	6.615201	6.681353	6.748167	6.815648	6.883805	6.952643	7.0221693
Brant TS	115	2 West Cei	SIMCOE	M21	7.458	7.53258	7.607906	7.683985	7.760825	7.838433	7.916817	7.995985	8.075945	8.156705	8.238272	8.320655	8.403861	8.4879	8.572779	8.658506	8.745092	8.832542	8.920868	9.010077	9.100177	9.1911791
Brant TS	115	2 West Cei	SIMCOE	M22	2.839	2.86739	2.896064	2.925025	2.954275	2.983818	3.013656	3.043792	3.07423	3.104972	3.136022	3.167382	3.199056	3.231047	3.263357	3.295991	3.328951	3.36224	3.395863	3.429821	3.46412	3.4987607
Brantford TS	230	2 West Cei	SIMCOE	M25	13.544	13.67944	13.81623	13.9544	14.09394	14.23488	14.37723	14.521	14.66621	14.81287	14.961	15.11061	15.26172	15.41434	15.56848	15.72416	15.88141	16.04022	16.20062	16.36263	16.52625	16.691516
Brantford TS	230	2 West Cei	SIMCOE	M27	16.542	16.70742	16.87449	17.04324	17.21367	17.38581	17.55967	17.73526	17.91262	18.09174	18.27266	18.45539	18.63994	18.82634	19.0146	19.20475	19.3968	19.59076	19.78667	19.98454	20.18438	20.386227
Brantford TS	230	2 West Cei	SIMCOE	M28	13.419	13.55319	13.68872	13.82561	13.96387	14.1035	14.24454	14.38698	14.53085	14.67616	14.82292	14.97115	15.12087	15.27207	15.42479	15.57904	15.73483	15.89218	16.0511	16.21161	16.37373	16.537467
Buchanan TS	230	1 West	BEACHVILLE	M21	7.096	7.16696	7.23863	7.311016	7.384126	7.457967	7.532547	7.607872	7.683951	7.760791	7.838399	7.916783	7.99595	8.07591	8.156669	8.238236	8.320618	8.403824	8.487862	8.572741	8.658469	8.7450532
Caledonia TS	230	2 West Cei	SIMCOE	M3	13.467	13.60167	13.73769	13.87506	14.01381	14.15395	14.29549	14.43845	14.58283	14.72866	14.87595	15.02471	15.17495	15.3267	15.47997	15.63477	15.79112	15.94903	16.10852	16.2696	16.4323	16.596622
Caledonia TS	230	2 West Cei	SIMCOE	M6	8.4	8.484	8.56884	8.654528	8.741074	8.828484	8.916769	9.005937	9.095996	9.186956	9.278826	9.371614	9.46533	9.559984	9.655583	9.752139	9.849661	9.948157	10.04764	10.14812	10.2496	10.352092
Centralia TS	115	1 West	CLINTON	M1	6.495	6.55995	6.62555	6.691805	6.758723	6.82631	6.894573	6.963519	7.033154	7.103486	7.174521	7.246266	7.318729	7.391916	7.465835	7.540493	7.615898	7.692057	7.768978	7.846668	7.925134	8.0043857
Centralia TS	115	1 West	CLINTON	M2	5.562	5.61762	5.673796	5.730534	5.78784	5.845718	5.904175	5.963217	6.022849	6.083077	6.143908	6.205347	6.267401	6.330075	6.393376	6.457309	6.521882	6.587101	6.652972	6.719502	6.786697	6.854564
Centralia TS	115	1 West	CLINTON	M3	4.775	4.82275	4.870978	4.919687	4.968884	5.018573	5.068759	5.119446	5.170641	5.222347	5.274571	5.327316	5.38059	5.434395	5.488739	5.543627	5.599063	5.655054	5.711604	5.76872	5.826407	5.8846715
Centralia TS	115	1 West	CLINTON	M4	4.234	4.27634	4.319103	4.362294	4.405917	4.449977	4.494476	4.539421	4.584815	4.630663	4.67697	4.72374	4.770977	4.818687	4.866874	4.915543	4.964698	5.014345	5.064488	5.115133	5.166285	5.2179475
Clarke TS	230	1 West	STRATHROY	M2	7.702	7.77902	7.85681	7.935378	8.014732	8.094879	8.175828	8.257586	8.340162	8.423564	8.5078	8.592878	8.678806	8.765594	8.85325	8.941783	9.031201	9.121513	9.212728	9.304855	9.397904	9.4918827
Crosby TS	230	4 East	PERTH	M3	-0.013	-0.01313	-0.01326	-0.01339	-0.01353	-0.01366	-0.0138	-0.01394	-0.01408	-0.01422	-0.01436	-0.0145	-0.01465	-0.0148	-0.01494	-0.01509	-0.01524	-0.0154	-0.01555	-0.01571	-0.01586	-0.0160211
Crosby TS	230	4 East	PERTH	M5	3.121	3.15221	3.183732	3.215569	3.247725	3.280202	3.313004	3.346134	3.379596	3.413392	3.447526	3.482001	3.516821	3.551989	3.587509	3.623384	3.659618	3.696214	3.733176	3.770508	3.808213	3.8462952
Crosby TS	230	4 East	PERTH	M6	3.401	3.43501	3.46936	3.504054	3.539094	3.574485	3.61023	3.646332	3.682796	3.719624	3.75682	3.794388	3.832332	3.870655	3.909362	3.948455	3.98794	4.027819	4.068098	4.108779	4.149866	4.191365
Crowland TS	115	2 West Cei	LINCOLN	M13	5.497	5.55197	5.60749	5.663565	5.7202	5.777402	5.835176	5.893528	5.952463	6.011988	6.072108	6.132829	6.194157	6.256099	6.31866	6.381846	6.445665	6.510121	6.575223	6.640975	6.707385	6.7744585
Crowland TS	115	2 West Cei	LINCOLN	M21	1.544	1.55944	1.575034	1.590785	1.606693	1.62276	1.638987	1.655377	1.671931	1.68865	1.705537	1.722592	1.739818	1.757216	1.774788	1.792536	1.810461	1.828566	1.846852	1.86532	1.883973	1.9028132
Detweiler TS	230	1 West*	LISTOWEL*	M12	8.458	8.54258	8.628006	8.714286	8.801429	8.889443	8.978337	9.068121	9.158802	9.25039	9.342894	9.436323	9.530686	9.625993	9.722253	9.819475	9.91767	10.01685	10.11702	10.21819	10.32037	10.423571

Dundas TS	115	2 West Cei	DUNDAS	M1	4.74	4.7874	4.835274	4.883627	4.932463	4.981788	5.031606	5.081922	5.132741	5.184068	5.235909	5.288268	5.341151	5.394562	5.448508	5.502993	5.558023	5.613603	5.669739	5.726436	5.783701	5.8415378
Dundas TS	115	2 West Cei	DUNDAS	M3	12.999	13.12899	13.26028	13.39288	13.52681	13.66208	13.7987	13.93669	14.07605	14.21681	14.35898	14.50257	14.6476	14.79407	14.94202	15.09144	15.24235	15.39477	15.54872	15.70421	15.86125	16.019863
Dundas TS	115	2 West Cei	DUNDAS	M4	12.958	13.08758	13.21846	13.35064	13.48415	13.61899	13.75518	13.89273	14.03166	14.17197	14.31369	14.45683	14.6014	14.74741	14.89489	15.04384	15.19427	15.34622	15.49968	15.65468	15.81281	15.969335
Dundas TS	115	2 West Cei	DUNDAS	M5	6.488	6.55288	6.618409	6.684593	6.751439	6.818953	6.887143	6.956014	7.025574	7.09583	7.166788	7.238456	7.310841	7.383949	7.457789	7.532367	7.60769	7.683767	7.760605	7.838211	7.916593	7.9957589
Dundas TS	115	2 West Cei	DUNDAS	M6	1.377	1.39077	1.404678	1.418724	1.432912	1.447241	1.461713	1.47633	1.491094	1.506005	1.521065	1.536275	1.551638	1.567154	1.582826	1.598654	1.614641	1.630787	1.647095	1.663566	1.680202	1.6970037
Dundas TS	115	2 West Cei	DUNDAS	M8	4.533	4.57833	4.624113	4.670354	4.717058	4.764229	4.811871	4.85999	4.908589	4.957675	5.007252	5.057325	5.107898	5.158977	5.210567	5.262672	5.315299	5.368452	5.422137	5.476358	5.531121	5.5864327
Dunnville TS	115	2 West Cei	LINCOLN	M2	7.512	7.58712	7.662991	7.739621	7.817017	7.895187	7.974139	8.053881	8.13442	8.215764	8.297921	8.380901	8.46471	8.549357	8.63485	8.721199	8.808411	8.896495	8.98546	9.075314	9.166068	9.2577283
Edgeware TS	230	1 West	AYLMER	M2	9.766	9.86366	9.962297	10.06192	10.16254	10.26416	10.36681	10.47047	10.57518	10.68093	10.78774	10.89562	11.00457	11.11462	11.22577	11.33802	11.4514	11.56592	11.68158	11.79839	11.91638	12.03554
Edgeware TS	230	1 West	AYLMER	M3	5.149	5.20049	5.252495	5.30502	5.35807	5.411651	5.465767	5.520425	5.575629	5.631385	5.687699	5.744576	5.802022	5.860042	5.918643	5.977829	6.037607	6.097984	6.158963	6.220553	6.282759	6.3455861
Edgeware TS	230	1 West	AYLMER	M4	8.986	9.07586	9.166619	9.258285	9.350868	9.444376	9.53882	9.634208	9.73055	9.827856	9.926134	10.0254	10.12565	10.22691	10.32918	10.43247	10.53679	10.64216	10.74858	10.85607	10.96463	11.074274
Elmira TS	115	1 West	LISTOWEL	M2	8.524	8.60924	8.695332	8.782286	8.870109	8.95881	9.048398	9.138882	9.230271	9.322573	9.415799	9.509957	9.605057	9.701107	9.798118	9.896099	9.99506	10.09501	10.19596	10.29792	10.4009	10.504909
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M11	5	5.05	5.1005	5.151505	5.20302	5.25505	5.307601	5.360677	5.414284	5.468426	5.523111	5.578342	5.634125	5.690466	5.747371	5.804845	5.862893	5.921522	5.980737	6.040545	6.10095	6.1619597
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M12	21.985	22.20485	22.4269	22.65117	22.87768	23.10646	23.33752	23.5709	23.8066	24.04467	24.28512	24.52797	24.77325	25.02098	25.27119	25.5239	25.77914	26.03693	26.2973	26.56028	26.82588	27.094137
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M25	6.003	6.06303	6.12366	6.184897	6.246746	6.309213	6.372305	6.436029	6.500389	6.565393	6.631047	6.697357	6.764331	6.831974	6.900294	6.969297	7.03899	7.10938	7.180473	7.252278	7.324801	7.3980488
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M26	9.884	9.98284	10.08267	10.1835	10.28533	10.38818	10.49207	10.59699	10.70296	10.80999	10.91809	11.02727	11.13754	11.24891	11.3614	11.47502	11.58977	11.70566	11.82272	11.94095	12.06036	12.180962
Finch TS	230	2 West Cei	ORANGEVILLE*	M11	4.118	4.15918	4.200772	4.24278	4.285207	4.328059	4.37134	4.415053	4.459204	4.503796	4.548834	4.594322	4.640265	4.686668	4.733535	4.78087	4.828679	4.876966	4.925735	4.974993	5.024743	5.07499
Finch TS	230	2 West Cei	ORANGEVILLE*	M12	11.789	11.90689	12.02596	12.14622	12.26768	12.39036	12.51426	12.6394	12.7658	12.89346	13.02239	13.15261	13.28414	13.41698	13.55115	13.68666	13.82353	13.96176	14.10138	14.2424	14.38482	14.528669
Galt TS	230	2 West Cei	DUNDAS	M12	8.628	8.71428	8.801423	8.889437	8.978331	9.068115	9.158796	9.250384	9.342888	9.436317	9.53068	9.625986	9.722246	9.819469	9.917664	10.01684	10.11701	10.21818	10.32036	10.42356	10.5278	10.633078
Goderich TS	115	1 West	CLINTON	M1	3.807	3.84507	3.883521	3.922356	3.961579	4.001195	4.041207	4.081619	4.122435	4.16366	4.205296	4.247349	4.289823	4.332721	4.376048	4.419809	4.464007	4.508647	4.553733	4.599271	4.645263	4.6917161
Goderich TS	115	1 West	CLINTON	M2	5.249	5.30149	5.354505	5.40805	5.46213	5.516752	5.571919	5.627638	5.683915	5.740754	5.798162	5.856143	5.914705	5.973852	6.03359	6.093926	6.154865	6.216414	6.278578	6.341364	6.404778	6.4688253
Halton TS	230	2 West Cei	DUNDAS*	M21	10.62	10.7262	10.83346	10.9418	11.05121	11.16173	11.27334	11.38608	11.49994	11.61494	11.73109	11.8484	11.96688	12.08655	12.20742	12.32949	12.45279	12.57731	12.70309	12.83012	12.95842	13.088002
Highbury TS	115	1 West	BEACHVILLE	M11	4.05	4.0905	4.131405	4.172719	4.214446	4.256591	4.299157	4.342148	4.38557	4.429425	4.47372	4.518457	4.563641	4.609278	4.655371	4.701924	4.748944	4.796433	4.844397	4.892841	4.94177	4.9911874
Ingersoll TS	230	1 West	BEACHVILLE	M43	13.906	14.04506	14.18551	14.32737	14.47064	14.61535	14.7615	14.90911	15.05821	15.20879	15.36088	15.51448	15.66963	15.82633	15.98459	16.14443	16.30588	16.46894	16.63363	16.79996	16.96796	17.137642
Ingersoll TS	230	1 West	BEACHVILLE	M44	2.403	2.42703	2.4513	2.475813	2.500571	2.525577	2.550833	2.576341	2.602105	2.628126	2.654407	2.680951	2.707761	2.734838	2.762187	2.789808	2.817706	2.845884	2.874342	2.903086	2.932117	2.9614378
Ingersoll TS	230	1 West	BEACHVILLE	M45	6.498	6.56298	6.62861	6.694896	6.761845	6.829463	6.897758	6.966736	7.036403	7.106767	7.177835	7.249613	7.322109	7.39533	7.469283	7.543976	7.619416	7.69561	7.772566	7.850292	7.928795	8.0080828
Ingersoll TS	230	1 West	BEACHVILLE	M46	7.651	7.72751	7.804785	7.882833	7.961661	8.041278	8.121691	8.202908	8.284937	8.367786	8.451464	8.535979	8.621338	8.707552	8.794627	8.882573	8.971399	9.061113	9.151724	9.243242	9.335674	9.4290307
Ingersoll TS	230	1 West	BEACHVILLE	M49	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Ingersoll TS	230	1 West	BEACHVILLE	M50	7.153	7.22453	7.296775	7.369743	7.44344	7.517875	7.593054	7.668984	7.745674	7.823131	7.901362	7.980376	8.060179	8.140781	8.222189	8.304411	8.387455	8.47133	8.556043	8.641603	8.728019	8.8152995
Ingersoll TS	230	1 West	BEACHVILLE	M51	10.189	10.29089	10.3938	10.49774	10.60271	10.70874	10.81583	10.92399	11.03323	11.14356	11.25499	11.36754	11.48122	11.59603	11.71199	11.82911	11.9474	12.06688	12.18755	12.30942	12.43252	12.556841
Ingersoll TS	230	1 West	BEACHVILLE	M52	10.363	10.46663	10.5713	10.67701	10.78378	10.89162	11.00053	11.11054	11.22164	11.33386	11.4472	11.56167	11.67729	11.79406	11.912	12.03112	12.15143	12.27295	12.39568	12.51963	12.64483	12.771278
Jarvis TS	230	2 West Cei	SIMCOE	M2	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Jarvis TS	230	2 West Cei	SIMCOE	M3	5.835	5.89335	5.952284	6.011806	6.071924	6.132644	6.19397	6.25591	6.318469	6.381654	6.44547	6.509925	6.575024	6.640774	6.707182	6.774254	6.841996	6.910416	6.979521	7.049316	7.119809	7.191007
Jarvis TS	230	2 West Cei	SIMCOE	M4	8.114	8.19514	8.277091	8.359862	8.443461	8.527896	8.613175	8.699306	8.786299	8.874162	8.962904	9.052533	9.143058	9.234489	9.326834	9.420102	9.514303	9.609446	9.705541	9.802596	9.900622	9.9996282
Jarvis TS	230	2 West Cei	SIMCOE	M7	0.034	0.03434	0.034683	0.03503	0.035381	0.035734	0.036092	0.036453	0.036817	0.037185	0.037557	0.037933	0.038312	0.038695	0.039082	0.039473	0.039868	0.040266	0.040669	0.041076	0.041486	0.0419013
Keith TS	230	1 West	ESSEX	M3	5.892	5.95092	6.010429	6.070533	6.131239	6.192551	6.254477	6.317021	6.380192	6.443994	6.508434	6.573518	6.639253	6.705646	6.772702	6.840429	6.908833	6.977922	7.047701	7.118178	7.18936	7.2612533
Keith TS	230	1 West	ESSEX	M4	7.191	7.26291	7.335539	7.408894	7.482983	7.557813	7.633391	7.709725	7.786823	7.864691	7.943338	8.022771	8.102999	8.184029	8.265869	8.348528	8.432013	8.516333	8.601496	8.687511	8.774387	8.8621304
Keith TS	230	1 West	ESSEX	M5	5.44	5.4944	5.549344	5.604837	5.660886	5.717495	5.77467	5.832416	5.89074	5.949648	6.009144	6.069236	6.129928	6.191227	6.25314	6.315671	6.378828	6.442616	6.507042	6.572113	6.637834	6.7042122
Kent TS	230	1 West	KENT	M1	10.512	10.61712	10.72329	10.83052	10.93883	11.04822	11.1587	11.27029	11.38299	11.49682	11.61179	11.72791	11.84518	11.96364	12.08327	12.20411	12.32615	12.44941	12.5739	12.69964	12.82664	12.954904
Kent TS	230	1 West	KENT	M15	11.961	12.08061	12.20142	12.32343	12.44666	12.57113	12.69684	12.82381	12.95205	13.08157	13.21239	13.34451	13.47795	13.61273	13.74886	13.88635	14.02521	14.16547	14.30712	14.45019	14.59469	14.74064
Kent TS	230	1 West	KENT	M16	12.532	12.65732	12.78389	12.91173	13.04085	13.17126	13.30297	13.436	13.57036	13.70606	13.84312	13.98156	14.12137	14.26258	14.40521	14.54926	14.69476	14.8417	14.99012	15.14002	15.29142	15.444336
Kent TS	230	1 West	KENT	M17	11.573	11.68873	11.80562	11.92367	12.04291	12.16334	12.28497	12.40782	12.5319	12.65722	12.78379	12.91163	13.04075	13.17115	13.30287	13.43589	13.57025	13.70596	13.84301	13.98144	14.12126	14.262472
Kent TS	230	1 West	KENT	M18	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Kent TS	230	1 West	KENT	M2	7.3	7.373	7.44673	7.521197	7.596409	7.672373	7.749097	7.826588	7.904854	7.983902	8.063742	8.144379	8.225823	8.308081	8.391162	8.475073	8.559824	8.645422	8.731877	8.819195	8.907387	8.9964612
Kingsville TS	115	1 West	ESSEX	M1	6.571	6.63671	6.703077	6.770108	6.837809	6.906187	6.975249	7.045001	7.115451	7.186606	7.258472	7.331057	7.404367	7.478411	7.553195	7.628727	7.705014	7.782064	7.859885	7.938484	8.017869	8.0980474
Kingsville TS	115	1 West	ESSEX	M2	9.362	9.45562	9.550176	9.645678	9.742135	9.839556	9.937952	10.03733	10.1377	10.23908	10.34147	10.44489	10.54934	10.65483	10.76138	10.86899	10.97768	11.08746	11.19833	11.31032	11.42342	11.537653
Kingsville TS	115	1 West	ESSEX	M3	8.513	8.59813	8.684111	8.770952	8.858662	8.947249	9.036721	9.127088	9.218359	9.310543	9.403648	9.497685	9.592661	9.688588	9.785474	9.883329	9.982162	10.08198	10.1828	10.28463	10.38748	10.491353
Kingsville TS	115	1 West	ESSEX	M4	6.982	7.05182	7.122338	7.193562	7.265497	7.338152	7.411534	7.485649	7.560506	7.636111	7.712472	7.789596	7.867492	7.946167	8.025629	8.105885	8.186944	8.268814	8.351502	8.435017	8.519367	8.6045605
Kingsville TS	115	1 West	ESSEX	M5	9.293	9.38593	9.479789	9.574587	9.670333	9.767036	9.864707	9.963354	10.06299	10.16362	10.26525	10.36791	10.47159	10.5763	10.68206	10.78888	10.89677	11.00574	11.1158	11.22696	11.33923	11.452618
Kingsville TS	115	1 West	ESSEX	M6	11.694	11.81094	11.92905	12.04834	12.16882	12.29051	12.41342	12.53755	12.66293	12.78956	12.91745	13.04663	13.17709	13.30886	13.44195	13.57637	13.71213	13.84926	13.98775	14.12763	14.2689	14.411591
Kingsville TS	115	1 West	ESSEX	M7	7.656	7.73256	7.809886	7.887984	7.966864	8.046533	8.126998	8.208268	8.290351	8.373254	8.456987	8.541557	8.626972	8.713242	8.800375	8.888378	8.977262	9.067035	9.157705	9.249282	9.341775	9.4351927
Kingsville TS	115	1 West	ESSEX	M8	9.325	9.41825	9.512433	9.607557	9.703632	9.800669	9.898675	9.997662	10.09764	10.19862	10.3006	10.40361	10.50764	10.61272	10.71885	10.82604	10.9343	11.04364	11.15408	11.26562	11.37827	11.492055
Kingsville TS	115	1 West	ESSEX	M9	9.44	9.5344	9.629744	9.726041	9.823302	9.921535	10.02075	10.12096	10.22217	10.32439	10.42763	10.53191	10.63723	10.7436	10.85104	10.95955	11.06914	11.17983	11.29163	11.40455	11.51859	11.63378
Kleinburg TS	230	3A Central	NEWMARKET	M5	8.649	8.73549	8.822845	8.911073	9.000184	9.090186	9.181088	9.272899	9.365628	9.459284	9.553877	9.649416	9.74591	9.843369	9.941802	10.04122	10.14163	10.24305	10.34548	10.44893	10.55342	10.658958
Kleinburg TS	230	3A Central	NEWMARKET	M6	10.793	10.90093	11.00994	11.12004	11.23124	11.34355	11.45699	11.57156	11.68727	11.80415	11.92219	12.04141	12.16182	12.28344	12.40628	12.53034	12.65564	12.7822	12.91002	13.03912	13.16951	13.301206
Lake TS	230	2 West Cei	LINCOLN*	M1	7	7.07	7.1407	7.212107	7.284228	7.35707	7.430641	7.504947	7.579997	7.655797	7.732355	7.809678	7.887775	7.966653	8.046319	8.126783	8.208051	8.290131	8.373032	8.456763	8.54133	8.6267436
Lake TS	230	2 West Cei	LINCOLN*	M2	7.941	8.02041	8.100614	8.18162	8.263436	8.346071	8.429532	8.513827	8.598965	8.684955	8.771804	8.859522	8.948118	9.037599	9.127975	9.219254	9.311447	9.404561	9.498607	9.593593	9.689529	9.7864244
Lake TS	230	2 West Cei	LINCOLN*	M3	7.67	7.7467	7.824167	7.902409	7.981433	8.061247	8.14186	8.223278	8.305511	8.388566	8.472452	8.557176	8.642748	8.729175	8.816467	8.904632	8.993678	9.083615	9.174451	9.266196	9.358858	9.4524462
Lake TS	230	2 West Cei	LINCOLN*	M4	7.517	7.59217	7.668092	7.744773	7.82222	7.900443	7.979447	8.059241	8.139834	8.221232	8.303445	8.386479	8.470344	8.555047	8.640598	8.727004	8.814274	8.902416	8.991441	9.081355	9.172169	9.2638902
Lake TS	230	2 West Cei	LINCOLN*	M5	7.426	7.50026	7.575263	7.651015	7.727525	7.804801	7.882849	7.961677	8.041294	8.121707	8.202924	8.284953	8.367803	8.451481	8.535996	8.621355	8.707569	8.794645	8.882591	8.971417	9.061131	9.1517425
Lake TS	230	2 West Cei	LINCOLN*	M6	8.009	8.08909	8.169981	8.251681	8.334198	8.417539	8.501715	8.586732	8.672599	8.759325	8.846919	8.935388	9.024742	9.114989	9.206139	9.2982	9.391182	9.485094	9.579945	9.675745	9.772502	9.8702271
Lambton TS	230	1 West	LAMBTON	M1	3.839	3.87739	3.916164	3.955326	3.994879	4.034828	4.075176	4.115928	4.157087	4.198658	4.240644	4.283051	4.325881	4.36914	4.412832	4.45696	4.501529	4.546545	4.59201	4.63793	4.68431	4.7311527
Lambton TS	230	1 West	LAMBTON	M2	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Lambton TS	230	1 West	LAMBTON	M3	4.965	5.01465	5.064797	5.115444	5.166599	5.218265	5.270448	5.323152	5.376384	5.430147	5.484449	5.539293	5.594686	5.650633	5.707139	5.764211	5.821853	5.880072	5.938872	5.998261	6.058244	6.118826
Lambton TS	230	1 West	LAMBTON	M4	15.996	16.15596	16.31752	16.48069	16.6455	16.81196	16.98008	17.14988	17.32138	17.49459	17.66954	17.84623	18.02469	18.20494	18.38699	18.57086	18.75657	18.94413	19.13358	19.32491	19.51816	19.713341
Lambton TS	230	1 West	LAMBTON	M5	10.627	10.73327	10.8406	10.94901	11.0585	11.16908	11.28077	11.39358	11.50752	11.62259	11.73882	11.85621	11.97477	12.09452	12.21546	12.33762	12.46099	12.5856	12.71146	12.83857	12.96696	13.096629
Lambton TS	230	1 West	LAMBTON	M6	3	3.03	3.0603	3.090903	3.121812	3.15303	3.18456	3.216406	3.24857	3.281056	3.313866	3.347005	3.380475	3.41428	3.448423	3.482907	3.517736	3.552913	3.588442	3.624327	3.66057	3.6971758
Lauzon TS	230	1 West	ESSEX	M23	7.519	7.59419	7.670132	7.746833	7.824302	7.902545	7.98157	8.061386	8.142	8.22342	8.305654	8.38871	8.472597	8.557323	8.642897	8.729326	8.816619	8.904785	8.993833	9.083771	9.174609	9.266355

Lauzon TS	230	1 West	ESSEX	M24	12.257	12.37957	12.50337	12.6284	12.75468	12.88223	13.01105	13.14116	13.27257	13.4053	13.53935	13.67475	13.81149	13.94961	14.08911	14.23	14.3723	14.51602	14.66118	14.80779	14.95587	15.105428
Lauzon TS	230	1 West	ESSEX	M25	5.653	5.70953	5.766625	5.824292	5.882534	5.94136	6.000773	6.060781	6.121389	6.182603	6.244429	6.306873	6.369942	6.433641	6.497978	6.562958	6.628587	6.694873	6.761822	6.82944	6.897734	6.9667116
Lauzon TS	230	1 West	ESSEX	M26	11.403	11.51703	11.6322	11.74852	11.86601	11.98467	12.10451	12.22556	12.34782	12.47129	12.59601	12.72197	12.84919	12.97768	13.10745	13.23853	13.37091	13.50462	13.63967	13.77607	13.91383	14.052965
Lauzon TS	230	1 West	ESSEX	M27	8.963	9.05263	9.143156	9.234588	9.326934	9.420203	9.514405	9.609549	9.705645	9.802701	9.900728	9.999735	10.09973	10.20073	10.30274	10.40576	10.50982	10.61492	10.72107	10.82828	10.93656	11.045929
Lauzon TS	230	1 West	ESSEX	M28	5.653	5.70953	5.766625	5.824292	5.882534	5.94136	6.000773	6.060781	6.121389	6.182603	6.244429	6.306873	6.369942	6.433641	6.497978	6.562958	6.628587	6.694873	6.761822	6.82944	6.897734	6.9667116
Lauzon TS	230	1 West	ESSEX	M29	6.789	6.85689	6.925459	6.994713	7.064661	7.135307	7.20666	7.278727	7.351514	7.425029	7.49928	7.574272	7.650015	7.726515	7.80378	7.881818	7.960636	8.040243	8.120645	8.201852	8.28387	8.3667089
Lauzon TS	230	1 West	ESSEX	M4	5.498	5.55298	5.60851	5.664595	5.721241	5.778453	5.836238	5.8946	5.953546	6.013082	6.073212	6.133945	6.195284	6.257237	6.319809	6.383007	6.446837	6.511306	6.576419	6.642183	6.708605	6.7756909
Leslie TS	230	3A Central	NEWMARKET*	M2	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Leslie TS	230	3A Central	NEWMARKET*	M31	11.46	11.5746	11.69035	11.80725	11.92532	12.04458	12.16502	12.28667	12.40954	12.53363	12.65897	12.78556	12.91341	13.04255	13.17297	13.3047	13.43775	13.57213	13.70785	13.84493	13.98338	14.123212
Longwood TS	500	1 West	STRATHROY	M23	5.886	5.94486	6.004309	6.064352	6.124995	6.186245	6.248108	6.310589	6.373695	6.437432	6.501806	6.566824	6.632492	6.698817	6.765805	6.833463	6.901798	6.970816	7.040524	7.110929	7.182039	7.253859
Longwood TS	500	1 West	STRATHROY	M24	6.335	6.39835	6.462334	6.526957	6.592226	6.658149	6.72473	6.791977	6.859897	6.928496	6.997781	7.067759	7.138437	7.209821	7.281919	7.354738	7.428286	7.502569	7.577594	7.65337	7.729904	7.8072029
Longwood TS	500	1 West	STRATHROY	M25	5.232	5.28432	5.337163	5.390535	5.44444	5.498885	5.553873	5.609412	5.665506	5.722161	5.779383	5.837177	5.895549	5.954504	6.014049	6.07419	6.134931	6.196281	6.258244	6.320826	6.384034	6.4478746
Longwood TS	500	1 West	STRATHROY	M26	2.001	2.02101	2.04122	2.061632	2.082249	2.103071	2.124102	2.145343	2.166796	2.188464	2.210349	2.232452	2.254777	2.277325	2.300098	2.323099	2.34633	2.369793	2.393491	2.417426	2.4416	2.4660163
Malden TS	230	1 West	ESSEX	M10	8.72	8.8072	8.895272	8.984225	9.074067	9.164808	9.256456	9.34902	9.44251	9.536936	9.632305	9.728628	9.825914	9.924173	10.02342	10.12365	10.22489	10.32713	10.43041	10.53471	10.64006	10.746458
Malden TS	230	1 West	ESSEX	M11	8.278	8.36078	8.444388	8.528832	8.61412	8.700261	8.787264	8.875136	8.963888	9.053527	9.144062	9.235503	9.327858	9.421136	9.515348	9.610501	9.706606	9.803672	9.901709	10.00073	10.10073	10.20174
Malden TS	230	1 West	ESSEX	M12	4.103	4.14403	4.18547	4.227325	4.269598	4.312294	4.355417	4.398971	4.442961	4.487391	4.532265	4.577587	4.623363	4.669597	4.716293	4.763456	4.81109	4.859201	4.907793	4.956871	5.00644	5.0565041
Malden TS	230	1 West	ESSEX	M7	6.488	6.55288	6.618409	6.684593	6.751439	6.818953	6.887143	6.956014	7.025574	7.09583	7.166788	7.238456	7.310841	7.383949	7.457789	7.532367	7.60769	7.683767	7.760605	7.838211	7.916593	7.9957589
Malden TS	230	1 West	ESSEX	M8	5.65	5.7065	5.763565	5.821201	5.879413	5.938207	5.997589	6.057565	6.11814	6.179322	6.241115	6.303526	6.366561	6.430227	6.494529	6.559475	6.625069	6.69132	6.758233	6.825816	6.894074	6.9630145
Malden TS	230	1 West	ESSEX	M9	8.132	8.21332	8.295453	8.378408	8.462192	8.546814	8.632282	8.718605	8.805791	8.893849	8.982787	9.072615	9.163341	9.254975	9.347524	9.441	9.53541	9.630764	9.727071	9.824342	9.922585	10.021811
Malvern TS	230	3A Central	NEWMARKET*	M35	5.645	5.70145	5.758465	5.816049	5.87421	5.932952	5.992281	6.052204	6.112726	6.173853	6.235592	6.297948	6.360927	6.424537	6.488782	6.55367	6.619206	6.685399	6.752253	6.819775	6.887973	6.9568525
Modeland TS	230	1 West	LAMBTON	M25	12.7	12.827	12.95527	13.08482	13.21567	13.34783	13.48131	13.61612	13.75228	13.8898	14.0287	14.16899	14.31068	14.45378	14.59832	14.74431	14.89175	15.04067	15.19107	15.34298	15.49641	15.651378
Nebo TS	230	2 West Cer	DUNDAS	M3	6.877	6.94577	7.015228	7.08538	7.156234	7.227796	7.300074	7.373075	7.446806	7.521274	7.596486	7.672451	7.749176	7.826667	7.904934	7.983984	8.063823	8.144462	8.225906	8.308165	8.391247	8.4751594
Nebo TS	230	2 West Cer	DUNDAS	M4	11.203	11.31503	11.42818	11.54246	11.65789	11.77447	11.89221	12.01113	12.13124	12.25256	12.37508	12.49883	12.62382	12.75006	12.87756	13.00634	13.1364	13.26776	13.40044	13.53444	13.66979	13.806487
Nebo TS	230	2 West Cer	DUNDAS	M5	5.194	5.24594	5.298399	5.351383	5.404897	5.458946	5.513536	5.568671	5.624358	5.680601	5.737407	5.794781	5.852729	5.911256	5.970369	6.030073	6.090373	6.151277	6.21279	6.274918	6.337667	6.4010437
Nebo TS	230	2 West Cer	DUNDAS	M6	9.19	9.2819	9.374719	9.468466	9.563151	9.658782	9.75537	9.852924	9.951453	10.05097	10.15148	10.25299	10.35552	10.45908	10.56367	10.6693	10.776	10.88376	10.9926	11.10252	11.21355	11.325682
Nebo TS	230	2 West Cer	DUNDAS	M7	11.152	11.26352	11.37616	11.48992	11.60482	11.72086	11.83807	11.95645	12.07602	12.19678	12.31875	12.44193	12.56635	12.69202	12.81894	12.94713	13.0766	13.20736	13.33944	13.47283	13.60756	13.743635
Nebo TS	230	2 West Cer	DUNDAS	M8	8	8.08	8.1608	8.242408	8.324832	8.40808	8.492161	8.577083	8.662854	8.749482	8.836977	8.925347	9.0146	9.104746	9.195794	9.287752	9.380629	9.474435	9.56918	9.664872	9.76152	9.8591355
Norfolk TS	115	2 West Cer	SIMCOE	M1	8.258	8.34058	8.423986	8.508226	8.593308	8.679241	8.766033	8.853694	8.942231	9.031653	9.12197	9.213189	9.305321	9.398374	9.492358	9.587282	9.683154	9.779986	9.877786	9.976564	10.07633	10.177093
Norfolk TS	115	2 West Cer	SIMCOE	M3	6.743	6.81043	6.878534	6.94732	7.016793	7.086961	7.15783	7.229409	7.301703	7.37472	7.448467	7.522952	7.598181	7.674163	7.750905	7.828414	7.906698	7.985765	8.065622	8.146279	8.227741	8.3100189
Norfolk TS	115	2 West Cer	SIMCOE	M4	2.387	2.41087	2.434979	2.459328	2.483922	2.508761	2.533849	2.559187	2.584779	2.610627	2.636733	2.6631	2.689731	2.716629	2.743795	2.771233	2.798945	2.826935	2.855204	2.883756	2.912594	2.9417196
Norfolk TS	115	2 West Cer	SIMCOE	M6	7.277	7.34977	7.423268	7.4975	7.572475	7.6482	7.724682	7.801929	7.879948	7.958748	8.038335	8.118719	8.199906	8.281905	8.364724	8.448371	8.532855	8.618183	8.704365	8.791409	8.879323	8.9681161
Oakville TS #2	230	2 West Cer	DUNDAS*	M45	17.074	17.24474	17.41719	17.59136	17.76727	17.94495	18.1244	18.30564	18.4887	18.67358	18.86032	19.04892	19.23941	19.4318	19.62612	19.82238	20.02061	20.22081	20.42302	20.62725	20.83352	21.04186
Oakville TS #2	230	2 West Cer	DUNDAS*	M46	19.648	19.84448	20.04292	20.24335	20.44579	20.65025	20.85675	21.06532	21.27597	21.48873	21.70362	21.92065	22.13986	22.36126	22.58487	22.81072	23.03883	23.26921	23.50191	23.73692	23.97429	24.214037
Oakville TS #2	230	2 West Cer	DUNDAS*	M47	11.649	11.76549	11.88314	12.00198	12.122	12.24322	12.36565	12.4893	12.6142	12.74034	12.86774	12.99642	13.12638	13.25765	13.39023	13.52413	13.65937	13.79596	13.93392	14.07326	14.21399	14.356134
Oakville TS #2	230	2 West Cer	DUNDAS*	M48	0.418	0.42218	0.426402	0.430666	0.434972	0.439322	0.443715	0.448153	0.452634	0.45716	0.461732	0.466349	0.471013	0.475723	0.48048	0.485285	0.490138	0.495039	0.49999	0.50499	0.510039	0.5151398
Orangeville TS	230	2 West Cer	ORANGEVILLE	M25	8.883	8.97183	9.061548	9.152164	9.243685	9.336122	9.429483	9.523778	9.619016	9.715206	9.812358	9.910482	10.00959	10.10968	10.21078	10.31289	10.41602	10.52018	10.62538	10.73163	10.83895	10.947338
Orangeville TS	230	2 West Cer	ORANGEVILLE	M26	9.569	9.66469	9.761337	9.85895	9.95754	10.05712	10.15769	10.25926	10.36186	10.46547	10.57013	10.67583	10.78259	10.89041	10.99932	11.10931	11.22041	11.33261	11.44594	11.56039	11.676	11.792758
Palermo TS	230	2 West Cer	DUNDAS*	M1	9.301	9.39401	9.48795	9.58283	9.678658	9.775444	9.873199	9.971931	10.07165	10.17237	10.27409	10.37683	10.4806	10.58541	10.69126	10.79817	10.90615	11.01522	11.12537	11.23662	11.34899	11.462477
Palermo TS	230	2 West Cer	DUNDAS*	M3	3.472	3.50672	3.541787	3.577205	3.612977	3.649107	3.685598	3.722454	3.759678	3.797275	3.835248	3.8736	3.912337	3.95146	3.990974	4.030884	4.071193	4.111905	4.153024	4.194554	4.2365	4.2788648
Port Colborne TS	115	2 West Cer	LINCOLN	M11	12.551	12.67651	12.80328	12.93131	13.06062	13.19123	13.32314	13.45637	13.59093	13.72684	13.86411	14.00275	14.14278	14.28421	14.42705	14.57132	14.71703	14.8642	15.01285	15.16298	15.31461	15.467751
Ramore TS	115	6 Northeas	KIRKLAND LAKE	M3	1.513	1.52813	1.543411	1.558845	1.574434	1.590178	1.60608	1.622141	1.638362	1.654746	1.671293	1.688006	1.704886	1.721935	1.739154	1.756546	1.774111	1.791853	1.809771	1.827869	1.846148	1.864609
Ramore TS	115	6 Northeas	KIRKLAND LAKE	M5	2.017	2.03717	2.057542	2.078117	2.098898	2.119887	2.141086	2.162497	2.184122	2.205963	2.228023	2.250303	2.272806	2.295534	2.318489	2.341674	2.365091	2.388742	2.412629	2.436756	2.461123	2.4857345
Richview TS	230	2 West Cer	ORANGEVILLE*	M4	9.912	10.01112	10.11123	10.21234	10.31447	10.41761	10.52179	10.62701	10.73328	10.84061	10.94901	11.0585	11.16909	11.28078	11.39359	11.50752	11.6226	11.73883	11.85621	11.97478	12.09452	12.215469
Richview TS	230	2 West Cer	ORANGEVILLE*	M47	11.451	11.56551	11.68117	11.79798	11.91596	12.03512	12.15547	12.27702	12.39979	12.52379	12.64903	12.77552	12.90327	13.03231	13.16263	13.29426	13.4272	13.56147	13.69708	13.83406	13.9724	14.11212
Richview TS	230	2 West Cer	ORANGEVILLE*	M5	4.095	4.13595	4.17731	4.219083	4.261273	4.303886	4.346925	4.390394	4.434298	4.478641	4.523428	4.568662	4.614348	4.660492	4.707097	4.754168	4.80171	4.849727	4.898224	4.947206	4.996678	5.046645
Richview TS	230	2 West Cer	ORANGEVILLE*	M7	2.974	3.00374	3.033777	3.064115	3.094756	3.125704	3.156961	3.188531	3.220416	3.25262	3.285146	3.317998	3.351178	3.384689	3.418536	3.452722	3.487249	3.522121	3.557343	3.592916	3.628845	3.6651336
Seaforth TS	230	1 West	CLINTON	M2	10.141	10.24241	10.34483	10.44828	10.55277	10.65829	10.76488	10.87252	10.98125	11.09106	11.20197	11.31399	11.42713	11.5414	11.65682	11.77339	11.89112	12.01003	12.13013	12.25143	12.37395	12.497687
Seaforth TS	230	1 West	CLINTON	M3	3.515	3.55015	3.585652	3.621508	3.657723	3.6943	3.731243	3.768556	3.806241	3.844304	3.882747	3.921574	3.96079	4.000398	4.040402	4.080806	4.121614	4.16283	4.204458	4.246503	4.288968	4.3318577
Seaforth TS	230	1 West	CLINTON	M4	6.178	6.23978	6.302178	6.3652	6.428852	6.49314	6.558071	6.623652	6.689889	6.756788	6.824355	6.892599	6.961525	7.03114	7.101452	7.172466	7.244191	7.316633	7.389799	7.463697	7.538334	7.6137174
Seaforth TS	230	1 West	CLINTON	M5	4.159	4.20059	4.242596	4.285022	4.327872	4.371151	4.414862	4.459011	4.503601	4.548637	4.594123	4.640065	4.686465	4.73333	4.780663	4.82847	4.876755	4.925522	4.974777	5.024525	5.07477	5.1255181
Sheppard TS	230	3A Central	BOWMANVILLE*	M2	9.346	9.43946	9.533855	9.629193	9.725485	9.82274	9.920967	10.02018	10.12038	10.22158	10.3238	10.42704	10.53131	10.63662	10.74299	10.85042	10.95892	11.06851	11.17919	11.29099	11.4039	11.517935
Sheppard TS	230	3A Central	BOWMANVILLE*	M4	7.469	7.54369	7.619127	7.695318	7.772271	7.849994	7.928494	8.007779	8.087857	8.168735	8.250423	8.332927	8.416256	8.500419	8.585423	8.671277	8.75799	8.84557	8.934025	9.023366	9.113599	9.2047354
St.Thomas TS	115	1 West	AYLMER	M10	10.596	10.70196	10.80898	10.91707	11.02624	11.1365	11.24787	11.36035	11.47395	11.58869	11.70458	11.82162	11.93984	12.05924	12.17983	12.30163	12.42464	12.54889	12.67438	12.80112	12.92913	13.058425
St.Thomas TS	115	1 West	AYLMER	M11	0.034	0.03434	0.034683	0.03503	0.035381	0.035734	0.036092	0.036453	0.036817	0.037185	0.037557	0.037933	0.038312	0.038695	0.039082	0.039473	0.039868	0.040266	0.040669	0.041076	0.041486	0.0419013
Stratford TS	230	1 West	BEACHVILLE	M1	4.475	4.51975	4.564948	4.610597	4.656703	4.70327	4.750303	4.797806	4.845784	4.894242	4.943184	4.992616	5.042542	5.092967	5.143897	5.195336	5.247289	5.299762	5.35276	5.406288	5.46035	5.5149539
Stratford TS	230	1 West	BEACHVILLE	M6	10.984	11.09384	11.20478	11.31683	11.42999	11.54429	11.65974	11.77633	11.8941	12.01304	12.13317	12.2545	12.37705	12.50082	12.62582	12.75208	12.8796	13.0084	13.13848	13.26987	13.40257	13.536593
Stratford TS	230	1 West	BEACHVILLE	M7	11	11.11	11.2211	11.33331	11.44664	11.56111	11.67672	11.79349	11.91142	12.03054	12.15084	12.27235	12.39508	12.51903	12.64422	12.77066	12.89837	13.02735	13.15762	13.2892	13.42209	13.556311
Strathroy TS	115	1 West	STRATHROY	M1	10.866	10.97466	11.08441	11.19525	11.3072	11.42028	11.53448	11.64982	11.76632	11.88398	12.00282	12.12285	12.24408	12.36652	12.49019	12.61509	12.74124	12.86865	12.99734	13.12731	13.25858	13.391171
Strathroy TS	115	1 West	STRATHROY	M3	11	11.11	11.2211	11.33331	11.44664	11.56111	11.67672	11.79349	11.91142	12.03054	12.15084	12.27235	12.39508	12.51903	12.64422	12.77066	12.89837	13.02735	13.15762	13.2892	13.42209	13.556311
Tillsonburg TS	115	1 West	AYLMER	M1	7.486	7.56086	7.636469	7.712833	7.789962	7.867861	7.94654	8.026005	8.106265	8.187328	8.269201	8.351893	8.435412	8.519766	8.604964	8.691014	8.777924	8.865703	8.95436	9.043904	9.134343	9.2256861
Tillsonburg TS	115	1 West	AYLMER	M10	6.588	6.65388	6.720419	6.787623	6.855499	6.924054	6.993295	7.063228	7.13386	7.205199	7.277251	7.350023	7.423523	7.497759	7.572736	7.648463	7.724948	7.802198	7.88022	7.959022	8.038612	8.1189981
Tillsonburg TS	115	1 West	AYLMER	M2	8.367	8.45067	8.535177	8.620528	8.706734	8.793801	8.881739	8.970556	9.060262	9.150865	9.242373	9.334797	9.428145	9.522426	9.617651	9.713827	9.810966	9.909075	10.00817	10.10825	10.20933	10.311423
Tillsonburg TS	115	1 West	AYLMER	M3	13.467	13.60167	13.73769	13.87506	14.01381	14.15395	14.29549	14.43845	14.58283	14.72866	14.87595	15.02471	15.17495	15.3267	15.47997	15.63477	15.79112	15.94903	16.10852	16.2696	16.4323	16.596622
Tillsonburg TS	115	1 West	AYLMER	M4	10.36	10.4636	10.56824	10.67392	10.78066	10.88846	10.99735	11.10732	11.2184	11.33058	11.44389	11.55832	11.67391	11.79065	11.90855	12.02764	12.14791	12.26939	12.39209	12.51601	12.64117	12.767581
Timmins TS	115	6 Northeas	TIMMINS	M10	8.302	8.38502	8.46887	8.553559	8.639094	8.725485	8.81274	8.900868	8.989876	9.079775	9.170573	9.262279	9.354901	9.44845	9.542935	9.638364	9.734748	9.832095	9.930416	10.02972	10.13002	10.231318
Timmins TS	115	6 Northeas	TIMMINS	M11	0.42	0.4242	0.428442	0.432726	0.437054	0.441424	0.445838	0.450297	0.4548	0.459348	0.463941	0.468581	0.473267	0.477999	0.482779	0.487607	0.492483	0.497408	0.502382	0.507406	0.51248	0.5176046
Timmins TS	115	6 Northeas	TIMMINS	M5	8.15	8.2315	8.313815	8.396953	8.480923	8.565732	8.651389	8.737903	8.825282	8.913535	9.00267	9.092697	9.183624	9.27546	9.368215	9.461897	9.556516	9.652081	9.748602	9.846088	9.944549	10.043994

Timmins TS	115	6 Northeas	TIMMINS	M6	5.244	5.29644	5.349404	5.402898	5.456927	5.511497	5.566612	5.622278	5.678501	5.735286	5.792638	5.850565	5.90907	5.968161	6.027843	6.088121	6.149002	6.210492	6.272597	6.335323	6.398677	6.4626633
Timmins TS	115	6 Northeas	TIMMINS	M7	12.79	12.9179	13.04708	13.17755	13.30933	13.44242	13.57684	13.71261	13.84974	13.98823	14.12812	14.2694	14.41209	14.55621	14.70178	14.84879	14.99728	15.14725	15.29873	15.45171	15.60623	15.762293
Timmins TS	115	6 Northeas	TIMMINS	M8	5.973	6.03273	6.093057	6.153988	6.215528	6.277683	6.34046	6.403864	6.467903	6.532582	6.597908	6.663887	6.730526	6.797831	6.865809	6.934468	7.003812	7.07385	7.144589	7.216035	7.288195	7.3610771
Timmins TS	115	6 Northeas	TIMMINS	M9	3.403	3.43703	3.4714	3.506114	3.541175	3.576587	3.612353	3.648477	3.684961	3.721811	3.759029	3.796619	3.834586	3.872931	3.911661	3.950777	3.990285	4.030188	4.07049	4.111195	4.152307	4.1938298
Wallaceburg TS	115	1 West	KENT	M1	5.042	5.09242	5.143344	5.194778	5.246725	5.299193	5.352185	5.405706	5.459764	5.514361	5.569505	5.6252	5.681452	5.738266	5.795649	5.853605	5.912142	5.971263	6.030976	6.091285	6.152198	6.2137202
Wallaceburg TS	115	1 West	KENT	M2	7.777	7.85477	7.933318	8.012651	8.092777	8.173705	8.255442	8.337997	8.421377	8.50559	8.590646	8.676553	8.763318	8.850951	8.939461	9.028856	9.119144	9.210336	9.302439	9.395463	9.489418	9.5843121
Wallaceburg TS	115	1 West	KENT	M3	3.476	3.51076	3.545868	3.581326	3.61714	3.653311	3.689844	3.726742	3.76401	3.80165	3.839667	3.878063	3.916844	3.956012	3.995572	4.035528	4.075883	4.116642	4.157809	4.199387	4.241381	4.2837944
Wallaceburg TS	115	1 West	KENT	M5	6.414	6.47814	6.542921	6.608351	6.674434	6.741178	6.80859	6.876676	6.945443	7.014897	7.085046	7.155897	7.227456	7.29973	7.372728	7.446455	7.520919	7.596129	7.67209	7.748811	7.826299	7.9045619
Wallaceburg TS	115	1 West	KENT	M6	5.203	5.25503	5.30758	5.360656	5.414263	5.468405	5.523089	5.57832	5.634103	5.690444	5.747349	5.804822	5.862871	5.921499	5.980714	6.040521	6.100927	6.161936	6.223555	6.285791	6.348649	6.4121353
Wanstead TS	115	1 West	LAMBTON	M1	9.706	9.80306	9.901091	10.0001	10.1001	10.2011	10.30311	10.40615	10.51021	10.61531	10.72146	10.82868	10.93696	11.04633	11.1568	11.26836	11.38105	11.49486	11.60981	11.72591	11.84316	11.961596
Wanstead TS	115	1 West	LAMBTON	M2	6.615	6.68115	6.747962	6.815441	6.883596	6.952431	7.021956	7.092175	7.163097	7.234728	7.307075	7.380146	7.453948	7.528487	7.603772	7.67981	7.756608	7.834174	7.912516	7.991641	8.071557	8.1522727
Wanstead TS	115	1 West	LAMBTON	M4	6.192	6.25392	6.316459	6.379624	6.44342	6.507854	6.572933	6.638662	6.705049	6.772099	6.83982	6.908218	6.977301	7.047074	7.117544	7.18872	7.260607	7.333213	7.406545	7.480611	7.555417	7.6309709
Warden TS	230	3A Central	NEWMARKET*	M21	6.195	6.25695	6.31952	6.382715	6.446542	6.511007	6.576117	6.641879	6.708297	6.77538	6.843134	6.911565	6.980681	7.050488	7.120993	7.192203	7.264125	7.336766	7.410134	7.484235	7.559077	7.6346681
Warden TS	230	3A Central	NEWMARKET*	M31	10.2	10.302	10.40502	10.50907	10.61416	10.7203	10.82751	10.93578	11.04514	11.15559	11.26715	11.37982	11.49362	11.60855	11.72464	11.84188	11.9603	12.07991	12.2007	12.32271	12.44594	12.570398
Warden TS	230	3A Central	NEWMARKET*	M32	14	14.14	14.2814	14.42421	14.56846	14.71414	14.86128	15.00989	15.15999	15.31159	15.46471	15.61936	15.77555	15.93331	16.09264	16.25357	16.4161	16.58026	16.74606	16.91353	17.08266	17.253487
Wonderland TS	230	1 West	STRATHROY	M2	0.155	0.15655	0.158116	0.159697	0.161294	0.162907	0.164536	0.166181	0.167843	0.169521	0.171216	0.172929	0.174658	0.176404	0.178169	0.17995	0.18175	0.183567	0.185403	0.187257	0.189129	0.1910208
Woodbridge TS	230	3A Central	NEWMARKET*	M1	7.701	7.77801	7.85579	7.934348	8.013691	8.093828	8.174767	8.256514	8.339079	8.42247	8.506695	8.591762	8.67768	8.764456	8.852101	8.940622	9.030028	9.120328	9.211532	9.303647	9.396683	9.4906503
Woodbridge TS	230	3A Central	NEWMARKET*	M3	8.215	8.29715	8.380122	8.463923	8.548562	8.634048	8.720388	8.807592	8.895668	8.984625	9.074471	9.165215	9.256868	9.349436	9.442931	9.53736	9.632734	9.729061	9.826352	9.924615	10.02386	10.1241
Woodbridge TS	230	3A Central	NEWMARKET*	M4	9.5	9.595	9.69095	9.78786	9.885738	9.984595	10.08444	10.18529	10.28714	10.39001	10.49391	10.59885	10.70484	10.81189	10.92001	11.02921	11.1395	11.25089	11.3634	11.47704	11.59181	11.707723
Woodstock TS	115	1 West	BEACHVILLE	M4	9.749	9.84649	9.944955	10.0444	10.14485	10.2463	10.34876	10.45225	10.55677	10.66234	10.76896	10.87665	10.98542	11.09527	11.20622	11.31829	11.43147	11.54578	11.66124	11.77785	11.89563	12.014589
Woodstock TS	115	1 West	BEACHVILLE	M6	10.128	10.22928	10.33157	10.43489	10.53924	10.64463	10.75108	10.85859	10.96717	11.07684	11.18761	11.29949	11.41248	11.52661	11.64187	11.75829	11.87588	11.99464	12.11458	12.23573	12.35808	12.481666
Woodstock TS	115	1 West	BEACHVILLE	M9	4.561	4.60661	4.652676	4.699203	4.746195	4.793657	4.841593	4.890009	4.938909	4.988299	5.038182	5.088563	5.139449	5.190843	5.242752	5.295179	5.348131	5.401613	5.455629	5.510185	5.565287	5.6209396
Alliston TS	230	2 West Cei	ALLISTON	M1	11.518	11.63318	11.74951	11.86701	11.98568	12.10553	12.22659	12.34885	12.47234	12.59707	12.72304	12.85027	12.97877	13.10856	13.23964	13.37204	13.50576	13.64082	13.77723	13.915	14.05415	14.19469
Alliston TS	230	2 West Cei	ALLISTON	M11	14.388	14.53188	14.6772	14.82397	14.97221	15.12193	15.27315	15.42588	15.58014	15.73594	15.8933	16.05224	16.21276	16.37489	16.53863	16.70402	16.87106	17.03977	17.21017	17.38227	17.55609	17.731655
Alliston TS	230	2 West Cei	ALLISTON	M12	16.692	16.85892	17.02751	17.19778	17.36976	17.54346	17.71889	17.89608	18.07504	18.25579	18.43835	18.62274	18.80896	18.99705	19.18702	19.37889	19.57268	19.76841	19.96609	20.16575	20.36741	20.571086
Alliston TS	230	2 West Cei	ALLISTON	M3	11.09	11.2009	11.31291	11.42604	11.5403	11.6557	11.77226	11.88998	12.00888	12.12897	12.25026	12.37276	12.49649	12.62145	12.74767	12.87515	13.0039	13.13394	13.26528	13.39793	13.53191	13.667227
Alliston TS	230	2 West Cei	ALLISTON	M4	13.507	13.64207	13.77849	13.91628	14.05544	14.19599	14.33795	14.48133	14.62615	14.77241	14.92013	15.06933	15.22003	15.37223	15.52595	15.68121	15.83802	15.9964	16.15636	16.31793	16.48111	16.645918
Alliston TS	230	2 West Cei	ALLISTON	M5	10.937	11.04637	11.15683	11.2684	11.38109	11.4949	11.60985	11.72594	11.8432	11.96164	12.08125	12.20206	12.32409	12.44733	12.5718	12.69752	12.82449	12.95274	13.08226	13.21309	13.34522	13.478671
Alliston TS	230	2 West Cei	ALLISTON	M6	9.651	9.74751	9.844985	9.943435	10.04287	10.1433	10.24473	10.34718	10.45065	10.55516	10.66071	10.76732	10.87499	10.98374	11.09358	11.20451	11.31656	11.42972	11.54402	11.65946	11.77605	11.893815
Almonte TS	230	4 East	PERTH	M25	8.577	8.66277	8.749398	8.836892	8.925261	9.014513	9.104658	9.195705	9.287662	9.380539	9.474344	9.569087	9.664778	9.761426	9.85904	9.957631	10.05721	10.15778	10.25936	10.36195	10.46557	10.570226
Almonte TS	230	4 East	PERTH	M26	4.984	5.03384	5.084178	5.13502	5.18637	5.238234	5.290616	5.343523	5.396958	5.450927	5.505437	5.560491	5.616096	5.672257	5.728979	5.786269	5.844132	5.902573	5.961599	6.021215	6.081427	6.1422414
Almonte TS	230	4 East	PERTH	M28	14.043	14.18343	14.32526	14.46852	14.6132	14.75933	14.90693	15.056	15.20656	15.35862	15.51221	15.66733	15.824	15.98224	16.14207	16.30349	16.46652	16.63119	16.7975	16.96547	17.13513	17.30648
Armitage TS	230	3A Central	NEWMARKET	M12	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Armitage TS	230	3A Central	NEWMARKET	M14	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Armitage TS	230	3A Central	NEWMARKET	M22	18.629	18.81529	19.00344	19.19348	19.38541	19.57927	19.77506	19.97281	20.17254	20.37426	20.57801	20.78379	20.99162	21.20154	21.41356	21.62769	21.84397	22.06241	22.28303	22.50586	22.73092	22.958229
Armitage TS	230	3A Central	NEWMARKET	M31	8.673	8.75973	8.847327	8.935801	9.025159	9.11541	9.206564	9.29863	9.391616	9.485532	9.580388	9.676192	9.772953	9.870683	9.96939	10.06908	10.16977	10.27147	10.37419	10.47793	10.58271	10.688535
Armitage TS	230	3A Central	NEWMARKET	M32	10.052	10.15252	10.25405	10.35659	10.46015	10.56475	10.6704	10.7771	10.88488	10.99372	11.10366	11.2147	11.32685	11.44011	11.55451	11.67006	11.78676	11.90463	12.02367	12.14391	12.26535	12.388004
Armitage TS	230	3A Central	NEWMARKET	M34	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Armitage TS	230	3A Central	NEWMARKET	M41	15.117	15.26817	15.42085	15.57506	15.73081	15.88812	16.047	16.20747	16.36954	16.53324	16.69857	16.86556	17.03421	17.20456	17.3766	17.55037	17.72587	17.90313	18.08216	18.26298	18.44561	18.630069
Armitage TS	230	3A Central	NEWMARKET	M42	19.509	19.70409	19.90113	20.10014	20.30114	20.50416	20.7092	20.91629	21.12545	21.33671	21.55007	21.76557	21.98323	22.20306	22.42509	22.64934	22.87584	23.1046	23.33564	23.569	23.80469	24.042734
Armitage TS	230	3A Central	NEWMARKET	M43	16.928	17.09728	17.26825	17.44094	17.61534	17.7915	17.96941	18.14911	18.3306	18.5139	18.69904	18.88603	19.07489	19.26564	19.4583	19.65288	19.84941	20.04791	20.24838	20.45087	20.65538	20.861931
Armitage TS	230	3A Central	NEWMARKET	M44	15.181	15.33281	15.48614	15.641	15.79741	15.95538	16.11494	16.27609	16.43885	16.60324	16.76927	16.93696	17.10633	17.27739	17.45017	17.62467	17.80092	17.97893	18.15871	18.3403	18.5237	18.708942
Arnprior TS	115	4 East	ARNPRIOR	M1	14.869	15.01769	15.16787	15.31955	15.47274	15.62747	15.78374	15.94158	16.101	16.26201	16.42463	16.58887	16.75476	16.92231	17.09153	17.26245	17.43507	17.60942	17.78552	17.96337	18.14301	18.324436
Arnprior TS	115	4 East	ARNPRIOR	M2	11.502	11.61702	11.73319	11.85052	11.96903	12.08872	12.2096	12.3317	12.45502	12.57957	12.70536	12.83242	12.96074	13.09035	13.22125	13.35346	13.487	13.62187	13.75809	13.89567	14.03463	14.174972
Barrie TS	115	5 Georgian	BARRIE	M3	5.549	5.60449	5.660535	5.71714	5.774312	5.832055	5.890375	5.949279	6.008772	6.06886	6.129548	6.190844	6.252752	6.31528	6.378432	6.442217	6.506639	6.571705	6.637422	6.703797	6.770835	6.8385429
Beaverton TS	230	3A Central	FENELON FALLS	M23	10.945	11.05445	11.16499	11.27664	11.38941	11.5033	11.61834	11.73452	11.85187	11.97039	12.09009	12.21099	12.3331	12.45643	12.581	12.70681	12.83387	12.96221	13.09183	13.22275	13.35498	13.48853
Beaverton TS	230	3A Central	FENELON FALLS	M24	7.818	7.89618	7.975142	8.054893	8.135442	8.216797	8.298965	8.381954	8.465774	8.550431	8.635936	8.722295	8.809518	8.897613	8.986589	9.076455	9.16722	9.258892	9.351481	9.444996	9.539446	9.6348402
Beaverton TS	230	3A Central	FENELON FALLS	M26	10.723	10.83023	10.93853	11.04792	11.1584	11.26998	11.38268	11.49651	11.61147	11.72759	11.84486	11.96331	12.08294	12.20377	12.32581	12.44907	12.57356	12.6993	12.82629	12.95455	13.0841	13.214939
Beaverton TS	230	3A Central	FENELON FALLS	M27	4.528	4.57328	4.619013	4.665203	4.711855	4.758974	4.806563	4.854629	4.903175	4.952207	5.001729	5.051746	5.102264	5.153286	5.204819	5.256867	5.309436	5.36253	5.416156	5.470317	5.525021	5.5802707
Beaverton TS	230	3A Central	FENELON FALLS	M29	8.839	8.92739	9.016664	9.106831	9.197899	9.289878	9.382777	9.476604	9.57137	9.667084	9.763755	9.861393	9.960006	10.05961	10.1602	10.2618	10.36442	10.46807	10.57275	10.67848	10.78526	10.893112
Beaverton TS	230	3A Central	FENELON FALLS	M30	8.231	8.31331	8.396443	8.480408	8.565212	8.650864	8.737372	8.824746	8.912994	9.002123	9.092145	9.183066	9.274897	9.367646	9.461322	9.555935	9.651495	9.74801	9.84549	9.943945	10.04338	10.143818
Belleville TS	230	3B East Ce	TRENTON	8M2	11.864	11.98264	12.10247	12.22349	12.34573	12.46918	12.59388	12.71981	12.84701	12.97548	13.10524	13.23629	13.36865	13.50234	13.63736	13.77374	13.91147	14.05059	14.19109	14.333	14.47633	14.621098
Belleville TS	230	3B East Ce	TRENTON	8M5	14.712	14.85912	15.00771	15.15779	15.30937	15.46246	15.61708	15.77326	15.93099	16.0903	16.2512	16.41371	16.57785	16.74363	16.91106	17.08018	17.25098	17.42349	17.59772	17.7737	17.95144	18.13095
Belleville TS	230	3B East Ce	TRENTON	8M6	12.349	12.47249	12.59721	12.72319	12.85042	12.97892	13.10871	13.2398	13.3722	13.50592	13.64098	13.77739	13.91516	14.05431	14.19486	14.33681	14.48017	14.62498	14.77123	14.91894	15.06813	15.218808
Belleville TS	230	3B East Ce	TRENTON	8M7	10.078	10.17878	10.28057	10.38337	10.48721	10.59208	10.698	10.80498	10.91303	11.02216	11.13238	11.24371	11.35614	11.4697	11.5844	11.70025	11.81725	11.93542	12.05477	12.17532	12.29708	12.420046
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M23	15.01	15.1601	15.3117	15.46482	15.61947	15.77566	15.93342	16.09275	16.25368	16.41622	16.58038	16.74618	16.91364	17.08278	17.25361	17.42614	17.60041	17.77641	17.95417	18.13372	18.31505	18.498203
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M24	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M45	30.385	30.68885	30.99574	31.3057	31.61875	31.93494	32.25429	32.57683	32.9026	33.23163	33.56394	33.89958	34.23858	34.58096	34.92677	35.27604	35.6288	35.98509	36.34494	36.70839	37.07547	37.446229
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M46	25.63	25.8863	26.14516	26.40661	26.67068	26.93739	27.20676	27.47883	27.75362	28.03115	28.31147	28.59458	28.88053	29.16933	29.46102	29.75563	30.05319	30.35372	30.65726	30.96383	31.27347	31.586205
Brockville TS	230	4 East	BROCKVILLE	B1R	18.601	18.78701	18.97488	19.16463	19.35628	19.54984	19.74534	19.94279	20.14222	20.34364	20.54708	20.75255	20.96007	21.16967	21.38137	21.59518	21.81114	22.02925	22.24954	22.47203	22.69675	22.923722
Brockville TS	230	4 East	BROCKVILLE	M1	11.42	11.5342	11.64954	11.76604	11.8837	12.00253	12.12256	12.24379	12.36622	12.48989	12.61478	12.74093	12.86834	12.99703	13.127	13.25827	13.39085	13.52476	13.66	13.7966	13.93457	14.073916
Brockville TS	230	4 East	BROCKVILLE	M2	9.749	9.84649	9.944955	10.0444	10.14485	10.2463	10.34876	10.45225	10.55677	10.66234	10.76896	10.87665	10.98542	11.09527	11.20622	11.31829	11.43147	11.54578	11.66124	11.77785	11.89563	12.014589
Brockville TS	230	4 East	BROCKVILLE	M3	16.894	17.06294	17.23357	17.40591	17.57996	17.75576	17.93332	18.11265	18.29378	18.47672	18.66149	18.8481	19.03658	19.22695	19.41922	19.61341	19.80954	20.00764	20.20772	20.40979	20.61389	20.820029
Brockville TS	230	4 East	BROCKVILLE	M4	11.914	12.03314	12.15347	12.27501	12.39776	12.52173	12.64695	12.77342	12.90115	13.03017	13.16047	13.29207	13.42499	13.55924	13.69484	13.83178	13.9701	14.1098	14.2509	14.39341	14.53734	14.682718
Brockville TS	230	4 East	BROCKVILLE	M5	9.671	9.76771	9.865387	9.964041	10.06368	10.16432	10.26596	10.36862	10.47231	10.57703	10.6828	10.78963	10.89752	11.0065	11.11657	11.22773	11.34001	11.45341	11.56794	11.68362	11.80046	11.918462
Brockville TS	230	4 East	BROCKVILLE	M6	8.935	9.02435	9.114594	9.205739	9.297797	9.390775	9.484683	9.579529	9.675325	9.772078	9.869799	9.968497	10.06818	10.16886	10.27055	10.37326	10.47699	10.58176	10.68758	10.79445	10.9024	11.011422
Brown Hill TS	230	3A Central	NEWMARKET	M1	10.957	11.06657	11.17724	11.28901	11.4019	11.51592	11.63108	11.74739	11.86486	11.98351	12.10334	12.22438	12.34662	12.47009	12.59479	12.72074	12.84794	12.97642	13.10619	13.23725	13.36962	13.503318

Brown Hill TS	230	3A Central	NEWMARKET	M11	8.642	8.72842	8.815704	8.903861	8.9929	9.082829	9.173657	9.265394	9.358048	9.451628	9.546144	9.641606	9.738022	9.835402	9.933756	10.03309	10.13342	10.23476	10.33711	10.44048	10.54488	10.650331
Brown Hill TS	230	3A Central	NEWMARKET	M12	7.048	7.11848	7.189665	7.261561	7.334177	7.407519	7.481594	7.55641	7.631974	7.708294	7.785377	7.863231	7.941863	8.021281	8.101494	8.182509	8.264334	8.346978	8.430447	8.514752	8.599899	8.6858984
Brown Hill TS	230	3A Central	NEWMARKET	M2	6.687	6.75387	6.821409	6.889623	6.958519	7.028104	7.098385	7.169369	7.241063	7.313473	7.386608	7.460474	7.535079	7.61043	7.686534	7.763399	7.841033	7.919444	7.998638	8.078625	8.159411	8.2410049
Brown Hill TS	230	3A Central	NEWMARKET	M3	8.214	8.29614	8.379101	8.462892	8.547521	8.632997	8.719327	8.80652	8.894585	8.983531	9.073366	9.1641	9.255741	9.348298	9.441781	9.536199	9.631561	9.727877	9.825155	9.923407	10.02264	10.122867
Cherrywood TS	500	3A Central	NEWMARKET*	M6	16.048	16.20848	16.37056	16.53427	16.69961	16.86661	17.03528	17.20563	17.37768	17.55146	17.72698	17.90425	18.08329	18.26412	18.44676	18.63123	18.81754	19.00572	19.19577	19.38773	19.58161	19.777426
Cherrywood TS	500	3A Central	NEWMARKET*	M7	15.638	15.79438	15.95232	16.11185	16.27297	16.4357	16.60005	16.76605	16.93371	17.10305	17.27408	17.44682	17.62129	17.7975	17.97548	18.15523	18.33678	18.52015	18.70535	18.89241	19.08133	19.272145
Cherrywood TS	500	3A Central	NEWMARKET*	M8	20.953	21.16253	21.37416	21.5879	21.80378	22.02181	22.24203	22.46445	22.6891	22.91599	23.14515	23.3766	23.61036	23.84647	24.08493	24.32578	24.56904	24.81473	25.06288	25.31351	25.56664	25.822308
Chesterville TS	115	4 East	WINCHESTER	M2	10.53	10.6353	10.74165	10.84907	10.95756	11.06714	11.17781	11.28959	11.40248	11.51651	11.63167	11.74799	11.86547	11.98412	12.10396	12.225	12.34725	12.47073	12.59543	12.72139	12.8486	12.977087
Chesterville TS	115	4 East	WINCHESTER	M4	13.981	14.12081	14.26202	14.40464	14.54868	14.69417	14.84111	14.98952	15.13942	15.29081	15.44372	15.59816	15.75414	15.91168	16.0708	16.23151	16.39382	16.55776	16.72334	16.89057	17.05948	17.230072
Clarabelle TS	230	6 Northeas	SUDBURY	M7	6.709	6.77609	6.843851	6.912289	6.981412	7.051226	7.121739	7.192956	7.264886	7.337534	7.41091	7.485019	7.559869	7.635468	7.711822	7.788941	7.86683	7.945498	8.024953	8.105203	8.186255	8.2681175
Clarabelle TS	230	6 Northeas	SUDBURY	M8	18.594	18.77994	18.96774	19.15742	19.34899	19.54248	19.73791	19.93528	20.13464	20.33598	20.53934	20.74474	20.95218	21.16171	21.37332	21.58706	21.80293	22.02096	22.24117	22.46358	22.68821	22.915096
Cobden TS	115	3B East Ce	COBDEN	M2	5.194	5.24594	5.298399	5.351383	5.404897	5.458946	5.513536	5.568671	5.624358	5.680601	5.737407	5.794781	5.852729	5.911256	5.970369	6.030073	6.090373	6.151277	6.21279	6.274918	6.337667	6.4010437
Cobden TS	115	3B East Ce	COBDEN	M6	10	10.1	10.201	10.30301	10.40604	10.5101	10.6152	10.72135	10.82857	10.93685	11.04622	11.15668	11.26825	11.38093	11.49474	11.60969	11.72579	11.84304	11.96147	12.08109	12.2019	12.323919
Crosby TS	230	4 East	PERTH	M1	6.502	6.56702	6.63269	6.699017	6.766007	6.833667	6.902004	6.971024	7.040734	7.111142	7.182253	7.254076	7.326616	7.399883	7.473881	7.54862	7.624106	7.700347	7.777351	7.855124	7.933676	8.0130124
Crosby TS	230	4 East	PERTH	M2	6.543	6.60843	6.674514	6.741259	6.808672	6.876759	6.945526	7.014982	7.085131	7.155983	7.227543	7.299818	7.372816	7.446544	7.52101	7.59622	7.672182	7.748904	7.826393	7.904657	7.983703	8.0635405
Crystal Falls TS	230	6 Northeas	NIPISSING	M1	3.785	3.82285	3.861079	3.899689	3.938686	3.978073	4.017854	4.058032	4.098613	4.139599	4.180995	4.222805	4.265033	4.307683	4.35076	4.394267	4.43821	4.482592	4.527418	4.572692	4.618419	4.6646035
Crystal Falls TS	230	6 Northeas	NIPISSING	M2	7.515	7.59015	7.666052	7.742712	7.820139	7.898341	7.977324	8.057097	8.137668	8.219045	8.301235	8.384248	8.46809	8.552771	8.638299	8.724682	8.811929	8.900048	8.989048	9.078939	9.169728	9.2614254
Dobbin TS	230	3A Central	PETERBOROUGI	M1	10	10.1	10.201	10.30301	10.40604	10.5101	10.6152	10.72135	10.82857	10.93685	11.04622	11.15668	11.26825	11.38093	11.49474	11.60969	11.72579	11.84304	11.96147	12.08109	12.2019	12.323919
Dobbin TS	230	3A Central	PETERBOROUGI	M2	12.812	12.94012	13.06952	13.20022	13.33222	13.46554	13.6002	13.7362	13.87356	14.0123	14.15242	14.29394	14.43688	14.58125	14.72706	14.87433	15.02308	15.17331	15.32504	15.47829	15.63307	15.789406
Dobbin TS	230	3A Central	PETERBOROUGI	M3	0.324	0.32724	0.330512	0.333818	0.337156	0.340527	0.343933	0.347372	0.350846	0.354354	0.357898	0.361477	0.365091	0.368742	0.37243	0.376154	0.379915	0.383715	0.387552	0.391427	0.395342	0.399295
Dobbin TS	230	3A Central	PETERBOROUGI	M4	17	17.17	17.3417	17.51512	17.69027	17.86717	18.04584	18.2263	18.40856	18.59265	18.77858	18.96636	19.15603	19.34759	19.54106	19.73647	19.93384	20.13318	20.33451	20.53785	20.74323	20.950663
Dobbin TS	230	3A Central	PETERBOROUGI	M5	9.707	9.80407	9.902111	10.00113	10.10114	10.20215	10.30418	10.40722	10.51129	10.6164	10.72257	10.82979	10.93809	11.04747	11.15795	11.26953	11.38222	11.49604	11.611	11.72711	11.84438	11.962829
Dobbin TS	230	3A Central	PETERBOROUGI	M6	11.537	11.65237	11.76889	11.88658	12.00545	12.1255	12.24676	12.36923	12.49292	12.61785	12.74403	12.87147	13.00018	13.13018	13.26148	13.3941	13.52804	13.66332	13.79995	13.93795	14.07733	14.218106
Dobbin TS	230	3A Central	PETERBOROUGI	M7	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Dobbin TS	230	3A Central	PETERBOROUGI	M8	17	17.17	17.3417	17.51512	17.69027	17.86717	18.04584	18.2263	18.40856	18.59265	18.77858	18.96636	19.15603	19.34759	19.54106	19.73647	19.93384	20.13318	20.33451	20.53785	20.74323	20.950663
Douglas Point TS	230	1 West	WALKERTON	M1	8.764	8.85164	8.940156	9.029558	9.119854	9.211052	9.303163	9.396194	9.490156	9.585058	9.680908	9.777717	9.875495	9.97425	10.07399	10.17473	10.27648	10.37924	10.48304	10.58787	10.69375	10.800683
Douglas Point TS	230	1 West	WALKERTON	M2	0.828	0.83628	0.844643	0.853089	0.86162	0.870236	0.878939	0.887728	0.896605	0.905571	0.914627	0.923773	0.933011	0.942341	0.951765	0.961282	0.970895	0.980604	0.99041	1.000314	1.010317	1.0204205
Douglas Point TS	230	1 West	WALKERTON	M3	0.748	0.75548	0.763035	0.770665	0.778372	0.786156	0.794017	0.801957	0.809977	0.818077	0.826257	0.83452	0.842865	0.851294	0.859807	0.868405	0.877089	0.88586	0.894718	0.903665	0.912702	0.9218292
Douglas Point TS	230	1 West	WALKERTON	M4	8.041	8.12141	8.202624	8.28465	8.367497	8.451172	8.535684	8.62104	8.707251	8.794323	8.882267	8.971089	9.0608	9.151408	9.242922	9.335351	9.428705	9.522992	9.618222	9.714404	9.811548	9.9096636
Douglas Point TS	230	1 West	WALKERTON	M8	8.603	8.68903	8.77592	8.86368	8.952316	9.041839	9.132258	9.22358	9.315816	9.408974	9.503064	9.598095	9.694076	9.791016	9.888927	9.987816	10.08769	10.18857	10.29046	10.39336	10.49729	10.602268
Dryden TS	230	7 Northwes	DRYDEN	M1	9.05	9.1405	9.231905	9.324224	9.417466	9.511641	9.606757	9.702825	9.799853	9.897852	9.99683	10.0968	10.19777	10.29974	10.40274	10.50677	10.61184	10.71796	10.82513	10.93339	11.04272	11.153147
Dryden TS	230	7 Northwes	DRYDEN	M3	2.14	2.1614	2.183014	2.204844	2.226893	2.249162	2.271653	2.29437	2.317313	2.340486	2.363891	2.38753	2.411406	2.43552	2.459875	2.484474	2.509318	2.534411	2.559756	2.585353	2.611207	2.6373188
Dymond TS	230	6 Northeas	NEW LISKEARD	M1	20.894	21.10294	21.31397	21.52711	21.74238	21.9598	22.1794	22.4012	22.62521	22.85146	23.07997	23.31077	23.54388	23.77932	24.01711	24.25729	24.49986	24.74486	24.99231	25.24223	25.49465	25.749597
Dymond TS	230	6 Northeas	NEW LISKEARD	M3	16.144	16.30544	16.46849	16.63318	16.79951	16.96751	17.13718	17.30855	17.48164	17.65646	17.83302	18.01135	18.19146	18.37338	18.55711	18.74268	18.93011	19.11941	19.3106	19.50371	19.69875	19.895735
Elliot Lake TS	115	6 Northeas	ALGOMA	M1	16.882	17.05082	17.22133	17.39354	17.56748	17.74315	17.92058	18.09979	18.28079	18.46359	18.64823	18.83471	19.02306	19.21329	19.40542	19.59948	19.79547	19.99343	20.19336	20.3953	20.59925	20.805241
Elliot Lake TS	115	6 Northeas	ALGOMA	M3	10.98	11.0898	11.2007	11.3127	11.42583	11.54009	11.65549	11.77205	11.88977	12.00866	12.12875	12.25004	12.37254	12.49626	12.62123	12.74744	12.87491	13.00366	13.1337	13.26504	13.39769	13.531664
Espanola TS	115	6 Northeas	ALGOMA	M1	4.032	4.07232	4.113043	4.154174	4.195715	4.237673	4.280049	4.32285	4.366078	4.409739	4.453836	4.498375	4.543359	4.588792	4.63468	4.681027	4.727837	4.775115	4.822867	4.871095	4.919806	4.9690043
Espanola TS	115	6 Northeas	ALGOMA	M2	6.617	6.68317	6.750002	6.817502	6.885677	6.954534	7.024079	7.09432	7.165263	7.236915	7.309285	7.382377	7.456201	7.530763	7.606071	7.682132	7.758953	7.836542	7.914908	7.994057	8.073997	8.1547375
Fergus TS	230	2 West Ce	GUELPH	M1	13.52	13.6552	13.79175	13.92967	14.06897	14.20966	14.35175	14.49527	14.64022	14.78662	14.93449	15.08384	15.23467	15.38702	15.54089	15.6963	15.85326	16.0118	16.17191	16.33363	16.49697	16.661939
Fergus TS	230	2 West Ce	GUELPH	M2	5.268	5.32068	5.373887	5.427626	5.481902	5.536721	5.592088	5.648009	5.704489	5.761534	5.819149	5.877341	5.936114	5.995475	6.05543	6.115984	6.177144	6.238916	6.301305	6.364318	6.427961	6.4922407
Fergus TS	230	2 West Ce	GUELPH	M3	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Fergus TS	230	2 West Ce	GUELPH	M4	18.703	18.89003	19.07893	19.26972	19.46242	19.65704	19.85361	20.05215	20.25267	20.4552	20.65975	20.86635	21.07501	21.28576	21.49862	21.7136	21.93074	22.15005	22.37155	22.59526	22.82121	23.049426
Fergus TS	230	2 West Ce	GUELPH	M7	19.186	19.37786	19.57164	19.76735	19.96503	20.16468	20.36633	20.56999	20.77569	20.98345	21.19328	21.40521	21.61927	21.83546	22.05381	22.27435	22.49709	22.72206	22.94929	23.17878	23.41057	23.644672
Fergus TS	230	2 West Ce	GUELPH	M8	5.884	5.94284	6.002268	6.062291	6.122914	6.184143	6.245985	6.308444	6.371529	6.435244	6.499597	6.564593	6.630238	6.696541	6.763506	6.831141	6.899453	6.968447	7.038132	7.108513	7.179598	7.2513942
Fort Frances TS	230	7 Northwes	FORT FRANCES	M1	9.104	9.19504	9.28699	9.37986	9.473659	9.568395	9.664079	9.76072	9.858327	9.956911	10.05648	10.15704	10.25862	10.3612	10.46481	10.56946	10.67516	10.78191	10.88973	10.99862	11.10861	11.219696
Frontenac TS	115	3B East Ce	KINGSTON	M1	15.707	15.86407	16.02271	16.18294	16.34477	16.50821	16.6733	16.84003	17.00843	17.17851	17.3503	17.5238	17.69904	17.87603	18.05479	18.23534	18.41769	18.60187	18.78789	18.97577	19.16552	19.35718
Frontenac TS	115	3B East Ce	KINGSTON	M3	14.129	14.27029	14.41299	14.55712	14.70269	14.84972	14.99822	15.1482	15.29968	15.45268	15.60721	15.76328	15.92091	16.08012	16.24092	16.40333	16.56736	16.73304	16.90037	17.06937	17.24007	17.412466
Frontenac TS	115	3B East Ce	KINGSTON	M8	13.562	13.69762	13.8346	13.97294	14.11267	14.2538	14.39634	14.5403	14.6857	14.83256	14.98089	15.13069	15.282	15.43482	15.58917	15.74506	15.90251	16.06154	16.22215	16.38437	16.54822	16.713699
Gardiner TS	230	3B East Ce	KINGSTON	33M10	9.648	9.74448	9.841925	9.940344	10.03975	10.14014	10.24155	10.34396	10.4474	10.55188	10.65739	10.76397	10.87161	10.98032	11.09013	11.20103	11.31304	11.42617	11.54043	11.65584	11.77239	11.890117
Gardiner TS	230	3B East Ce	KINGSTON	33M11	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Gardiner TS	230	3B East Ce	KINGSTON	33M12	14.264	14.40664	14.55071	14.69621	14.84318	14.99161	15.14152	15.29294	15.44587	15.60033	15.75633	15.91389	16.07303	16.23376	16.3961	16.56006	16.72566	16.89292	17.06185	17.23247	17.40479	17.578839
Gardiner TS	230	3B East Ce	KINGSTON	33M13	13.4	13.534	13.66934	13.80603	13.94409	14.08353	14.22437	14.36661	14.51028	14.65538	14.80194	14.94996	15.09946	15.25045	15.40295	15.55698	15.71255	15.86968	16.02838	16.18866	16.35055	16.514052
Gardiner TS	230	3B East Ce	KINGSTON	33M14	17.365	17.53865	17.71404	17.89118	18.07009	18.25079	18.4333	18.61763	18.80381	18.99184	19.18176	19.37358	19.56732	19.76299	19.96062	20.16023	20.36183	20.56545	20.7711	20.97881	21.1886	21.400486
Gardiner TS	230	3B East Ce	KINGSTON	33M15	12.863	12.99163	13.12155	13.25276	13.38529	13.51914	13.65433	13.79088	13.92879	14.06807	14.20875	14.35084	14.49435	14.63929	14.78569	14.93354	15.08288	15.23371	15.38604	15.53991	15.6953	15.852258
Gardiner TS	230	3B East Ce	KINGSTON	33M3	12.328	12.45128	12.57579	12.70155	12.82857	12.95685	13.08642	13.21728	13.34946	13.48295	13.61778	13.75396	13.8915	14.03041	14.17072	14.31243	14.45555	14.60011	14.74611	14.89357	15.0425	15.192928
Gardiner TS	230	3B East Ce	KINGSTON	33M7	21.545	21.76045	21.97805	22.19784	22.41981	22.64401	22.87045	23.09916	23.33015	23.56345	23.79908	24.03707	24.27745	24.52022	24.76542	25.01308	25.26321	25.51584	25.771	26.02871	26.28899	26.551884
Gardiner TS	230	3B East Ce	KINGSTON	33M9	19.617	19.81317	20.0113	20.21141	20.41353	20.61766	20.82384	21.03208	21.2424	21.45482	21.66937	21.88607	22.10493	22.32598	22.54924	22.77473	23.00248	23.2325	23.46483	23.69947	23.93647	24.175833
Hanover TS	230	1 West	WALKERTON	H1E	13.119	13.25019	13.38269	13.51652	13.65168	13.7882	13.92608	14.06534	14.206	14.34806	14.49154	14.63645	14.78282	14.93065	15.07995	15.23075	15.38306	15.53689	15.69226	15.84918	16.00767	16.16775
Hanover TS	230	1 West	WALKERTON	M1	13.312	13.44512	13.57957	13.71537	13.85252	13.99105	14.13096	14.27227	14.41499	14.55914	14.70473	14.85178	15.00029	15.1503	15.3018	15.45482	15.60937	15.76546	15.92312	16.08235	16.24317	16.405602
Hanover TS	230	1 West	WALKERTON	M2	12.733	12.86033	12.98893	13.11882	13.25001	13.38251	13.51634	13.6515	13.78801	13.92589	14.06515	14.20581	14.34786	14.49134	14.63626	14.78262	14.93044	15.07975	15.23055	15.38285	15.53668	15.692047
Hanover TS	230	1 West	WALKERTON	M3	7.676	7.75276	7.830288	7.90859	7.987676	8.067553	8.148229	8.229711	8.312008	8.395128	8.479079	8.56387	8.649509	8.736004	8.823364	8.911598	9.000714	9.090721	9.181628	9.273444	9.366179	9.4598405
Hanover TS	230	1 West	WALKERTON	M4	9.561	9.65661	9.753176	9.850708	9.949215	10.04871	10.14919	10.25069	10.35319	10.45672	10.56129	10.66691	10.77357	10.88131	10.99012	11.10002	11.21102	11.32313	11.43637	11.55073	11.66624	11.782899
Hanover TS	230	1 West	WALKERTON	M5	15.841	15.99941	16.1594	16.321	16.48421	16.64905	16.81554	16.9837	17.15353	17.32507	17.49832	17.6733	17.85004	18.02854	18.20882	18.39091	18.57482	18.76057	18.94817	19.13765	19.32903	19.522321
Havelock TS	230	3B East Ce	TWEED	M1	8.786	8.87386	8.962599	9.052225	9.142747	9.234174	9.326516	9.419781	9.513979	9.609119	9.70521	9.802262	9.900285	9.999288	10.09928	10.20027	10.30228	10.4053	10.50935	10.61445	10.72059	10.827796
Havelock TS	230	3B East Ce	TWEED	M2	13.44	13.5744	13.71014	13.84725	13.98572	14.12558	14.26683	14.4095	14.55359	14.69913	14.84612	14.99458	15.14453	15.29597	15.44893	15.60342	15.75946	15.91705	16.07622	16.23698	16.39935	16.563348
Havelock TS	230	3B East Ce	TWEED	M3	4.123	4.16423	4.205872	4.247931	4.29041	4.333314	4.376648	4.420414	4.464618	4.509264	4.554357	4.599901	4.6459	4.692359	4.739282	4.786675	4.834542	4.882887	4.931716	4.981033	5.030844	5.081152

Havelock TS	230	3B East Ce	TWEED	M4	5.529	5.58429	5.640133	5.696534	5.7535	5.811035	5.869145	5.927836	5.987115	6.046986	6.107456	6.16853	6.230216	6.292518	6.355443	6.418997	6.483187	6.548019	6.613499	6.679634	6.746431	6.813895
Havelock TS	230	3B East Ce	TWEED	M6	11.451	11.56551	11.68117	11.79798	11.91596	12.03512	12.15547	12.27702	12.39979	12.52379	12.64903	12.77552	12.90327	13.03231	13.16263	13.29426	13.4272	13.56147	13.69708	13.83406	13.9724	14.11212
Hawthorne TS	500	4 East	WINCHESTER	M1	12.95	13.0795	13.2103	13.3424	13.47582	13.61058	13.74669	13.88415	14.02299	14.16322	14.30486	14.44791	14.59238	14.73831	14.88569	15.03455	15.18489	15.33674	15.49011	15.64501	15.80146	15.959476
Hawthorne TS	500	4 East	WINCHESTER	M2	25.57	25.8257	26.08396	26.3448	26.60824	26.87433	27.14307	27.4145	27.68865	27.96553	28.24519	28.52764	28.81292	29.10105	29.39206	29.68598	29.98284	30.28266	30.58549	30.89135	31.20026	31.512262
Kirkland Lake TS	115	6 Northeas	KIRKLAND LAKE	G3K	5.226	5.27826	5.331043	5.384353	5.438197	5.492579	5.547504	5.602979	5.659009	5.715599	5.772755	5.830483	5.888788	5.947675	6.007152	6.067224	6.127896	6.189175	6.251067	6.313577	6.376713	6.4404803
Kirkland Lake TS	115	6 Northeas	KIRKLAND LAKE	M61	7.567	7.64267	7.719097	7.796288	7.874251	7.952993	8.032523	8.112848	8.193977	8.275916	8.358676	8.442262	8.526685	8.611952	8.698071	8.785052	8.872903	8.961632	9.051248	9.14176	9.233178	9.3255098
Kirkland Lake TS	115	6 Northeas	KIRKLAND LAKE	M62	3.045	3.07545	3.106205	3.137267	3.168639	3.200326	3.232329	3.264652	3.297299	3.330272	3.363574	3.39721	3.431182	3.465494	3.500149	3.53515	3.570502	3.606207	3.642269	3.678692	3.715479	3.7526335
Kleinburg TS	230	3A Central	NEWMARKET	M23	16.723	16.89023	17.05913	17.22972	17.40202	17.57604	17.7518	17.92932	18.10861	18.2897	18.4726	18.65732	18.84389	19.03233	19.22266	19.41488	19.60903	19.80512	20.00317	20.20321	20.40524	20.60929
Kleinburg TS	230	3A Central	NEWMARKET	M24	17.044	17.21444	17.38658	17.56045	17.73605	17.91342	18.09255	18.27347	18.45621	18.64077	18.82718	19.01545	19.20561	19.39766	19.59164	19.78755	19.98543	20.18528	20.38714	20.59101	20.79692	21.004888
Kleinburg TS	230	3A Central	NEWMARKET	M25	22	22.22	22.4422	22.66662	22.89329	23.12222	23.35344	23.58698	23.82285	24.06108	24.30169	24.5447	24.79015	25.03805	25.28843	25.54132	25.79673	26.0547	26.31524	26.5784	26.84418	27.112623
Kleinburg TS	230	3A Central	NEWMARKET	M26	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Larchwood TS	115	6 Northeas	SUDBURY	M3	2.412	2.43612	2.460481	2.485086	2.509937	2.535036	2.560387	2.58599	2.61185	2.637969	2.664349	2.690992	2.717902	2.745081	2.772532	2.800257	2.82826	2.856542	2.885108	2.913959	2.943098	2.9725294
Larchwood TS	115	6 Northeas	SUDBURY	M4	13.959	14.09859	14.23958	14.38197	14.52579	14.67105	14.81776	14.96594	15.1156	15.26675	15.41942	15.57361	15.72935	15.88664	16.04551	16.20597	16.36803	16.53171	16.69702	16.86399	17.03263	17.202959
Lindsay TS	230	3A Central	FENELON FALLS	M3	4.408	4.45208	4.496601	4.541567	4.586982	4.632852	4.679181	4.725973	4.773232	4.820965	4.869174	4.917866	4.967045	5.016715	5.066882	5.117551	5.168727	5.220414	5.272618	5.325344	5.378598	5.4323837
Lindsay TS	230	3A Central	FENELON FALLS	M4	7.065	7.13565	7.207007	7.279077	7.351867	7.425386	7.49964	7.574636	7.650383	7.726886	7.804155	7.882197	7.961019	8.040629	8.121035	8.202246	8.284268	8.367111	8.450782	8.53529	8.620643	8.7068491
Lindsay TS	230	3A Central	FENELON FALLS	M5	9.831	9.92931	10.0286	10.12889	10.23018	10.33248	10.4358	10.54016	10.64556	10.75202	10.85954	10.96814	11.07782	11.1886	11.30048	11.41349	11.52762	11.6429	11.75933	11.87692	11.99569	12.115645
Lindsay TS	230	3A Central	FENELON FALLS	M6	16.95	17.1195	17.2907	17.4636	17.63824	17.81462	17.99277	18.17269	18.35442	18.53797	18.72335	18.91058	19.09968	19.29068	19.48359	19.67842	19.87521	20.07396	20.2747	20.47745	20.68222	20.889043
Lindsay TS	230	3A Central	FENELON FALLS	M7	6.585	6.65085	6.717359	6.784532	6.852377	6.920901	6.99011	7.060011	7.130611	7.201918	7.273937	7.346676	7.420143	7.494344	7.569288	7.644981	7.72143	7.798645	7.876631	7.955397	8.034951	8.1153009
Lindsay TS	230	3A Central	FENELON FALLS	M8	9.544	9.63944	9.735834	9.833193	9.931525	10.03084	10.13115	10.23246	10.33478	10.43813	10.54251	10.64794	10.75442	10.86196	10.97058	11.08029	11.19109	11.303	11.41603	11.53019	11.64549	11.761949
Longueuil TS	230	4 East	VANKLEEK HILL	M23	7.327	7.40027	7.474273	7.549015	7.624506	7.700751	7.777758	7.855536	7.934091	8.013432	8.093566	8.174502	8.256247	8.338809	8.422198	8.50642	8.591484	8.677399	8.764173	8.851814	8.940332	9.0297357
Longueuil TS	230	4 East	VANKLEEK HILL	M24	15.397	15.55097	15.70648	15.86354	16.02218	16.1824	16.34423	16.50767	16.67274	16.83947	17.00787	17.17795	17.34972	17.52322	17.69845	17.87544	18.05419	18.23474	18.41708	18.60125	18.78727	18.975139
Longueuil TS	230	4 East	VANKLEEK HILL	M25	7.572	7.64772	7.724197	7.801439	7.879454	7.958248	8.037831	8.118209	8.199391	8.281385	8.364199	8.447841	8.532319	8.617642	8.703819	8.790857	8.878765	8.967553	9.057229	9.147801	9.239279	9.3316718
Longueuil TS	230	4 East	VANKLEEK HILL	M26	5.542	5.59742	5.653394	5.709928	5.767027	5.824698	5.882945	5.941774	6.001192	6.061204	6.121816	6.183034	6.244864	6.307313	6.370386	6.43409	6.498431	6.563415	6.629049	6.69534	6.762293	6.8299161
Martindale TS	230	6 Northeas	SUDBURY	M5	10.232	10.33432	10.43766	10.54204	10.64746	10.75393	10.86147	10.97009	11.07979	11.19059	11.30249	11.41552	11.52967	11.64497	11.76142	11.87903	11.99782	12.1178	12.23898	12.36137	12.48498	12.609834
Martindale TS	230	6 Northeas	SUDBURY	M6	13.946	14.08546	14.22631	14.36858	14.51226	14.65739	14.80396	14.952	15.10152	15.25253	15.40506	15.55911	15.7147	15.87185	16.03057	16.19087	16.35278	16.51631	16.68147	16.84829	17.01677	17.186938
Martindale TS	230	6 Northeas	SUDBURY	M7	7.671	7.74771	7.825187	7.903439	7.982473	8.062298	8.142921	8.22435	8.306594	8.38966	8.473556	8.558292	8.643875	8.730314	8.817617	8.905793	8.994851	9.084799	9.175647	9.267404	9.360078	9.4536786
Meaford TS	115	5 Georgian	OWEN SOUND	M1	6.406	6.47006	6.534761	6.600108	6.666109	6.73277	6.800098	6.868099	6.93678	7.006148	7.076209	7.146971	7.218441	7.290626	7.363532	7.437167	7.511539	7.586654	7.662521	7.739146	7.816537	7.8947028
Meaford TS	115	5 Georgian	OWEN SOUND	M2	14.472	14.61672	14.76289	14.91052	15.05962	15.21022	15.36232	15.51594	15.6711	15.82781	15.98609	16.14595	16.30741	16.47049	16.63519	16.80154	16.96956	17.13925	17.31065	17.48375	17.65859	17.835176
Midhurst TS	230	5 Georgian	BARRIE	M10	19.294	19.48694	19.68181	19.87863	20.07741	20.27819	20.48097	20.68578	20.89264	21.10156	21.31258	21.52571	21.74096	21.95837	22.17796	22.39974	22.62373	22.84997	23.07847	23.30925	23.54235	23.77777
Midhurst TS	230	5 Georgian	BARRIE	M3	10.22	10.3222	10.42542	10.52968	10.63497	10.74132	10.84874	10.95722	11.0668	11.17746	11.28924	11.40213	11.51615	11.63131	11.74763	11.8651	11.98375	12.10359	12.22463	12.34687	12.47034	12.595046
Midhurst TS	230	5 Georgian	BARRIE	M4	12.435	12.55935	12.68494	12.81179	12.93991	13.06931	13.2	13.332	13.46532	13.59998	13.73598	13.87334	14.01207	14.15219	14.29371	14.43665	14.58102	14.72683	14.87409	15.02283	15.17306	15.324794
Midhurst TS	230	5 Georgian	BARRIE	M5	17.688	17.86488	18.04353	18.22396	18.4062	18.59027	18.77617	18.96393	19.15357	19.34511	19.53856	19.73394	19.93128	20.13059	20.3319	20.53522	20.74057	20.94798	21.15746	21.36903	21.58272	21.798549
Midhurst TS	230	5 Georgian	BARRIE	M6	14.152	14.29352	14.43646	14.58082	14.72663	14.87389	15.02263	15.17286	15.32459	15.47783	15.63261	15.78894	15.94683	16.1063	16.26736	16.43003	16.59433	16.76028	16.92788	17.09716	17.26813	17.440811
Midhurst TS	230	5 Georgian	BARRIE	M7	23.047	23.27747	23.51024	23.74535	23.9828	24.22263	24.46485	24.7095	24.9566	25.20616	25.45823	25.71281	25.96994	26.22964	26.49193	26.75685	27.02442	27.29466	27.56761	27.84329	28.12172	28.402937
Midhurst TS	230	5 Georgian	BARRIE	M8	17.85	18.0285	18.20879	18.39087	18.57478	18.76053	18.94813	19.13762	19.32899	19.52228	19.7175	19.91468	20.11383	20.31497	20.51811	20.7233	20.93053	21.13983	21.35123	21.56474	21.78039	21.998196
Midhurst TS	230	5 Georgian	BARRIE	M9	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Minden TS	230	3A Central	MINDEN	M1	10.771	10.87871	10.9875	11.09737	11.20835	11.32043	11.43363	11.54797	11.66345	11.78008	11.89788	12.01686	12.13703	12.2584	12.38099	12.5048	12.62984	12.75614	12.8837	13.01254	13.14267	13.274094
Minden TS	230	3A Central	MINDEN	M2	9.42	9.5142	9.609342	9.705435	9.80249	9.900515	9.99952	10.09952	10.20051	10.30252	10.40554	10.5096	10.61469	10.72084	10.82805	10.93633	11.04569	11.15615	11.26771	11.38039	11.49419	11.609132
Minden TS	230	3A Central	MINDEN	M3	11.792	11.90992	12.02902	12.14931	12.2708	12.39351	12.51745	12.64262	12.76905	12.89674	13.0257	13.15596	13.28752	13.4204	13.5546	13.69015	13.82705	13.96532	14.10497	14.24602	14.38848	14.532366
Morrisburg TS	115	4 East	WINCHESTER	M23	17.243	17.41543	17.58958	17.76548	17.94313	18.12257	18.30379	18.48683	18.6717	18.85842	19.047	19.23747	19.42984	19.62414	19.82038	20.01859	20.21877	20.42096	20.62517	20.83142	21.03974	21.250134
Morrisburg TS	115	4 East	WINCHESTER	M25	10.033	10.13333	10.23466	10.33701	10.44038	10.54478	10.65023	10.75673	10.8643	10.97294	11.08267	11.1935	11.30544	11.41849	11.53267	11.648	11.76448	11.88213	12.00095	12.12096	12.24217	12.364588
Morrisburg TS	115	4 East	WINCHESTER	M26	16.42	16.5842	16.75004	16.91754	17.08672	17.25759	17.43016	17.60446	17.78051	17.95831	18.1379	18.31927	18.50247	18.68749	18.87437	19.06311	19.25374	19.44628	19.64074	19.83715	20.03552	20.235876
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M1	14.376	14.51976	14.66496	14.81161	14.95972	15.10932	15.26041	15.41302	15.56715	15.72282	15.88005	16.03885	16.19924	16.36123	16.52484	16.69009	16.85699	17.02556	17.19582	17.36777	17.54145	17.716867
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M10	6.685	6.75185	6.819369	6.887562	6.956438	7.026002	7.096262	7.167225	7.238897	7.311286	7.384399	7.458243	7.532825	7.608154	7.684235	7.761077	7.838688	7.917075	7.996246	8.076208	8.15697	8.2385401
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M2	19.797	19.99497	20.19492	20.39687	20.60084	20.80685	21.01491	21.22506	21.43731	21.65169	21.8682	22.08689	22.30776	22.53083	22.75614	22.9837	23.21354	23.44567	23.68013	23.91693	24.1561	24.397663
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M3	11.108	11.21908	11.33127	11.44458	11.55903	11.67462	11.79137	11.90928	12.02837	12.14866	12.27014	12.39284	12.51677	12.64194	12.76836	12.89604	13.025	13.15525	13.28681	13.41967	13.55387	13.68941
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M4	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M7	13.041	13.17141	13.30312	13.43616	13.57052	13.70622	13.84328	13.98172	14.12153	14.26275	14.40538	14.54943	14.69493	14.84187	14.99029	15.1402	15.2916	15.44451	15.59896	15.75495	15.9125	16.071623
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M8	16.843	17.01143	17.18154	17.35336	17.52689	17.70216	17.87918	18.05798	18.23856	18.42094	18.60515	18.7912	18.97911	19.16891	19.36059	19.5542	19.74974	19.94724	20.14671	20.34818	20.55166	20.757177
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M9	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Napanee TS	230	3B East Ce	PICTON	M1	28.308	28.59108	28.87699	29.16576	29.45742	29.75199	30.04951	30.35001	30.65351	30.96004	31.26964	31.58234	31.89816	32.21714	32.53932	32.86471	33.19336	33.52529	33.86054	34.19915	34.54114	34.886551
Napanee TS	230	3B East Ce	PICTON	M2	28.646	28.93246	29.22178	29.514	29.80914	30.10723	30.40831	30.71239	31.01951	31.32971	31.64301	31.95944	32.27903	32.60182	32.92784	33.25712	33.58969	33.92558	34.26484	34.60749	34.95356	35.3031
Napanee TS	230	3B East Ce	PICTON	M3	14.928	15.07728	15.22805	15.38033	15.53414	15.68948	15.84637	16.00484	16.16488	16.32653	16.4898	16.6547	16.82124	16.98946	17.15935	17.33094	17.50425	17.6793	17.85609	18.03465	18.215	18.397147
Napanee TS	230	3B East Ce	PICTON	M4	14.236	14.37836	14.52214	14.66737	14.81404	14.96218	15.1118	15.26292	15.41555	15.5697	15.7254	15.88265	16.04148	16.2019	16.36391	16.52755	16.69283	16.85976	17.02836	17.19864	17.37063	17.544332
Orangeville TS	230	2 West Cer	ORANGEVILLE	M1	9.166	9.25766	9.350237	9.443739	9.538176	9.633558	9.729894	9.827193	9.925465	10.02472	10.12497	10.22622	10.32848	10.43176	10.53608	10.64144	10.74786	10.85533	10.96389	11.07353	11.18426	11.296105
Orangeville TS	230	2 West Cer	ORANGEVILLE	M2	4.793	4.84093	4.889339	4.938233	4.987615	5.037491	5.087866	5.138745	5.190132	5.242034	5.294454	5.347398	5.400872	5.454881	5.50943	5.564524	5.620169	5.676371	5.733135	5.790466	5.848371	5.9068546
Orangeville TS	230	2 West Cer	ORANGEVILLE	M3	10.285	10.38785	10.49173	10.59665	10.70261	10.80964	10.91773	11.02691	11.13718	11.24855	11.36104	11.47465	11.5894	11.70529	11.82234	11.94057	12.05997	12.18057	12.30238	12.4254	12.54965	12.675151
Orangeville TS	230	2 West Cer	ORANGEVILLE	M4	12.064	12.18464	12.30649	12.42955	12.55385	12.67939	12.80618	12.93424	13.06358	13.19422	13.32616	13.45942	13.59402	13.72996	13.86726	14.00593	14.14599	14.28745	14.43032	14.57463	14.72037	14.867576
Orangeville TS	230	2 West Cer	ORANGEVILLE	M45	9.526	9.62126	9.717473	9.814647	9.912794	10.01192	10.11204	10.21316	10.31529	10.41845	10.52263	10.62786	10.73414	10.84148	10.94989	11.05939	11.16998	11.28168	11.3945	11.50845	11.62353	11.739766
Orangeville TS	230	2 West Cer	ORANGEVILLE	M46	1.411	1.42511	1.439361	1.453755	1.468292	1.482975	1.497805	1.512783	1.527911	1.54319	1.558622	1.574208	1.58995	1.60585	1.621908	1.638127	1.654508	1.671054	1.687764	1.704642	1.721688	1.738905
Orangeville TS	230	2 West Cer	ORANGEVILLE	M5	15.103	15.25403	15.40657	15.56064	15.71624	15.8734	16.03214	16.19246	16.35438	16.51793	16.68311	16.84994	17.01844	17.18862	17.36051	17.53411	17.70946	17.88655	18.06542	18.24607	18.42853	18.612815
Orangeville TS	230	2 West Cer	ORANGEVILLE	M6	7.858	7.93658	8.015946	8.096105	8.177066	8.258837	8.341425	8.42484	8.509088	8.594179	8.680121	8.766922	8.854591	8.943137	9.032568	9.122894	9.214123	9.306264	9.399327	9.49332	9.588253	9.6841359
Orillia TS	230	5 Georgian	ORILLIA	M1	11.856	11.97456	12.09431	12.21525	12.3374	12.46078	12.58538	12.71124	12.83835	12.96673	13.0964	13.22736	13.35964	13.49323	13.62817	13.76445	13.90209	14.04111	14.18152	14.32334	14.46657	14.611239
Orillia TS	230	5 Georgian	ORILLIA	M2	14.874	15.02274	15.17297	15.3247	15.47794	15.63272	15.78905	15.94694	16.10641	16.26747	16.43015	16.59445	16.7604	16.928	17.09728	17.26825	17.44093	17.61534	17.7915	17.96941	18.14911	18.330598
Orillia TS	230	5 Georgian	ORILLIA	M3	5.818	5.87618	5.934942	5.994291	6.054234	6.114776	6.175924	6.237683	6.30006	6.363061	6.426692	6.490958	6.555868	6.621427	6.687641	6.754517	6.822063	6.890283	6.959186	7.028778	7.099066	7.1700563
Orillia TS	230	5 Georgian	ORILLIA	M4	14.874	15.02274	15.17297	15.3247	15.47794	15.63272	15.78905	15.94694	16.10641	16.26747	16.43015	16.59445	16.7604	16.928	17.09728	17.26825	17.44093	17.61534	17.7915	17.96941	18.14911	18.330598
Orillia TS	230	5 Georgian	ORILLIA	M5	9.382	9.47582	9.570578	9.666284	9.762947	9.860576	9.959182	10.05877	10.15936	10.26096	10.36356	10.4672	10.57187	10.67759	10.78437	10.89221	11.00113	11.11114	11.22226	11.33448	11.44782	11.562301

Orillia TS	230	5 Georgian	ORILLIA	M6	9.292	9.38492	9.478769	9.573557	9.669292	9.765985	9.863645	9.962282	10.0619	10.16252	10.26415	10.36679	10.47046	10.57516	10.68091	10.78772	10.8956	11.00456	11.1146	11.22575	11.33801	11.451386
Orillia TS	230	5 Georgian	ORILLIA	M7	14.129	14.27029	14.41299	14.55712	14.70269	14.84972	14.99822	15.1482	15.29968	15.45268	15.60721	15.76328	15.92091	16.08012	16.24092	16.40333	16.56736	16.73304	16.90037	17.06937	17.24007	17.412466
Orillia TS	230	5 Georgian	ORILLIA	M8	9.899	9.99799	10.09797	10.19895	10.30094	10.40395	10.50799	10.61307	10.7192	10.82639	10.93465	11.044	11.15444	11.26599	11.37865	11.49243	11.60736	11.72343	11.84066	11.95907	12.07866	12.199448
Otonabee TS	230	3A Central	PETERBOROUGI	M27	14.706	14.85306	15.00159	15.15161	15.30312	15.45615	15.61072	15.76682	15.92449	16.08374	16.24457	16.40702	16.57109	16.7368	16.90417	17.07321	17.24394	17.41638	17.59054	17.76645	17.94411	18.123556
Otonabee TS	230	3A Central	PETERBOROUGI	M28	14.98	15.1298	15.2811	15.43391	15.58825	15.74413	15.90157	16.06059	16.22119	16.38341	16.54724	16.71271	16.87984	17.04864	17.21912	17.39131	17.56523	17.74088	17.91829	18.09747	18.27845	18.461231
Owen Sound TS	230	5 Georgian	OWEN SOUND	M21	15.415	15.56915	15.72484	15.88209	16.04091	16.20132	16.36333	16.52697	16.69224	16.85916	17.02775	17.19803	17.37001	17.54371	17.71914	17.89634	18.0753	18.25605	18.43861	18.623	18.80923	18.997322
Owen Sound TS	230	5 Georgian	OWEN SOUND	M22	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Owen Sound TS	230	5 Georgian	OWEN SOUND	M23	9.332	9.42532	9.519573	9.614769	9.710917	9.808026	9.906106	10.00517	10.10522	10.20627	10.30833	10.41142	10.51553	10.62069	10.72689	10.83416	10.9425	11.05193	11.16245	11.27407	11.38681	11.500682
Owen Sound TS	230	5 Georgian	OWEN SOUND	M24	16.432	16.59632	16.76228	16.92991	17.09921	17.2702	17.4429	17.61733	17.7935	17.97144	18.15115	18.33266	18.51599	18.70115	18.88816	19.07704	19.26781	19.46049	19.6551	19.85165	20.05016	20.250664
Owen Sound TS	230	5 Georgian	OWEN SOUND	M25	14.631	14.77731	14.92508	15.07433	15.22508	15.37733	15.5311	15.68641	15.84328	16.00171	16.16173	16.32334	16.48658	16.65144	16.81796	16.98614	17.156	17.32756	17.50083	17.67584	17.8526	18.031126
Owen Sound TS	230	5 Georgian	OWEN SOUND	M26	22.168	22.38968	22.61358	22.83971	23.06811	23.29879	23.53178	23.7671	24.00477	24.24482	24.48726	24.73214	24.97946	25.22925	25.48154	25.73636	25.99372	26.25366	26.5162	26.78136	27.04917	27.319665
Owen Sound TS	230	5 Georgian	OWEN SOUND	M28	6.005	6.06505	6.125701	6.186958	6.248827	6.311315	6.374429	6.438173	6.502555	6.56758	6.633256	6.699588	6.766584	6.83425	6.902593	6.971619	7.041335	7.111748	7.182866	7.254694	7.327241	7.4005136
Palmerston TS	115	1 West	LISTOWEL	M1	15.608	15.76408	15.92172	16.08094	16.24175	16.40416	16.56821	16.73389	16.90123	17.07024	17.24094	17.41335	17.58749	17.76336	17.94099	18.1204	18.30161	18.48462	18.66947	18.85616	19.04473	19.235173
Palmerston TS	115	1 West	LISTOWEL	M2	10.878	10.98678	11.09665	11.20761	11.31969	11.43289	11.54722	11.66269	11.77932	11.89711	12.01608	12.13624	12.2576	12.38018	12.50398	12.62902	12.75531	12.88286	13.01169	13.14181	13.27323	13.40596
Palmerston TS	115	1 West	LISTOWEL	M3	11.243	11.35543	11.46898	11.58367	11.69951	11.81651	11.93467	12.05402	12.17456	12.2963	12.41927	12.54346	12.66889	12.79558	12.92354	13.05277	13.1833	13.31513	13.44829	13.58277	13.7186	13.855783
Palmerston TS	115	1 West	LISTOWEL	M4	10.965	11.07465	11.1854	11.29725	11.41022	11.52433	11.63957	11.75596	11.87352	11.99226	12.11218	12.2333	12.35564	12.47919	12.60398	12.73002	12.85732	12.9859	13.11576	13.24691	13.37938	13.513178
Parry Sound TS	230	5 Georgian	PARRY SOUND	M1	8.307	8.39007	8.473971	8.55871	8.644298	8.73074	8.818048	8.906228	8.995291	9.085244	9.176096	9.267857	9.360536	9.454141	9.548682	9.644169	9.740611	9.838017	9.936397	10.03576	10.13612	10.23748
Parry Sound TS	230	5 Georgian	PARRY SOUND	M2	9.177	9.26877	9.361458	9.455072	9.549623	9.645119	9.74157	9.838986	9.937376	10.03675	10.13712	10.23849	10.34087	10.44428	10.54872	10.65421	10.76075	10.86836	10.97705	11.08682	11.19768	11.309661
Parry Sound TS	230	5 Georgian	PARRY SOUND	M4	6.694	6.76094	6.828549	6.896835	6.965803	7.035461	7.105816	7.176874	7.248643	7.321129	7.394341	7.468284	7.542967	7.618396	7.69458	7.771526	7.849241	7.927734	8.007011	8.087081	8.167952	8.2496316
Pembroke TS	115	3B East Ce	COBDEN	M1	16.987	17.15687	17.32844	17.50172	17.67674	17.85351	18.03204	18.21236	18.39449	18.57843	18.76422	18.95186	19.14138	19.33279	19.52612	19.72138	19.91859	20.11778	20.31896	20.52215	20.72737	20.934642
Pembroke TS	115	3B East Ce	COBDEN	M2	5.359	5.41259	5.466716	5.521383	5.576597	5.632363	5.688686	5.745573	5.803029	5.861059	5.91967	5.978867	6.038655	6.099042	6.160032	6.221633	6.283849	6.346687	6.410154	6.474256	6.538998	6.6043884
Pembroke TS	115	3B East Ce	COBDEN	M3	0.67	0.6767	0.683467	0.690302	0.697205	0.704177	0.711219	0.718331	0.725514	0.732769	0.740097	0.747498	0.754973	0.762522	0.770148	0.777849	0.785628	0.793484	0.801419	0.809433	0.817527	0.8257026
Picton TS	230	3B East Ce	PICTON	M5	16.086	16.24686	16.40933	16.57342	16.73916	16.90655	17.07561	17.24637	17.41883	17.59302	17.76895	17.94664	18.12611	18.30737	18.49044	18.67535	18.8621	19.05072	19.24123	19.43364	19.62798	19.824257
Picton TS	230	3B East Ce	PICTON	M6	7.58	7.6558	7.732358	7.809682	7.887778	7.966656	8.046323	8.126786	8.208054	8.290134	8.373036	8.456766	8.541334	8.626747	8.713015	8.800145	8.888146	8.977028	9.066798	9.157466	9.249041	9.3415309
Picton TS	230	3B East Ce	PICTON	M7	13.09	13.2209	13.35311	13.48664	13.62151	13.75772	13.8953	14.03425	14.17459	14.31634	14.4595	14.6041	14.75014	14.89764	15.04662	15.19708	15.34905	15.50255	15.65757	15.81415	15.97229	16.13201
Picton TS	230	3B East Ce	PICTON	M8	12.84	12.9684	13.09808	13.22906	13.36136	13.49497	13.62992	13.76622	13.90388	14.04292	14.18335	14.32518	14.46843	14.61312	14.75925	14.90684	15.05591	15.20647	15.35853	15.51212	15.66724	15.823913
Pleasant TS	230	2 West Ce	GUELPH*	M23	24.296	24.53896	24.78435	25.03219	25.28252	25.53534	25.79069	26.0486	26.30909	26.57218	26.8379	27.10628	27.37734	27.65111	27.92763	28.2069	28.48897	28.77386	29.0616	29.35222	29.64574	29.942195
Pleasant TS	230	2 West Ce	GUELPH*	M25	17.516	17.69116	17.86807	18.04675	18.22722	18.40949	18.59359	18.77952	18.96732	19.15699	19.34856	19.54205	19.73747	19.93484	20.13419	20.33553	20.53889	20.74428	20.95172	21.16124	21.37285	21.586577
Pleasant TS	230	2 West Ce	GUELPH*	M26	17.901	18.08001	18.26081	18.44342	18.62785	18.81413	19.00227	19.19229	19.38422	19.57806	19.77384	19.97158	20.17129	20.37301	20.57674	20.78251	20.99033	21.20023	21.41224	21.62636	21.84262	22.061048
Pleasant TS	230	2 West Ce	GUELPH*	M28	20.595	20.80095	21.00896	21.21905	21.43124	21.64555	21.86201	22.08063	22.30143	22.52445	22.74969	22.97719	23.20696	23.43903	23.67342	23.91016	24.14926	24.39075	24.63466	24.881	25.12981	25.381112
Port Hope TS	115	3A Central	PETERBOROUGI	M1	8.807	8.89507	8.984021	9.073861	9.1646	9.256246	9.348808	9.442296	9.536719	9.632086	9.728407	9.825691	9.923948	10.02319	10.12342	10.22465	10.3269	10.43017	10.53447	10.63982	10.74621	10.853676
Port Hope TS	115	3A Central	PETERBOROUGI	M15	6.958	7.02758	7.097856	7.168834	7.240523	7.312928	7.386057	7.459918	7.534517	7.609862	7.685961	7.76282	7.840449	7.918853	7.998042	8.078022	8.158802	8.24039	8.322794	8.406022	8.490082	8.5749831
Port Hope TS	115	3A Central	PETERBOROUGI	M16	12.492	12.61692	12.74309	12.87052	12.99923	13.12922	13.26051	13.39311	13.52705	13.66232	13.79894	13.93693	14.0763	14.21706	14.35923	14.50282	14.64785	14.79433	14.94227	15.0917	15.24261	15.39504
Port Hope TS	115	3A Central	PETERBOROUGI	M17	7.912	7.99112	8.071031	8.151742	8.233259	8.315592	8.398747	8.482735	8.567562	8.653238	8.73977	8.827168	8.91544	9.004594	9.09464	9.185586	9.277442	9.370217	9.463919	9.558558	9.654144	9.750685
Port Hope TS	115	3A Central	PETERBOROUGI	M18	5.323	5.37623	5.429992	5.484292	5.539135	5.594526	5.650472	5.706976	5.764046	5.821687	5.879904	5.938703	5.99809	6.058071	6.118651	6.179838	6.241636	6.304052	6.367093	6.430764	6.495072	6.5600223
Port Hope TS	115	3A Central	PETERBOROUGI	M2	14.321	14.46421	14.60885	14.75494	14.90249	15.05151	15.20203	15.35405	15.50759	15.66267	15.81929	15.97749	16.13726	16.29863	16.46162	16.62624	16.7925	16.96042	17.13003	17.30133	17.47434	17.649085
Port Hope TS	115	3A Central	PETERBOROUGI	M3	12.154	12.27554	12.3983	12.52228	12.6475	12.77398	12.90172	13.03073	13.16104	13.29265	13.42558	13.55983	13.69543	13.83239	13.97071	14.11042	14.25152	14.39404	14.53798	14.68336	14.83019	14.978492
Port Hope TS	115	3A Central	PETERBOROUGI	M4	14.025	14.16525	14.3069	14.44997	14.59447	14.74042	14.88782	15.0367	15.18707	15.33894	15.49233	15.64725	15.80372	15.96176	16.12138	16.28259	16.44542	16.60987	16.77597	16.94373	17.11317	17.284297
Red Lake TS	115	7 Northwes	DRYDEN	M4	6.798	6.86598	6.93464	7.003986	7.074026	7.144766	7.216214	7.288376	7.36126	7.434872	7.509221	7.584313	7.660157	7.736758	7.814126	7.892267	7.97119	8.050902	8.131411	8.212725	8.294852	8.3778004
Red Lake TS	115	7 Northwes	DRYDEN	M6	23.093	23.32393	23.55717	23.79274	24.03067	24.27098	24.51368	24.75882	25.00641	25.25647	25.50904	25.76413	26.02177	26.28199	26.54481	26.81026	27.07836	27.34914	27.62263	27.89886	28.17785	28.459627
Sidney TS	115	3B East Ce	TRENTON	M1	-9.561	-9.65661	-9.75318	-9.85071	-9.94921	-10.0487	-10.1492	-10.2507	-10.3532	-10.4567	-10.5613	-10.6669	-10.7736	-10.8813	-10.9901	-11.1	-11.211	-11.3231	-11.4364	-11.5507	-11.6662	-11.782899
Sidney TS	115	3B East Ce	TRENTON	M3	10.408	10.51208	10.6172	10.72337	10.83061	10.93891	11.0483	11.15878	11.27037	11.38308	11.49691	11.61188	11.72799	11.84527	11.96373	12.08336	12.2042	12.32624	12.4495	12.574	12.69974	12.826735
Sidney TS	115	3B East Ce	TRENTON	M4	18.304	18.48704	18.67191	18.85863	19.04722	19.23769	19.43006	19.62437	19.82061	20.01882	20.219	20.42119	20.62541	20.83166	21.03998	21.25038	21.46288	21.67751	21.89428	22.11323	22.33436	22.557702
Sidney TS	115	3B East Ce	TRENTON	M5	15.33	15.4833	15.63813	15.79451	15.95246	16.11198	16.2731	16.43583	16.60019	16.7662	16.93386	17.1032	17.27423	17.44697	17.62144	17.79765	17.97563	18.15539	18.33694	18.52031	18.70551	18.892568
Sidney TS	115	3B East Ce	TRENTON	M6	3.748	3.78548	3.823335	3.861568	3.900184	3.939186	3.978578	4.018363	4.058547	4.099132	4.140124	4.181525	4.22334	4.265574	4.308229	4.351312	4.394825	4.438773	4.483161	4.527992	4.573272	4.619005
Sidney TS	115	3B East Ce	TRENTON	M7	7.84	7.9184	7.997584	8.07756	8.158335	8.239919	8.322318	8.405541	8.489597	8.574493	8.660237	8.74684	8.834308	8.922651	9.011878	9.101997	9.193017	9.284947	9.377796	9.471574	9.56629	9.6619528
Sidney TS	115	3B East Ce	TRENTON	R8S	7.693	7.76993	7.847629	7.926106	8.005367	8.08542	8.166275	8.247937	8.330417	8.413721	8.497858	8.582837	8.668665	8.755352	8.842905	8.931334	9.020648	9.110854	9.201963	9.293982	9.386922	9.4807912
Sidney TS	115	3B East Ce	TRENTON	R9S	-8.231	-8.31331	-8.39644	-8.48041	-8.56521	-8.65086	-8.73737	-8.82475	-8.91299	-9.00212	-9.09214	-9.18307	-9.2749	-9.36765	-9.46132	-9.55594	-9.65149	-9.74801	-9.84549	-9.94394	-10.0434	-10.143818
Smiths Falls TS	230	4 East	PERTH	M21	8.17	8.2517	8.334217	8.417559	8.501735	8.586752	8.67262	8.759346	8.846939	8.935409	9.024763	9.11501	9.20616	9.298222	9.391204	9.485116	9.579968	9.675767	9.772525	9.87025	9.968953	10.068642
Smiths Falls TS	230	4 East	PERTH	M22	2.483	2.50783	2.532908	2.558237	2.58382	2.609658	2.635755	2.662112	2.688733	2.715621	2.742777	2.770205	2.797907	2.825886	2.854144	2.882686	2.911513	2.940628	2.970034	2.999735	3.029732	3.0600292
Smiths Falls TS	230	4 East	PERTH	M23	11.428	11.54228	11.6577	11.77428	11.89202	12.01094	12.13105	12.25236	12.37489	12.49864	12.62362	12.74986	12.87736	13.00613	13.13619	13.26755	13.40023	13.53423	13.66957	13.80627	13.94433	14.083775
Smiths Falls TS	230	4 East	PERTH	M24	3.74	3.7774	3.815174	3.853326	3.891859	3.930778	3.970085	4.009786	4.049884	4.090383	4.131287	4.1726	4.214326	4.256469	4.299034	4.342024	4.385444	4.429299	4.473592	4.518327	4.563511	4.6091459
Smiths Falls TS	230	4 East	PERTH	M25	15.372	15.52572	15.68098	15.83779	15.99616	16.15613	16.31769	16.48086	16.64567	16.81213	16.98025	17.15005	17.32155	17.49477	17.66972	17.84641	18.02488	18.20513	18.38718	18.57105	18.75676	18.944329
Smiths Falls TS	230	4 East	PERTH	M26	11.835	11.95335	12.07288	12.19361	12.31555	12.4387	12.56309	12.68872	12.81561	12.94377	13.0732	13.20393	13.33597	13.46933	13.60403	13.74007	13.87747	14.01624	14.15641	14.29797	14.44095	14.585359
Smiths Falls TS	230	4 East	PERTH	M28	1.682	1.69882	1.715808	1.732966	1.750296	1.767799	1.785477	1.803332	1.821365	1.839579	1.857974	1.876554	1.89532	1.914273	1.933416	1.95275	1.972277	1.992	2.01192	2.032039	2.05236	2.0728832
South March TS	230	4 East	ARNPRIOR	M3	8.441	8.52541	8.610664	8.696771	8.783738	8.871576	8.960292	9.049895	9.140393	9.231797	9.324115	9.417357	9.51153	9.606645	9.702712	9.799739	9.897736	9.996714	10.09668	10.19765	10.29962	10.40262
South March TS	230	4 East	ARNPRIOR	M5	19.08	19.2708	19.46351	19.65814	19.85472	20.05327	20.2538	20.45634	20.66091	20.86752	21.07619	21.28695	21.49982	21.71482	21.93197	22.15129	22.3728	22.59653	22.82249	23.05072	23.28123	23.514038
St.Isidore TS	230	4 East	VANKLEEK HILL	M1	5.017	5.06717	5.117842	5.16902	5.22071	5.272917	5.325647	5.378903	5.432692	5.487019	5.541889	5.597308	5.653281	5.709814	5.766912	5.824581	5.882827	5.941655	6.001072	6.061083	6.121693	6.1829104
St.Isidore TS	230	4 East	VANKLEEK HILL	M2	10.426	10.53026	10.63556	10.74192	10.84934	10.95783	11.06741	11.17808	11.28986	11.40276	11.51679	11.63196	11.74828	11.86576	11.98442	12.10426	12.2253	12.34756	12.47103	12.59574	12.7217	12.848918
St.Isidore TS	230	4 East	VANKLEEK HILL	M3	2.643	2.66943	2.696124	2.723086	2.750316	2.77782	2.805598	2.833654	2.86199	2.890061	2.919516	2.948711	2.978199	3.007981	3.03806	3.068441	3.099125	3.130117	3.161418	3.193032	3.224962	3.2572119
St.Isidore TS	230	4 East	VANKLEEK HILL	M4	13.526	13.66126	13.79787	13.93585	14.07521	14.21596	14.35812	14.5017	14.64672	14.79319	14.94112	15.09053	15.24144	15.39385	15.54779	15.70327	15.8603	16.0189	16.17909	16.34088	16.50429	16.669333
St.Lawrence TS	230	4 East	WINCHESTER	M24	2.758	2.78558	2.813436	2.84157	2.869986	2.898686	2.927673	2.956949	2.986519	3.016384	3.046548	3.077013	3.107783	3.138861	3.17025	3.201952	3.233972	3.266312	3.298975	3.331964	3.365284	3.398937
St.Lawrence TS	230	4 East	WINCHESTER	M25	8.478	8.56278	8.648408	8.734892	8.822241	8.910463	8.999568	9.089564	9.180459	9.272264	9.364986	9.458636	9.553223	9.648755	9.745242	9.842695	9.941122	10.04053	10.14094	10.24235	10.34477	10.448219
St.Lawrence TS	230	4 East	WINCHESTER	M26	9.685	9.78185	9.879669	9.978465	10.07825	10.17903	10.28082	10.38363	10.48747	10.59234	10.69827	10.80525	10.9133	11.02243	11.13266	11.24398	11.35642	11.46999	11.58469	11.70054	11.81754	11.935716
St.Lawrence TS	230	4 East	WINCHESTER	M27	0.682	0.68882	0.695708	0.702665	0.709692	0.716789	0.723957	0.731196	0.738508	0.745893	0.753352	0.760886	0.768495	0.77618	0.783941	0.791781	0.799699	0.807696	0.815773	0.82393	0.83217	0.8404913
St.Lawrence TS	230	4 East	WINCHESTER	M28	-0.011	-0.01111	-0.01122	-0.01133	-0.01145	-0.01156	-0.01168	-0.01179	-0.01191	-0.01203	-0.01215	-0.01227	-0.0124	-0.01252	-0.01264	-0.01277	-0.0129	-0.01303	-0.01316	-0.01329	-0.01342	-0.0135563
Stayner TS	230	5 Georgian	BARRIE	M1	5.353	5.40653	5.460595	5.515201	5.570353	5.626057	5.682317	5.739141	5.796532	5.854497	5.913042	5.972173	6.031894	6.092213	6.153135	6.214667	6.276813	6.339582	6.402977	6.467007	6.531677	6.5969941

Stayner TS	230	5 Georgian	BARRIE	M2	13.164	13.29564	13.4286	13.56288	13.69851	13.8355	13.97385	14.11359	14.25473	14.39727	14.54125	14.68666	14.83352	14.98186	15.13168	15.283	15.43583	15.59018	15.74609	15.90355	16.06258	16.223208
Stayner TS	230	5 Georgian	BARRIE	M3	0.021	0.02121	0.021422	0.021636	0.021853	0.022071	0.022292	0.022515	0.02274	0.022967	0.023197	0.023429	0.023663	0.0239	0.024139	0.02438	0.024624	0.02487	0.025119	0.02537	0.025624	0.0258802
Stayner TS	230	5 Georgian	BARRIE	M4	24.486	24.73086	24.97817	25.22795	25.48023	25.73503	25.99238	26.25231	26.51483	26.77998	27.04778	27.31826	27.59144	27.86735	28.14603	28.42749	28.71176	28.99888	29.28887	29.58176	29.87757	30.176349
Stayner TS	230	5 Georgian	BARRIE	M5	0.021	0.02121	0.021422	0.021636	0.021853	0.022071	0.022292	0.022515	0.02274	0.022967	0.023197	0.023429	0.023663	0.0239	0.024139	0.02438	0.024624	0.02487	0.025119	0.02537	0.025624	0.0258802
Stewartville TS	115	4 East	ARNPRIOR	M1	5.319	5.37219	5.425912	5.480171	5.534973	5.590322	5.646226	5.702688	5.759715	5.817312	5.875485	5.93424	5.993582	6.053518	6.114053	6.175194	6.236946	6.299315	6.362308	6.425932	6.490191	6.5550927
Stewartville TS	115	4 East	ARNPRIOR	M3	13.143	13.27443	13.40717	13.54125	13.67666	13.81343	13.95156	14.09107	14.23199	14.37431	14.51805	14.66323	14.80986	14.95796	15.10754	15.25861	15.4112	15.56531	15.72097	15.87818	16.03696	16.197327
Thornton TS	230	3A Central	BOWMANVILLE	M1	3.565	3.60065	3.636657	3.673023	3.709753	3.746851	3.784319	3.822163	3.860384	3.898988	3.937978	3.977358	4.017131	4.057303	4.097876	4.138854	4.180243	4.222045	4.264266	4.306908	4.349977	4.3934773
Thornton TS	230	3A Central	BOWMANVILLE	M6	11.825	11.94325	12.06268	12.18331	12.30514	12.42819	12.55248	12.678	12.80478	12.93283	13.06216	13.19278	13.32471	13.45795	13.59253	13.72846	13.86574	14.0044	14.14444	14.28589	14.42875	14.573035
Thornton TS	230	3A Central	BOWMANVILLE	M7	6.914	6.98314	7.052971	7.123501	7.194736	7.266683	7.33935	7.412744	7.486871	7.56174	7.637357	7.713731	7.790868	7.868777	7.947465	8.026939	8.107209	8.188281	8.270164	8.352865	8.436394	8.5207579
Thornton TS	230	3A Central	BOWMANVILLE	M8	11.6	11.716	11.83316	11.95149	12.07101	12.19172	12.31363	12.43677	12.56114	12.68675	12.81362	12.94175	13.07117	13.20188	13.3339	13.46724	13.60191	13.73793	13.87531	14.01406	14.1542	14.295747
Trout Lake TS	230	6 Northeas	NIPISSING	M3	9.923	10.02223	10.12245	10.22368	10.32591	10.42917	10.53346	10.6388	10.74519	10.85264	10.96117	11.07078	11.18148	11.2933	11.40623	11.52029	11.6355	11.75185	11.86937	11.98807	12.10795	12.229025
Trout Lake TS	230	6 Northeas	NIPISSING	M7	7.819	7.89719	7.976162	8.055924	8.136483	8.217848	8.300026	8.383026	8.466857	8.551525	8.63704	8.723411	8.810645	8.898751	8.987739	9.077616	9.168392	9.260076	9.352677	9.446204	9.540666	9.6360726
Trout Lake TS	230	6 Northeas	NIPISSING	M8	9.577	9.67277	9.769498	9.867193	9.965865	10.06552	10.16618	10.26784	10.37052	10.47422	10.57897	10.68476	10.7916	10.89952	11.00851	11.1186	11.22979	11.34208	11.4555	11.57006	11.68576	11.802618
Wallace TS	230	3B East Ce	BANCROFT	16M1	10.749	10.85649	10.96505	11.07471	11.18545	11.29731	11.41028	11.52438	11.63963	11.75602	11.87358	11.99232	12.11224	12.23336	12.3557	12.47926	12.60405	12.73009	12.85739	12.98596	13.11582	13.246981
Wallace TS	230	3B East Ce	BANCROFT	16M4	9.685	9.78185	9.879669	9.978465	10.07825	10.17903	10.28082	10.38363	10.48747	10.59234	10.69827	10.80525	10.9133	11.02243	11.13266	11.24398	11.35642	11.46999	11.58469	11.70054	11.81754	11.935716
Wallace TS	230	3B East Ce	BANCROFT	16M6	10.442	10.54642	10.65188	10.7584	10.86599	10.97465	11.08439	11.19524	11.30719	11.42026	11.53446	11.64981	11.76631	11.88397	12.00281	12.12284	12.24407	12.36651	12.49017	12.61507	12.74122	12.868637
Waubaushene TS	230	5 Georgian	PENETANG	M1	11.379	11.49279	11.60772	11.7238	11.84103	11.95944	12.07904	12.19983	12.32183	12.44504	12.5695	12.69519	12.82214	12.95036	13.07987	13.21067	13.34277	13.4762	13.61096	13.74707	13.88454	14.023388
Waubaushene TS	230	5 Georgian	PENETANG	M2	16.44	16.6044	16.77044	16.93815	17.10753	17.27861	17.45139	17.62591	17.80216	17.98019	18.15999	18.34159	18.525	18.71025	18.89736	19.08633	19.27719	19.46996	19.66466	19.86131	20.05992	20.260523
Waubaushene TS	230	5 Georgian	PENETANG	M3	13.094	13.22494	13.35719	13.49076	13.62567	13.76193	13.89954	14.03854	14.17893	14.32071	14.46392	14.60856	14.75465	14.90219	15.05122	15.20173	15.35374	15.50728	15.66236	15.81898	15.97717	16.13694
Waubaushene TS	230	5 Georgian	PENETANG	M4	12.483	12.60783	12.73391	12.86125	12.98986	13.11976	13.25096	13.38347	13.5173	13.65247	13.789	13.92689	14.06616	14.20682	14.34889	14.49238	14.6373	14.78367	14.93151	15.08082	15.23163	15.383949
Waubaushene TS	230	5 Georgian	PENETANG	M5	11.998	12.11798	12.23916	12.36155	12.48517	12.61002	12.73612	12.86348	12.99211	13.12204	13.25326	13.38579	13.51965	13.65484	13.79139	13.92931	14.0686	14.20928	14.35138	14.49489	14.63984	14.786239
Waubaushene TS	230	5 Georgian	PENETANG	M6	3.031	3.06131	3.091923	3.122842	3.154071	3.185611	3.217468	3.249642	3.282139	3.31496	3.34811	3.381591	3.415407	3.449561	3.484056	3.518897	3.554086	3.589627	3.625523	3.661778	3.698396	3.73538
Waubaushene TS	230	5 Georgian	PENETANG	M7	9.904	10.00304	10.10307	10.2041	10.30614	10.4092	10.5133	10.61843	10.72461	10.83186	10.94018	11.04958	11.16008	11.27168	11.38439	11.49824	11.61322	11.72935	11.84664	11.96511	12.08476	12.20561
Whitby TS	230	3A Central	BOWMANVILLE	M22	19.37	19.5637	19.75934	19.95693	20.1565	20.35806	20.56165	20.76726	20.97493	21.18468	21.39653	21.6105	21.8266	22.04487	22.26532	22.48797	22.71285	22.93998	23.16938	23.40107	23.63508	23.871432
Wilson TS	230	3A Central	BOWMANVILLE	M11	24.486	24.73086	24.97817	25.22795	25.48023	25.73503	25.99238	26.25231	26.51483	26.77998	27.04778	27.31826	27.59144	27.86735	28.14603	28.42749	28.71176	28.99888	29.28887	29.58176	29.87757	30.176349
Wilson TS	230	3A Central	BOWMANVILLE	M12	22.145	22.36645	22.59011	22.81602	23.04418	23.27462	23.50736	23.74244	23.97986	24.21966	24.46186	24.70648	24.95354	25.20308	25.45511	25.70966	25.96675	26.22642	26.48869	26.75357	27.02111	27.29132
Wilson TS	230	3A Central	BOWMANVILLE	M13	8.596	8.68196	8.76878	8.856467	8.945032	9.034482	9.124827	9.216075	9.308236	9.401319	9.495332	9.590285	9.686188	9.78305	9.88088	9.979689	10.07949	10.18028	10.28208	10.3849	10.48875	10.593641
Wilson TS	230	3A Central	BOWMANVILLE	M14	8.898	8.98698	9.07685	9.167618	9.259294	9.351887	9.445406	9.53986	9.635259	9.731612	9.828928	9.927217	10.02649	10.12675	10.22802	10.3303	10.4336	10.53794	10.64332	10.74975	10.85725	10.965823
Wilson TS	230	3A Central	BOWMANVILLE	M15	18.396	18.57996	18.76576	18.95342	19.14295	19.33438	19.52772	19.723	19.92023	20.11943	20.32063	20.52383	20.72907	20.93636	21.14573	21.35718	21.57076	21.78646	22.00433	22.22437	22.44662	22.671082
Wilson TS	230	3A Central	BOWMANVILLE	M16	12.415	12.53915	12.66454	12.79119	12.9191	13.04829	13.17877	13.31056	13.44367	13.5781	13.71388	13.85102	13.98953	14.12943	14.27072	14.41343	14.55756	14.70314	14.85017	14.99867	15.14866	15.300146
Wilson TS	230	3A Central	BOWMANVILLE	M17	27.545	27.82045	28.09865	28.37964	28.66344	28.95007	29.23957	29.53197	29.82729	30.12556	30.42682	30.73108	31.0384	31.34878	31.66227	31.97889	32.29868	32.62167	32.94788	33.27736	33.61013	33.946236
Wilson TS	230	3A Central	BOWMANVILLE	M8	28.19	28.4719	28.75662	29.04419	29.33463	29.62797	29.92425	30.2235	30.52573	30.83099	31.1393	31.45069	31.7652	32.08285	32.40368	32.72771	33.05499	33.38554	33.7194	34.05659	34.39716	34.741129
Wingham TS	230	1 West	WALKERTON	M3	12.341	12.46441	12.58905	12.71494	12.84209	12.97052	13.10022	13.23122	13.36353	13.49717	13.63214	13.76846	13.90615	14.04521	14.18566	14.32752	14.47079	14.6155	14.76166	14.90927	15.05837	15.208949
Wingham TS	230	1 West	WALKERTON	M4	4.208	4.25008	4.292581	4.335507	4.378862	4.42265	4.466877	4.511546	4.556661	4.602228	4.64825	4.694732	4.74168	4.789097	4.836987	4.885357	4.934211	4.983553	5.033389	5.083722	5.13456	5.1859053
Wingham TS	230	1 West	WALKERTON	M5	12.127	12.24827	12.37075	12.49446	12.6194	12.7456	12.87305	13.00179	13.1318	13.26312	13.39575	13.52971	13.66501	13.80166	13.93967	14.07907	14.21986	14.36206	14.50568	14.65074	14.79724	14.945217
Wingham TS	230	1 West	WALKERTON	M6	15.13	15.2813	15.43411	15.58845	15.74434	15.90178	16.0608	16.22141	16.38362	16.54746	16.71293	16.88006	17.04886	17.21935	17.39154	17.56546	17.74111	17.91853	18.09771	18.27869	18.46148	18.64609
Woodbridge TS	230	3A Central	NEWMARKET*	M12	21	21.21	21.4221	21.63632	21.85268	22.07121	22.29192	22.51484	22.73999	22.96739	23.19706	23.42904	23.66333	23.89996	24.13896	24.38035	24.62415	24.87039	25.1191	25.37029	25.62399	25.880231
Woodbridge TS	230	3A Central	NEWMARKET*	M14	14.706	14.85306	15.00159	15.15161	15.30312	15.45615	15.61072	15.76682	15.92449	16.08374	16.24457	16.40702	16.57109	16.7368	16.90417	17.07321	17.24394	17.41638	17.59054	17.76645	17.94411	18.123556
Woodbridge TS	230	3A Central	NEWMARKET*	M16	12.022	12.14222	12.26364	12.38628	12.51014	12.63524	12.7616	12.88921	13.0181	13.14828	13.27977	13.41256	13.54669	13.68216	13.81898	13.95717	14.09674	14.23771	14.38008	14.52389	14.66912	14.815816

Financial Evaluation Summary - Alt. 1

Plan 0

0

Study Period - No. of Years 60

0

(A) Discounted Cash Flows (Note 1) $K

	Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Incremental Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental OM&A (Costs) / Cost Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario Capital Tax and Municipal Tax	(1,447)	0	0	(6)	(12)	(16)	(19)	(22)	(26)	(29)	(32)	(35)	(37)	(44)	(43)	(43)	(42)	(41)	(44)	(44)	(47)	(48)	(47)	(45)
Operating Cash Flows	**(1,447)**	**0**	**0**	**(6)**	**(12)**	**(16)**	**(19)**	**(22)**	**(26)**	**(29)**	**(32)**	**(35)**	**(37)**	**(44)**	**(43)**	**(43)**	**(42)**	**(41)**	**(44)**	**(44)**	**(47)**	**(48)**	**(47)**	**(45)**
Income Tax Recovery/(Provision)	463	0	0	2	4	5	6	7	8	9	10	11	12	14	14	14	13	13	14	14	15	15	15	15
Net Operating Cash Flows	**(984)**	**0**	**0**	**(4)**	**(8)**	**(11)**	**(13)**	**(15)**	**(17)**	**(19)**	**(22)**	**(24)**	**(25)**	**(30)**	**(29)**	**(29)**	**(29)**	**(28)**	**(30)**	**(30)**	**(32)**	**(33)**	**(32)**	**(31)**
Capital Expenditures	**(49,500)**	**0**	**0**	**(4,500)**	**(4,500)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(6,000)**	**0**	**(1,500)**	**0**	**0**	**(3,000)**	**(1,500)**	**(3,000)**	**(1,500)**	**0**	**0**
CCA Tax Shield	14,637	0	0	58	168	251	307	360	408	452	493	530	564	634	660	627	596	548	543	557	570	582	555	510
Proceeds on disposal of depreciable property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Change in Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Project Terminal Value/Commitment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Cash Flows	**(35,847)**	**0**	**0**	**(4,447)**	**(4,340)**	**(2,760)**	**(2,705)**	**(2,655)**	**(2,610)**	**(2,568)**	**(2,529)**	**(2,494)**	**(2,461)**	**(5,396)**	**631**	**(903)**	**567**	**521**	**(2,487)**	**(973)**	**(2,462)**	**(951)**	**523**	**479**
Discount Factor @ **5.73%**		0.9458	0.8946	0.8461	0.8003	0.7570	0.7159	0.6772	0.6405	0.6058	0.5730	0.5419	0.5126	0.4848	0.4586	0.4337	0.4102	0.3880	0.3670	0.3471	0.3283	0.3105	0.2937	0.2778
Net Present Value (Discounted Cash Flows)	0	0	0	(3,762)	(3,473)	(2,089)	(1,937)	(1,798)	(1,671)	(1,555)	(1,449)	(1,351)	(1,262)	(2,616)	290	(391)	233	202	(913)	(338)	(808)	(295)	154	133
Cum. Net Present Value **(23,837)**		**0**	**0**	**(3,762)**	**(7,236)**	**(9,325)**	**(11,262)**	**(13,060)**	**(14,731)**	**(16,287)**	**(17,736)**	**(19,087)**	**(20,349)**	**(22,965)**	**(22,675)**	**(23,067)**	**(22,834)**	**(22,632)**	**(23,544)**	**(23,882)**	**(24,691)**	**(24,986)**	**(24,832)**	**(24,699)**

Note 1: Information in Section A is presented using cash flow conventions - positive amounts for cash inflows and negative amounts for cash outflows.

(B) NPV Summary and Profitability Index (Note 2) $K

A. PV - Revenue	**-**
B. PV - Incremental OM&A (Costs) / Cost Savings	**-**
C. PV - Ontario Capital Tax and Municipal Tax	**(485)**
D. PV - Taxes	**155**
E. PV - CCA Tax Shield	**5,585**
F. PV - Proceeds on disposal of depreciable property	**-**
G. PV - Change in Working capital	**-**
H. PV - Project Terminal value / (commitment)	**20**
I. Sub-total of above **(A+B+C+D+E+F+G+H)**	**5,275**
J. PV - Capital Expenditures	**(29,112)**
Cum. Net Present Value	**(23,837)**
Profitability Index (PI) = I/(J*-1)	**0.18** (for value enhancing projects, PI should be >= **1.1**)

Note 2: Information in Section B is presented using cash flow conventions - positive amounts for cash inflows and negative amounts for cash outflows.

(D) Other Financial Measurements

(1) **After-Tax IRR for this Alternative** - % **#DIV/0!**
(Please note: if the above result is #DIV/0! or #NUM!, it is not an error; it means that the project IRR cannot be computed with the given cash flows.)

(2) **Payback** (discounted) - No. of Years **N/A**
(**from project in-service date** to Year when cum. NPV turns 0)

(3) **Project Terminal Value / Commitment** - $K **20**
as a % of Cum. Net Present Value -0.1%

			Voltage (kV)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPV-Feeder Expansion (Dx)	#of overloaded feeders	for	13.8	3																					
$23,837,000	#of overloaded feeders	for	22	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NPV-Feeder Expansion (DG)	#of overloaded feeders	for	25	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
$166,217,000	#of overloaded feeders	for	27	3		1				2						1							1	1
	#of overloaded feeders	for	44	7		3					1	1				3		1			2	1	1	
	Total#of overloaded feeders		33	13	0	4	0	0	0	2	1	1	1	0	0	4	0	1	0	0	2	1	2	1
	Acutal # overloaded feeders to be fixed		33	0	0	3	3	2	2	2	2	2	2	2	2	4	0	1	0	0	2	1	2	1
% benefit for Dx per DG invest	km feeders required for modification		165	0	0	15	15	10	10	10	10	10	10	10	10	20	0	5	0	0	10	5	10	5
2.9	cost of new/modified feeders		49500	0	0	4500	4500	3000	3000	3000	3000	3000	3000	3000	3000	6000	0	1500	0	0	3000	1500	3000	1500

					Peak Load (MW)																				
STATION	STATION kV	Provincial Lines Zone	Lines Operations Centre	FEEDER	Now	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Murray TS	115	2 West Cei	LINCOLN	M10	20.034	20.23434	20.43668	20.64105	20.84746	21.05594	21.26649	21.47916	21.69395	21.91089	22.13	22.3513	22.57481	22.80056	23.02857	23.25885	23.49144	23.72635	23.96362	24.20325	24.44529	24.68974
Murray TS	115	2 West Cei	LINCOLN	M11	4.199	4.24099	4.2834	4.326234	4.369496	4.413191	4.457323	4.501896	4.546915	4.592384	4.638308	4.684691	4.731538	4.778854	4.826642	4.874909	4.923658	4.972894	5.022623	5.072849	5.123578	5.1748138
Murray TS	115	2 West Cei	LINCOLN	M13	1.821	1.83921	1.857602	1.876178	1.89494	1.913889	1.933028	1.952358	1.971882	1.991601	2.011517	2.031632	2.051948	2.072468	2.093193	2.114124	2.135266	2.156618	2.178185	2.199966	2.221966	2.2441857
Murray TS	115	2 West Cei	LINCOLN	M25	17.996	18.17596	18.35772	18.5413	18.72671	18.91398	19.10312	19.29415	19.48709	19.68196	19.87878	20.07757	20.27834	20.48113	20.68594	20.8928	21.10173	21.31274	21.52587	21.74113	21.95854	22.178125
Stanley TS	115	2 West Cei	LINCOLN	M2	0.18	0.1818	0.183618	0.185454	0.187309	0.189182	0.191074	0.192984	0.194914	0.196863	0.198832	0.20082	0.202829	0.204857	0.206905	0.208974	0.211064	0.213175	0.215307	0.21746	0.219634	0.2218305
Thorold TS	115	2 West Cei	LINCOLN	M1	3.284	3.31684	3.350008	3.383508	3.417344	3.451517	3.486032	3.520892	3.556101	3.591662	3.627579	3.663855	3.700493	3.737498	3.774873	3.812622	3.850748	3.889256	3.928148	3.96743	4.007104	4.0471751
Thorold TS	115	2 West Cei	LINCOLN	M2	8.176	8.25776	8.340338	8.423741	8.507978	8.593058	8.678989	8.765779	8.853436	8.941971	9.03139	9.121704	9.212921	9.305051	9.398101	9.492082	9.587003	9.682873	9.779702	9.877499	9.976274	10.076037
Thorold TS	115	2 West Cei	LINCOLN	M3	2.091	2.11191	2.133029	2.154359	2.175903	2.197662	2.219639	2.241835	2.264253	2.286896	2.309765	2.332863	2.356191	2.379753	2.403551	2.427586	2.451862	2.476381	2.501144	2.526156	2.551417	2.5769315
Thorold TS	115	2 West Cei	LINCOLN	M5	0.615	0.62115	0.627362	0.633635	0.639971	0.646371	0.652835	0.659363	0.665957	0.672616	0.679343	0.686136	0.692997	0.699927	0.706927	0.713996	0.721136	0.728347	0.735631	0.742987	0.750417	0.757921
Coniston TS	115	6 Northeas	SUDBURY*	M1	4.9	4.949	4.99849	5.048475	5.09896	5.149949	5.201449	5.253463	5.305998	5.359058	5.412648	5.466775	5.521443	5.576657	5.632424	5.688748	5.745635	5.803092	5.861123	5.919734	5.978931	6.0387205
Coniston TS	115	6 Northeas	SUDBURY*	M5	3.1	3.131	3.16231	3.193933	3.225872	3.258131	3.290712	3.32362	3.356856	3.390424	3.424329	3.458572	3.493158	3.528089	3.56337	3.599004	3.634994	3.671344	3.708057	3.745138	3.782589	3.820415
North Bay TS	115	6 Northeas	NIPISSING	M1	4.076	4.11676	4.157928	4.199507	4.241502	4.283917	4.326756	4.370024	4.413724	4.457861	4.50244	4.547464	4.592939	4.638868	4.685257	4.732109	4.779431	4.827225	4.875497	4.924252	4.973495	5.0232295
Hearst TS	115	6 Northeas	KAPUSKASING	M1	1.94	1.9594	1.978994	1.998784	2.018772	2.038959	2.059349	2.079943	2.100742	2.121749	2.142967	2.164397	2.186041	2.207901	2.22998	2.25228	2.274803	2.297551	2.320526	2.343731	2.367169	2.3908404
Hearst TS	115	6 Northeas	KAPUSKASING	M2	13.69	13.8269	13.96517	14.10482	14.24587	14.38833	14.53221	14.67753	14.82431	14.97255	15.12228	15.2735	15.42623	15.5805	15.7363	15.89366	16.0526	16.21313	16.37526	16.53901	16.7044	16.871446
Kapuskasing TS	230	6 Northeas	KAPUSKASING	M1	5.802	5.86002	5.91862	5.977806	6.037584	6.09796	6.15894	6.220529	6.282735	6.345562	6.409018	6.473108	6.537839	6.603217	6.669249	6.735942	6.803301	6.871334	6.940048	7.009448	7.079543	7.150338
Kapuskasing TS	230	6 Northeas	KAPUSKASING	M3	1.157	1.16857	1.180256	1.192058	1.203979	1.216019	1.228179	1.240461	1.252865	1.265394	1.278048	1.290828	1.303737	1.316774	1.329942	1.343241	1.356673	1.37024	1.383943	1.397782	1.41176	1.4258775
Kapuskasing TS	230	6 Northeas	KAPUSKASING	M4	4.074	4.11474	4.155887	4.197446	4.239421	4.281815	4.324633	4.367879	4.411558	4.455674	4.500231	4.545233	4.590685	4.636592	4.682958	4.729788	4.777085	4.824856	4.873105	4.921836	4.971054	5.0207648
Port Arthur TS #1	115	7 Northwes	THUNDER BAY	M27	1.258	1.27058	1.283286	1.296119	1.30908	1.322171	1.335392	1.348746	1.362234	1.375856	1.389615	1.403511	1.417546	1.431721	1.446039	1.460499	1.475104	1.489855	1.504754	1.519801	1.534999	1.5503491
Port Arthur TS #1	115	7 Northwes	THUNDER BAY	M6	4.543	4.58843	4.634314	4.680657	4.727464	4.774739	4.822486	4.870711	4.919418	4.968612	5.018298	5.068481	5.119166	5.170358	5.222061	5.274282	5.327025	5.380295	5.434098	5.488439	5.543323	5.5987566
Agincourt TS	230	3A Central	BOWMANVILLE*	M1	1.423	1.43723	1.451602	1.466118	1.48078	1.495587	1.510543	1.525649	1.540905	1.556314	1.571877	1.587596	1.603472	1.619507	1.635702	1.652059	1.668579	1.685265	1.702118	1.719139	1.73633	1.7536937
Agincourt TS	230	3A Central	BOWMANVILLE*	M2	1.371	1.38471	1.398557	1.412543	1.426668	1.440935	1.455344	1.469898	1.484597	1.499443	1.514437	1.529581	1.544877	1.560326	1.575929	1.591688	1.607605	1.623681	1.639918	1.656317	1.672881	1.6896094
Allanburg TS	230	2 West Cei	LINCOLN	M6	2.659	2.68559	2.712446	2.73957	2.766966	2.794636	2.822582	2.850808	2.879316	2.908109	2.93719	2.966562	2.996228	3.02619	3.056452	3.087016	3.117887	3.149065	3.180556	3.212362	3.244485	3.2769302
Allanburg TS	230	2 West Cei	LINCOLN	M7	10.89	10.9989	11.10889	11.21998	11.33218	11.4455	11.55995	11.67555	11.79231	11.91023	12.02933	12.14963	12.27112	12.39384	12.51777	12.64295	12.76938	12.89708	13.02605	13.15631	13.28787	13.420748
Allanburg TS	230	2 West Cei	LINCOLN	M8	6.186	6.24786	6.310339	6.373442	6.437176	6.501548	6.566564	6.632229	6.698552	6.765537	6.833192	6.901524	6.97054	7.040245	7.110647	7.181754	7.253571	7.326107	7.399368	7.473362	7.548096	7.6235765
Aylmer TS	115	1 West	AYLMER	M2	3.513	3.54813	3.583611	3.619447	3.655642	3.692198	3.72912	3.766411	3.804076	3.842116	3.880538	3.919343	3.958536	3.998122	4.038103	4.078484	4.119269	4.160461	4.202066	4.244087	4.286528	4.3293929
Beamsville TS	115	2 West Cei	LINCOLN	M2	12.477	12.60177	12.72779	12.85507	12.98362	13.11345	13.24459	13.37703	13.5108	13.64591	13.78237	13.92019	14.0594	14.19999	14.34199	14.48541	14.63026	14.77657	14.92433	15.07358	15.22431	15.376554
Beamsville TS	115	2 West Cei	LINCOLN	M3	11.703	11.82003	11.93823	12.05761	12.17819	12.29997	12.42297	12.5472	12.67267	12.7994	12.92739	13.05667	13.18723	13.31911	13.4523	13.58682	13.72269	13.85991	13.99851	14.1385	14.27988	14.422683
Beamsville TS	115	2 West Cei	LINCOLN	M4	3.72	3.7572	3.794772	3.83272	3.871047	3.909757	3.948855	3.988344	4.028227	4.068509	4.109194	4.150286	4.191789	4.233707	4.276044	4.318805	4.361993	4.405612	4.449669	4.494165	4.539107	4.584498
Bilberry Creek TS	115	4 East	WINCHESTER	M3	8.919	9.00819	9.098272	9.189255	9.281147	9.373959	9.467698	9.562375	9.657999	9.754579	9.852125	9.950646	10.05015	10.15065	10.25216	10.35468	10.45823	10.56281	10.66844	10.77512	10.88287	10.991704
Bilberry Creek TS	115	4 East	WINCHESTER	M4	7.47	7.5447	7.620147	7.696348	7.773312	7.851045	7.929556	8.008851	8.08894	8.169829	8.251527	8.334043	8.417383	8.501557	8.586572	8.672438	8.759162	8.846754	8.935222	9.024574	9.11482	9.2059678
Brant TS	115	2 West Cei	SIMCOE	M14	5.698	5.75498	5.81253	5.870655	5.929362	5.988655	6.048542	6.109027	6.170118	6.231819	6.294137	6.357078	6.420649	6.484856	6.549704	6.615201	6.681353	6.748167	6.815648	6.883805	6.952643	7.0221693
Brant TS	115	2 West Cei	SIMCOE	M21	7.458	7.53258	7.607906	7.683985	7.760825	7.838433	7.916817	7.995985	8.075945	8.156705	8.238272	8.320655	8.403861	8.4879	8.572779	8.658506	8.745092	8.832542	8.920868	9.010077	9.100177	9.1911791
Brant TS	115	2 West Cei	SIMCOE	M22	2.839	2.86739	2.896064	2.925025	2.954275	2.983818	3.013656	3.043792	3.07423	3.104972	3.136022	3.167382	3.199056	3.231047	3.263357	3.295991	3.328951	3.36224	3.395863	3.429821	3.46412	3.4987607
Brantford TS	230	2 West Cei	SIMCOE	M25	13.544	13.67944	13.81623	13.9544	14.09394	14.23488	14.37723	14.521	14.66621	14.81287	14.961	15.11061	15.26172	15.41434	15.56848	15.72416	15.88141	16.04022	16.20062	16.36263	16.52625	16.691516
Brantford TS	230	2 West Cei	SIMCOE	M27	16.542	16.70742	16.87449	17.04324	17.21367	17.38581	17.55967	17.73526	17.91262	18.09174	18.27266	18.45539	18.63994	18.82634	19.0146	19.20475	19.3968	19.59076	19.78667	19.98454	20.18438	20.386227
Brantford TS	230	2 West Cei	SIMCOE	M28	13.419	13.55319	13.68872	13.82561	13.96387	14.1035	14.24454	14.38698	14.53085	14.67616	14.82292	14.97115	15.12087	15.27207	15.42479	15.57904	15.73483	15.89218	16.0511	16.21161	16.37373	16.537467
Buchanan TS	230	1 West	BEACHVILLE	M21	7.096	7.16696	7.23863	7.311016	7.384126	7.457967	7.532547	7.607872	7.683951	7.760791	7.838399	7.916783	7.99595	8.07591	8.156669	8.238236	8.320618	8.403824	8.487862	8.572741	8.658469	8.7450532
Caledonia TS	230	2 West Cei	SIMCOE	M3	13.467	13.60167	13.73769	13.87506	14.01381	14.15395	14.29549	14.43845	14.58283	14.72866	14.87595	15.02471	15.17495	15.3267	15.47997	15.63477	15.79112	15.94903	16.10852	16.2696	16.4323	16.596622
Caledonia TS	230	2 West Cei	SIMCOE	M6	8.4	8.484	8.56884	8.654528	8.741074	8.828484	8.916769	9.005937	9.095996	9.186956	9.278826	9.371614	9.46533	9.559984	9.655583	9.752139	9.849661	9.948157	10.04764	10.14812	10.2496	10.352092
Centralia TS	115	1 West	CLINTON	M1	6.495	6.55995	6.62555	6.691805	6.758723	6.82631	6.894573	6.963519	7.033154	7.103486	7.174521	7.246266	7.318729	7.391916	7.465835	7.540493	7.615898	7.692057	7.768978	7.846668	7.925134	8.0043857
Centralia TS	115	1 West	CLINTON	M2	5.562	5.61762	5.673796	5.730534	5.78784	5.845718	5.904175	5.963217	6.022849	6.083077	6.143908	6.205347	6.267401	6.330075	6.393376	6.457309	6.521882	6.587101	6.652972	6.719502	6.786697	6.854564
Centralia TS	115	1 West	CLINTON	M3	4.775	4.82275	4.870978	4.919687	4.968884	5.018573	5.068759	5.119446	5.170641	5.222347	5.274571	5.327316	5.38059	5.434395	5.488739	5.543627	5.599063	5.655054	5.711604	5.76872	5.826407	5.8846715
Centralia TS	115	1 West	CLINTON	M4	4.234	4.27634	4.319103	4.362294	4.405917	4.449977	4.494476	4.539421	4.584815	4.630663	4.67697	4.72374	4.770977	4.818687	4.866874	4.915543	4.964698	5.014345	5.064488	5.115133	5.166285	5.2179475
Clarke TS	230	1 West	STRATHROY	M2	7.702	7.77902	7.85681	7.935378	8.014732	8.094879	8.175828	8.257586	8.340162	8.423564	8.5078	8.592878	8.678806	8.765594	8.85325	8.941783	9.031201	9.121513	9.212728	9.304855	9.397904	9.4918827
Crosby TS	230	4 East	PERTH	M3	-0.013	-0.01313	-0.01326	-0.01339	-0.01353	-0.01366	-0.0138	-0.01394	-0.01408	-0.01422	-0.01436	-0.0145	-0.01465	-0.0148	-0.01494	-0.01509	-0.01524	-0.0154	-0.01555	-0.01571	-0.01586	-0.0160211
Crosby TS	230	4 East	PERTH	M5	3.121	3.15221	3.183732	3.215569	3.247725	3.280202	3.313004	3.346134	3.379596	3.413392	3.447526	3.482001	3.516821	3.551989	3.587509	3.623384	3.659618	3.696214	3.733176	3.770508	3.808213	3.8462952
Crosby TS	230	4 East	PERTH	M6	3.401	3.43501	3.46936	3.504054	3.539094	3.574485	3.61023	3.646332	3.682796	3.719624	3.75682	3.794388	3.832332	3.870655	3.909362	3.948455	3.98794	4.027819	4.068098	4.108779	4.149866	4.191365
Crowland TS	115	2 West Cei	LINCOLN	M13	5.497	5.55197	5.60749	5.663565	5.7202	5.777402	5.835176	5.893528	5.952463	6.011988	6.072108	6.132829	6.194157	6.256099	6.31866	6.381846	6.445665	6.510121	6.575223	6.640975	6.707385	6.7744585
Crowland TS	115	2 West Cei	LINCOLN	M21	1.544	1.55944	1.575034	1.590785	1.606693	1.62276	1.638987	1.655377	1.671931	1.68865	1.705537	1.722592	1.739818	1.757216	1.774788	1.792536	1.810461	1.828566	1.846852	1.86532	1.883973	1.9028132
Detweiler TS	230	1 West*	LISTOWEL*	M12	8.458	8.54258	8.628006	8.714286	8.801429	8.889443	8.978337	9.068121	9.158802	9.25039	9.342894	9.436323	9.530686	9.625993	9.722253	9.819475	9.91767	10.01685	10.11702	10.21819	10.32037	10.423571

Dundas TS	115	2 West Cei	DUNDAS	M1	4.74	4.7874	4.835274	4.883627	4.932463	4.981788	5.031606	5.081922	5.132741	5.184068	5.235909	5.288268	5.341151	5.394562	5.448508	5.502993	5.558023	5.613603	5.669739	5.726436	5.783701	5.8415378
Dundas TS	115	2 West Cei	DUNDAS	M3	12.999	13.12899	13.26028	13.39288	13.52681	13.66208	13.7987	13.93669	14.07605	14.21681	14.35898	14.50257	14.6476	14.79407	14.94202	15.09144	15.24235	15.39477	15.54872	15.70421	15.86125	16.019863
Dundas TS	115	2 West Cei	DUNDAS	M4	12.958	13.08758	13.21846	13.35064	13.48415	13.61899	13.75518	13.89273	14.03166	14.17197	14.31369	14.45683	14.6014	14.74741	14.89489	15.04384	15.19427	15.34622	15.49968	15.65468	15.81281	15.969335
Dundas TS	115	2 West Cei	DUNDAS	M5	6.488	6.55288	6.618409	6.684593	6.751439	6.818953	6.887143	6.956014	7.025574	7.09583	7.166788	7.238456	7.310841	7.383949	7.457789	7.532367	7.60769	7.683767	7.760605	7.838211	7.916593	7.9957589
Dundas TS	115	2 West Cei	DUNDAS	M6	1.377	1.39077	1.404678	1.418724	1.432912	1.447241	1.461713	1.47633	1.491094	1.506005	1.521065	1.536275	1.551638	1.567154	1.582826	1.598654	1.614641	1.630787	1.647095	1.663566	1.680202	1.6970037
Dundas TS	115	2 West Cei	DUNDAS	M8	4.533	4.57833	4.624113	4.670354	4.717058	4.764229	4.811871	4.85999	4.908589	4.957675	5.007252	5.057325	5.107898	5.158977	5.210567	5.262672	5.315299	5.368452	5.422137	5.476358	5.531121	5.5864327
Dunnville TS	115	2 West Cei	LINCOLN	M2	7.512	7.58712	7.662991	7.739621	7.817017	7.895187	7.974139	8.053881	8.13442	8.215764	8.297921	8.380901	8.46471	8.549357	8.63485	8.721199	8.808411	8.896495	8.98546	9.075314	9.166068	9.2577283
Edgeware TS	230	1 West	AYLMER	M2	9.766	9.86366	9.962297	10.06192	10.16254	10.26416	10.36681	10.47047	10.57518	10.68093	10.78774	10.89562	11.00457	11.11462	11.22577	11.33802	11.4514	11.56592	11.68158	11.79839	11.91638	12.03554
Edgeware TS	230	1 West	AYLMER	M3	5.149	5.20049	5.252495	5.30502	5.35807	5.411651	5.465767	5.520425	5.575629	5.631385	5.687699	5.744576	5.802022	5.860042	5.918643	5.977829	6.037607	6.097984	6.158963	6.220553	6.282759	6.3455861
Edgeware TS	230	1 West	AYLMER	M4	8.986	9.07586	9.166619	9.258285	9.350868	9.444376	9.53882	9.634208	9.73055	9.827856	9.926134	10.0254	10.12565	10.22691	10.32918	10.43247	10.53679	10.64216	10.74858	10.85607	10.96463	11.074274
Elmira TS	115	1 West	LISTOWEL	M2	8.524	8.60924	8.695332	8.782286	8.870109	8.95881	9.048398	9.138882	9.230271	9.322573	9.415799	9.509957	9.605057	9.701107	9.798118	9.896099	9.99506	10.09501	10.19596	10.29792	10.4009	10.504909
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M11	5	5.05	5.1005	5.151505	5.20302	5.25505	5.307601	5.360677	5.414284	5.468426	5.523111	5.578342	5.634125	5.690466	5.747371	5.804845	5.862893	5.921522	5.980737	6.040545	6.10095	6.1619597
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M12	21.985	22.20485	22.4269	22.65117	22.87768	23.10646	23.33752	23.5709	23.8066	24.04467	24.28512	24.52797	24.77325	25.02098	25.27119	25.5239	25.77914	26.03693	26.2973	26.56028	26.82588	27.094137
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M25	6.003	6.06303	6.12366	6.184897	6.246746	6.309213	6.372305	6.436029	6.500389	6.565393	6.631047	6.697357	6.764331	6.831974	6.900294	6.969297	7.03899	7.10938	7.180473	7.252278	7.324801	7.3980488
Fairchild TS	230	2 West Cei	ORANGEVILLE*	M26	9.884	9.98284	10.08267	10.1835	10.28533	10.38818	10.49207	10.59699	10.70296	10.80999	10.91809	11.02727	11.13754	11.24891	11.3614	11.47502	11.58977	11.70566	11.82272	11.94095	12.06036	12.180962
Finch TS	230	2 West Cei	ORANGEVILLE*	M11	4.118	4.15918	4.200772	4.24278	4.285207	4.328059	4.37134	4.415053	4.459204	4.503796	4.548834	4.594322	4.640265	4.686668	4.733535	4.78087	4.828679	4.876966	4.925735	4.974993	5.024743	5.07499
Finch TS	230	2 West Cei	ORANGEVILLE*	M12	11.789	11.90689	12.02596	12.14622	12.26768	12.39036	12.51426	12.6394	12.7658	12.89346	13.02239	13.15261	13.28414	13.41698	13.55115	13.68666	13.82353	13.96176	14.10138	14.2424	14.38482	14.528669
Galt TS	230	2 West Cei	DUNDAS	M12	8.628	8.71428	8.801423	8.889437	8.978331	9.068115	9.158796	9.250384	9.342888	9.436317	9.53068	9.625986	9.722246	9.819469	9.917664	10.01684	10.11701	10.21818	10.32036	10.42356	10.5278	10.633078
Goderich TS	115	1 West	CLINTON	M1	3.807	3.84507	3.883521	3.922356	3.961579	4.001195	4.041207	4.081619	4.122435	4.16366	4.205296	4.247349	4.289823	4.332721	4.376048	4.419809	4.464007	4.508647	4.553733	4.599271	4.645263	4.6917161
Goderich TS	115	1 West	CLINTON	M2	5.249	5.30149	5.354505	5.40805	5.46213	5.516752	5.571919	5.627638	5.683915	5.740754	5.798162	5.856143	5.914705	5.973852	6.03359	6.093926	6.154865	6.216414	6.278578	6.341364	6.404778	6.4688253
Halton TS	230	2 West Cei	DUNDAS*	M21	10.62	10.7262	10.83346	10.9418	11.05121	11.16173	11.27334	11.38608	11.49994	11.61494	11.73109	11.8484	11.96688	12.08655	12.20742	12.32949	12.45279	12.57731	12.70309	12.83012	12.95842	13.088002
Highbury TS	115	1 West	BEACHVILLE	M11	4.05	4.0905	4.131405	4.172719	4.214446	4.256591	4.299157	4.342148	4.38557	4.429425	4.47372	4.518457	4.563641	4.609278	4.655371	4.701924	4.748944	4.796433	4.844397	4.892841	4.94177	4.9911874
Ingersoll TS	230	1 West	BEACHVILLE	M43	13.906	14.04506	14.18551	14.32737	14.47064	14.61535	14.7615	14.90911	15.05821	15.20879	15.36088	15.51448	15.66963	15.82633	15.98459	16.14443	16.30588	16.46894	16.63363	16.79996	16.96796	17.137642
Ingersoll TS	230	1 West	BEACHVILLE	M44	2.403	2.42703	2.4513	2.475813	2.500571	2.525577	2.550833	2.576341	2.602105	2.628126	2.654407	2.680951	2.707761	2.734838	2.762187	2.789808	2.817706	2.845884	2.874342	2.903086	2.932117	2.9614378
Ingersoll TS	230	1 West	BEACHVILLE	M45	6.498	6.56298	6.62861	6.694896	6.761845	6.829463	6.897758	6.966736	7.036403	7.106767	7.177835	7.249613	7.322109	7.39533	7.469283	7.543976	7.619416	7.69561	7.772566	7.850292	7.928795	8.0080828
Ingersoll TS	230	1 West	BEACHVILLE	M46	7.651	7.72751	7.804785	7.882833	7.961661	8.041278	8.121691	8.202908	8.284937	8.367786	8.451464	8.535979	8.621338	8.707552	8.794627	8.882573	8.971399	9.061113	9.151724	9.243242	9.335674	9.4290307
Ingersoll TS	230	1 West	BEACHVILLE	M49	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Ingersoll TS	230	1 West	BEACHVILLE	M50	7.153	7.22453	7.296775	7.369743	7.44344	7.517875	7.593054	7.668984	7.745674	7.823131	7.901362	7.980376	8.060179	8.140781	8.222189	8.304411	8.387455	8.47133	8.556043	8.641603	8.728019	8.8152995
Ingersoll TS	230	1 West	BEACHVILLE	M51	10.189	10.29089	10.3938	10.49774	10.60271	10.70874	10.81583	10.92399	11.03323	11.14356	11.25499	11.36754	11.48122	11.59603	11.71199	11.82911	11.9474	12.06688	12.18755	12.30942	12.43252	12.556841
Ingersoll TS	230	1 West	BEACHVILLE	M52	10.363	10.46663	10.5713	10.67701	10.78378	10.89162	11.00053	11.11054	11.22164	11.33386	11.4472	11.56167	11.67729	11.79406	11.912	12.03112	12.15143	12.27295	12.39568	12.51963	12.64483	12.771278
Jarvis TS	230	2 West Cei	SIMCOE	M2	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Jarvis TS	230	2 West Cei	SIMCOE	M3	5.835	5.89335	5.952284	6.011806	6.071924	6.132644	6.19397	6.25591	6.318469	6.381654	6.44547	6.509925	6.575024	6.640774	6.707182	6.774254	6.841996	6.910416	6.979521	7.049316	7.119809	7.191007
Jarvis TS	230	2 West Cei	SIMCOE	M4	8.114	8.19514	8.277091	8.359862	8.443461	8.527896	8.613175	8.699306	8.786299	8.874162	8.962904	9.052533	9.143058	9.234489	9.326834	9.420102	9.514303	9.609446	9.705541	9.802596	9.900622	9.9996282
Jarvis TS	230	2 West Cei	SIMCOE	M7	0.034	0.03434	0.034683	0.03503	0.035381	0.035734	0.036092	0.036453	0.036817	0.037185	0.037557	0.037933	0.038312	0.038695	0.039082	0.039473	0.039868	0.040266	0.040669	0.041076	0.041486	0.0419013
Keith TS	230	1 West	ESSEX	M3	5.892	5.95092	6.010429	6.070533	6.131239	6.192551	6.254477	6.317021	6.380192	6.443994	6.508434	6.573518	6.639253	6.705646	6.772702	6.840429	6.908833	6.977922	7.047701	7.118178	7.18936	7.2612533
Keith TS	230	1 West	ESSEX	M4	7.191	7.26291	7.335539	7.408894	7.482983	7.557813	7.633391	7.709725	7.786823	7.864691	7.943338	8.022771	8.102999	8.184029	8.265869	8.348528	8.432013	8.516333	8.601496	8.687511	8.774387	8.8621304
Keith TS	230	1 West	ESSEX	M5	5.44	5.4944	5.549344	5.604837	5.660886	5.717495	5.77467	5.832416	5.89074	5.949648	6.009144	6.069236	6.129928	6.191227	6.25314	6.315671	6.378828	6.442616	6.507042	6.572113	6.637834	6.7042122
Kent TS	230	1 West	KENT	M1	10.512	10.61712	10.72329	10.83052	10.93883	11.04822	11.1587	11.27029	11.38299	11.49682	11.61179	11.72791	11.84518	11.96364	12.08327	12.20411	12.32615	12.44941	12.5739	12.69964	12.82664	12.954904
Kent TS	230	1 West	KENT	M15	11.961	12.08061	12.20142	12.32343	12.44666	12.57113	12.69684	12.82381	12.95205	13.08157	13.21239	13.34451	13.47795	13.61273	13.74886	13.88635	14.02521	14.16547	14.30712	14.45019	14.59469	14.74064
Kent TS	230	1 West	KENT	M16	12.532	12.65732	12.78389	12.91173	13.04085	13.17126	13.30297	13.436	13.57036	13.70606	13.84312	13.98156	14.12137	14.26258	14.40521	14.54926	14.69476	14.8417	14.99012	15.14002	15.29142	15.444336
Kent TS	230	1 West	KENT	M17	11.573	11.68873	11.80562	11.92367	12.04291	12.16334	12.28497	12.40782	12.5319	12.65722	12.78379	12.91163	13.04075	13.17115	13.30287	13.43589	13.57025	13.70596	13.84301	13.98144	14.12126	14.262472
Kent TS	230	1 West	KENT	M18	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Kent TS	230	1 West	KENT	M2	7.3	7.373	7.44673	7.521197	7.596409	7.672373	7.749097	7.826588	7.904854	7.983902	8.063742	8.144379	8.225823	8.308081	8.391162	8.475073	8.559824	8.645422	8.731877	8.819195	8.907387	8.9964612
Kingsville TS	115	1 West	ESSEX	M1	6.571	6.63671	6.703077	6.770108	6.837809	6.906187	6.975249	7.045001	7.115451	7.186606	7.258472	7.331057	7.404367	7.478411	7.553195	7.628727	7.705014	7.782064	7.859885	7.938484	8.017869	8.0980474
Kingsville TS	115	1 West	ESSEX	M2	9.362	9.45562	9.550176	9.645678	9.742135	9.839556	9.937952	10.03733	10.1377	10.23908	10.34147	10.44489	10.54934	10.65483	10.76138	10.86899	10.97768	11.08746	11.19833	11.31032	11.42342	11.537653
Kingsville TS	115	1 West	ESSEX	M3	8.513	8.59813	8.684111	8.770952	8.858662	8.947249	9.036721	9.127088	9.218359	9.310543	9.403648	9.497685	9.592661	9.688588	9.785474	9.883329	9.982162	10.08198	10.1828	10.28463	10.38748	10.491353
Kingsville TS	115	1 West	ESSEX	M4	6.982	7.05182	7.122338	7.193562	7.265497	7.338152	7.411534	7.485649	7.560506	7.636111	7.712472	7.789596	7.867492	7.946167	8.025629	8.105885	8.186944	8.268814	8.351502	8.435017	8.519367	8.6045605
Kingsville TS	115	1 West	ESSEX	M5	9.293	9.38593	9.479789	9.574587	9.670333	9.767036	9.864707	9.963354	10.06299	10.16362	10.26525	10.36791	10.47159	10.5763	10.68206	10.78888	10.89677	11.00574	11.1158	11.22696	11.33923	11.452618
Kingsville TS	115	1 West	ESSEX	M6	11.694	11.81094	11.92905	12.04834	12.16882	12.29051	12.41342	12.53755	12.66293	12.78956	12.91745	13.04663	13.17709	13.30886	13.44195	13.57637	13.71213	13.84926	13.98775	14.12763	14.2689	14.411591
Kingsville TS	115	1 West	ESSEX	M7	7.656	7.73256	7.809886	7.887984	7.966864	8.046533	8.126998	8.208268	8.290351	8.373254	8.456987	8.541557	8.626972	8.713242	8.800375	8.888378	8.977262	9.067035	9.157705	9.249282	9.341775	9.4351927
Kingsville TS	115	1 West	ESSEX	M8	9.325	9.41825	9.512433	9.607557	9.703632	9.800669	9.898675	9.997662	10.09764	10.19862	10.3006	10.40361	10.50764	10.61272	10.71885	10.82604	10.9343	11.04364	11.15408	11.26562	11.37827	11.492055
Kingsville TS	115	1 West	ESSEX	M9	9.44	9.5344	9.629744	9.726041	9.823302	9.921535	10.02075	10.12096	10.22217	10.32439	10.42763	10.53191	10.63723	10.7436	10.85104	10.95955	11.06914	11.17983	11.29163	11.40455	11.51859	11.63378
Kleinburg TS	230	3A Central	NEWMARKET	M5	8.649	8.73549	8.822845	8.911073	9.000184	9.090186	9.181088	9.272899	9.365628	9.459284	9.553877	9.649416	9.74591	9.843369	9.941802	10.04122	10.14163	10.24305	10.34548	10.44893	10.55342	10.658958
Kleinburg TS	230	3A Central	NEWMARKET	M6	10.793	10.90093	11.00994	11.12004	11.23124	11.34355	11.45699	11.57156	11.68727	11.80415	11.92219	12.04141	12.16182	12.28344	12.40628	12.53034	12.65564	12.7822	12.91002	13.03912	13.16951	13.301206
Lake TS	230	2 West Cei	LINCOLN*	M1	7	7.07	7.1407	7.212107	7.284228	7.35707	7.430641	7.504947	7.579997	7.655797	7.732355	7.809678	7.887775	7.966653	8.046319	8.126783	8.208051	8.290131	8.373032	8.456763	8.54133	8.6267436
Lake TS	230	2 West Cei	LINCOLN*	M2	7.941	8.02041	8.100614	8.18162	8.263436	8.346071	8.429532	8.513827	8.598965	8.684955	8.771804	8.859522	8.948118	9.037599	9.127975	9.219254	9.311447	9.404561	9.498607	9.593593	9.689529	9.7864244
Lake TS	230	2 West Cei	LINCOLN*	M3	7.67	7.7467	7.824167	7.902409	7.981433	8.061247	8.14186	8.223278	8.305511	8.388566	8.472452	8.557176	8.642748	8.729175	8.816467	8.904632	8.993678	9.083615	9.174451	9.266196	9.358858	9.4524462
Lake TS	230	2 West Cei	LINCOLN*	M4	7.517	7.59217	7.668092	7.744773	7.82222	7.900443	7.979447	8.059241	8.139834	8.221232	8.303445	8.386479	8.470344	8.555047	8.640598	8.727004	8.814274	8.902416	8.991441	9.081355	9.172169	9.2638902
Lake TS	230	2 West Cei	LINCOLN*	M5	7.426	7.50026	7.575263	7.651015	7.727525	7.804801	7.882849	7.961677	8.041294	8.121707	8.202924	8.284953	8.367803	8.451481	8.535996	8.621355	8.707569	8.794645	8.882591	8.971417	9.061131	9.1517425
Lake TS	230	2 West Cei	LINCOLN*	M6	8.009	8.08909	8.169981	8.251681	8.334198	8.417539	8.501715	8.586732	8.672599	8.759325	8.846919	8.935388	9.024742	9.114989	9.206139	9.2982	9.391182	9.485094	9.579945	9.675745	9.772502	9.8702271
Lambton TS	230	1 West	LAMBTON	M1	3.839	3.87739	3.916164	3.955326	3.994879	4.034828	4.075176	4.115928	4.157087	4.198658	4.240644	4.283051	4.325881	4.36914	4.412832	4.45696	4.501529	4.546545	4.59201	4.63793	4.68431	4.7311527
Lambton TS	230	1 West	LAMBTON	M2	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Lambton TS	230	1 West	LAMBTON	M3	4.965	5.01465	5.064797	5.115444	5.166599	5.218265	5.270448	5.323152	5.376384	5.430147	5.484449	5.539293	5.594686	5.650633	5.707139	5.764211	5.821853	5.880072	5.938872	5.998261	6.058244	6.118826
Lambton TS	230	1 West	LAMBTON	M4	15.996	16.15596	16.31752	16.48069	16.6455	16.81196	16.98008	17.14988	17.32138	17.49459	17.66954	17.84623	18.02469	18.20494	18.38699	18.57086	18.75657	18.94413	19.13358	19.32491	19.51816	19.713341
Lambton TS	230	1 West	LAMBTON	M5	10.627	10.73327	10.8406	10.94901	11.0585	11.16908	11.28077	11.39358	11.50752	11.62259	11.73882	11.85621	11.97477	12.09452	12.21546	12.33762	12.46099	12.5856	12.71146	12.83857	12.96696	13.096629
Lambton TS	230	1 West	LAMBTON	M6	3	3.03	3.0603	3.090903	3.121812	3.15303	3.18456	3.216406	3.24857	3.281056	3.313866	3.347005	3.380475	3.41428	3.448423	3.482907	3.517736	3.552913	3.588442	3.624327	3.66057	3.6971758
Lauzon TS	230	1 West	ESSEX	M23	7.519	7.59419	7.670132	7.746833	7.824302	7.902545	7.98157	8.061386	8.142	8.22342	8.305654	8.38871	8.472597	8.557323	8.642897	8.729326	8.816619	8.904785	8.993833	9.083771	9.174609	9.266355

Lauzon TS	230	1 West	ESSEX	M24	12.257	12.37957	12.50337	12.6284	12.75468	12.88223	13.01105	13.14116	13.27257	13.4053	13.53935	13.67475	13.81149	13.94961	14.08911	14.23	14.3723	14.51602	14.66118	14.80779	14.95587	15.105428
Lauzon TS	230	1 West	ESSEX	M25	5.653	5.70953	5.766625	5.824292	5.882534	5.94136	6.000773	6.060781	6.121389	6.182603	6.244429	6.306873	6.369942	6.433641	6.497978	6.562958	6.628587	6.694873	6.761822	6.82944	6.897734	6.9667116
Lauzon TS	230	1 West	ESSEX	M26	11.403	11.51703	11.6322	11.74852	11.86601	11.98467	12.10451	12.22556	12.34782	12.47129	12.59601	12.72197	12.84919	12.97768	13.10745	13.23853	13.37091	13.50462	13.63967	13.77607	13.91383	14.052965
Lauzon TS	230	1 West	ESSEX	M27	8.963	9.05263	9.143156	9.234588	9.326934	9.420203	9.514405	9.609549	9.705645	9.802701	9.900728	9.999735	10.09973	10.20073	10.30274	10.40576	10.50982	10.61492	10.72107	10.82828	10.93656	11.045929
Lauzon TS	230	1 West	ESSEX	M28	5.653	5.70953	5.766625	5.824292	5.882534	5.94136	6.000773	6.060781	6.121389	6.182603	6.244429	6.306873	6.369942	6.433641	6.497978	6.562958	6.628587	6.694873	6.761822	6.82944	6.897734	6.9667116
Lauzon TS	230	1 West	ESSEX	M29	6.789	6.85689	6.925459	6.994713	7.064661	7.135307	7.20666	7.278727	7.351514	7.425029	7.49928	7.574272	7.650015	7.726515	7.80378	7.881818	7.960636	8.040243	8.120645	8.201852	8.28387	8.3667089
Lauzon TS	230	1 West	ESSEX	M4	5.498	5.55298	5.60851	5.664595	5.721241	5.778453	5.836238	5.8946	5.953546	6.013082	6.073212	6.133945	6.195284	6.257237	6.319809	6.383007	6.446837	6.511306	6.576419	6.642183	6.708605	6.7756909
Leslie TS	230	3A Central	NEWMARKET*	M2	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Leslie TS	230	3A Central	NEWMARKET*	M31	11.46	11.5746	11.69035	11.80725	11.92532	12.04458	12.16502	12.28667	12.40954	12.53363	12.65897	12.78556	12.91341	13.04255	13.17297	13.3047	13.43775	13.57213	13.70785	13.84493	13.98338	14.123212
Longwood TS	500	1 West	STRATHROY	M23	5.886	5.94486	6.004309	6.064352	6.124995	6.186245	6.248108	6.310589	6.373695	6.437432	6.501806	6.566824	6.632492	6.698817	6.765805	6.833463	6.901798	6.970816	7.040524	7.110929	7.182039	7.253859
Longwood TS	500	1 West	STRATHROY	M24	6.335	6.39835	6.462334	6.526957	6.592226	6.658149	6.72473	6.791977	6.859897	6.928496	6.997781	7.067759	7.138437	7.209821	7.281919	7.354738	7.428286	7.502569	7.577594	7.65337	7.729904	7.8072029
Longwood TS	500	1 West	STRATHROY	M25	5.232	5.28432	5.337163	5.390535	5.44444	5.498885	5.553873	5.609412	5.665506	5.722161	5.779383	5.837177	5.895549	5.954504	6.014049	6.07419	6.134931	6.196281	6.258244	6.320826	6.384034	6.4478746
Longwood TS	500	1 West	STRATHROY	M26	2.001	2.02101	2.04122	2.061632	2.082249	2.103071	2.124102	2.145343	2.166796	2.188464	2.210349	2.232452	2.254777	2.277325	2.300098	2.323099	2.34633	2.369793	2.393491	2.417426	2.4416	2.4660163
Malden TS	230	1 West	ESSEX	M10	8.72	8.8072	8.895272	8.984225	9.074067	9.164808	9.256456	9.34902	9.44251	9.536936	9.632305	9.728628	9.825914	9.924173	10.02342	10.12365	10.22489	10.32713	10.43041	10.53471	10.64006	10.746458
Malden TS	230	1 West	ESSEX	M11	8.278	8.36078	8.444388	8.528832	8.61412	8.700261	8.787264	8.875136	8.963888	9.053527	9.144062	9.235503	9.327858	9.421136	9.515348	9.610501	9.706606	9.803672	9.901709	10.00073	10.10073	10.20174
Malden TS	230	1 West	ESSEX	M12	4.103	4.14403	4.18547	4.227325	4.269598	4.312294	4.355417	4.398971	4.442961	4.487391	4.532265	4.577587	4.623363	4.669597	4.716293	4.763456	4.81109	4.859201	4.907793	4.956871	5.00644	5.0565041
Malden TS	230	1 West	ESSEX	M7	6.488	6.55288	6.618409	6.684593	6.751439	6.818953	6.887143	6.956014	7.025574	7.09583	7.166788	7.238456	7.310841	7.383949	7.457789	7.532367	7.60769	7.683767	7.760605	7.838211	7.916593	7.9957589
Malden TS	230	1 West	ESSEX	M8	5.65	5.7065	5.763565	5.821201	5.879413	5.938207	5.997589	6.057565	6.11814	6.179322	6.241115	6.303526	6.366561	6.430227	6.494529	6.559475	6.625069	6.69132	6.758233	6.825816	6.894074	6.9630145
Malden TS	230	1 West	ESSEX	M9	8.132	8.21332	8.295453	8.378408	8.462192	8.546814	8.632282	8.718605	8.805791	8.893849	8.982787	9.072615	9.163341	9.254975	9.347524	9.441	9.53541	9.630764	9.727071	9.824342	9.922585	10.021811
Malvern TS	230	3A Central	NEWMARKET*	M35	5.645	5.70145	5.758465	5.816049	5.87421	5.932952	5.992281	6.052204	6.112726	6.173853	6.235592	6.297948	6.360927	6.424537	6.488782	6.55367	6.619206	6.685399	6.752253	6.819775	6.887973	6.9568525
Modeland TS	230	1 West	LAMBTON	M25	12.7	12.827	12.95527	13.08482	13.21567	13.34783	13.48131	13.61612	13.75228	13.8898	14.0287	14.16899	14.31068	14.45378	14.59832	14.74431	14.89175	15.04067	15.19107	15.34298	15.49641	15.651378
Nebo TS	230	2 West Cer	DUNDAS	M3	6.877	6.94577	7.015228	7.08538	7.156234	7.227796	7.300074	7.373075	7.446806	7.521274	7.596486	7.672451	7.749176	7.826667	7.904934	7.983984	8.063823	8.144462	8.225906	8.308165	8.391247	8.4751594
Nebo TS	230	2 West Cer	DUNDAS	M4	11.203	11.31503	11.42818	11.54246	11.65789	11.77447	11.89221	12.01113	12.13124	12.25256	12.37508	12.49883	12.62382	12.75006	12.87756	13.00634	13.1364	13.26776	13.40044	13.53444	13.66979	13.806487
Nebo TS	230	2 West Cer	DUNDAS	M5	5.194	5.24594	5.298399	5.351383	5.404897	5.458946	5.513536	5.568671	5.624358	5.680601	5.737407	5.794781	5.852729	5.911256	5.970369	6.030073	6.090373	6.151277	6.21279	6.274918	6.337667	6.4010437
Nebo TS	230	2 West Cer	DUNDAS	M6	9.19	9.2819	9.374719	9.468466	9.563151	9.658782	9.75537	9.852924	9.951453	10.05097	10.15148	10.25299	10.35552	10.45908	10.56367	10.6693	10.776	10.88376	10.9926	11.10252	11.21355	11.325682
Nebo TS	230	2 West Cer	DUNDAS	M7	11.152	11.26352	11.37616	11.48992	11.60482	11.72086	11.83807	11.95645	12.07602	12.19678	12.31875	12.44193	12.56635	12.69202	12.81894	12.94713	13.0766	13.20736	13.33944	13.47283	13.60756	13.743635
Nebo TS	230	2 West Cer	DUNDAS	M8	8	8.08	8.1608	8.242408	8.324832	8.40808	8.492161	8.577083	8.662854	8.749482	8.836977	8.925347	9.0146	9.104746	9.195794	9.287752	9.380629	9.474435	9.56918	9.664872	9.76152	9.8591355
Norfolk TS	115	2 West Cer	SIMCOE	M1	8.258	8.34058	8.423986	8.508226	8.593308	8.679241	8.766033	8.853694	8.942231	9.031653	9.12197	9.213189	9.305321	9.398374	9.492358	9.587282	9.683154	9.779986	9.877786	9.976564	10.07633	10.177093
Norfolk TS	115	2 West Cer	SIMCOE	M3	6.743	6.81043	6.878534	6.94732	7.016793	7.086961	7.15783	7.229409	7.301703	7.37472	7.448467	7.522952	7.598181	7.674163	7.750905	7.828414	7.906698	7.985765	8.065622	8.146279	8.227741	8.3100189
Norfolk TS	115	2 West Cer	SIMCOE	M4	2.387	2.41087	2.434979	2.459328	2.483922	2.508761	2.533849	2.559187	2.584779	2.610627	2.636733	2.6631	2.689731	2.716629	2.743795	2.771233	2.798945	2.826935	2.855204	2.883756	2.912594	2.9417196
Norfolk TS	115	2 West Cer	SIMCOE	M6	7.277	7.34977	7.423268	7.4975	7.572475	7.6482	7.724682	7.801929	7.879948	7.958748	8.038335	8.118719	8.199906	8.281905	8.364724	8.448371	8.532855	8.618183	8.704365	8.791409	8.879323	8.9681161
Oakville TS #2	230	2 West Cer	DUNDAS*	M45	17.074	17.24474	17.41719	17.59136	17.76727	17.94495	18.1244	18.30564	18.4887	18.67358	18.86032	19.04892	19.23941	19.4318	19.62612	19.82238	20.02061	20.22081	20.42302	20.62725	20.83352	21.04186
Oakville TS #2	230	2 West Cer	DUNDAS*	M46	19.648	19.84448	20.04292	20.24335	20.44579	20.65025	20.85675	21.06532	21.27597	21.48873	21.70362	21.92065	22.13986	22.36126	22.58487	22.81072	23.03883	23.26921	23.50191	23.73692	23.97429	24.214037
Oakville TS #2	230	2 West Cer	DUNDAS*	M47	11.649	11.76549	11.88314	12.00198	12.122	12.24322	12.36565	12.4893	12.6142	12.74034	12.86774	12.99642	13.12638	13.25765	13.39023	13.52413	13.65937	13.79596	13.93392	14.07326	14.21399	14.356134
Oakville TS #2	230	2 West Cer	DUNDAS*	M48	0.418	0.42218	0.426402	0.430666	0.434972	0.439322	0.443715	0.448153	0.452634	0.45716	0.461732	0.466349	0.471013	0.475723	0.48048	0.485285	0.490138	0.495039	0.49999	0.50499	0.510039	0.5151398
Orangeville TS	230	2 West Cer	ORANGEVILLE	M25	8.883	8.97183	9.061548	9.152164	9.243685	9.336122	9.429483	9.523778	9.619016	9.715206	9.812358	9.910482	10.00959	10.10968	10.21078	10.31289	10.41602	10.52018	10.62538	10.73163	10.83895	10.947338
Orangeville TS	230	2 West Cer	ORANGEVILLE	M26	9.569	9.66469	9.761337	9.85895	9.95754	10.05712	10.15769	10.25926	10.36186	10.46547	10.57013	10.67583	10.78259	10.89041	10.99932	11.10931	11.22041	11.33261	11.44594	11.56039	11.676	11.792758
Palermo TS	230	2 West Cer	DUNDAS*	M1	9.301	9.39401	9.48795	9.58283	9.678658	9.775444	9.873199	9.971931	10.07165	10.17237	10.27409	10.37683	10.4806	10.58541	10.69126	10.79817	10.90615	11.01522	11.12537	11.23662	11.34899	11.462477
Palermo TS	230	2 West Cer	DUNDAS*	M3	3.472	3.50672	3.541787	3.577205	3.612977	3.649107	3.685598	3.722454	3.759678	3.797275	3.835248	3.8736	3.912337	3.95146	3.990974	4.030884	4.071193	4.111905	4.153024	4.194554	4.2365	4.2788648
Port Colborne TS	115	2 West Cer	LINCOLN	M11	12.551	12.67651	12.80328	12.93131	13.06062	13.19123	13.32314	13.45637	13.59093	13.72684	13.86411	14.00275	14.14278	14.28421	14.42705	14.57132	14.71703	14.8642	15.01285	15.16298	15.31461	15.467751
Ramore TS	115	6 Northeas	KIRKLAND LAKE	M3	1.513	1.52813	1.543411	1.558845	1.574434	1.590178	1.60608	1.622141	1.638362	1.654746	1.671293	1.688006	1.704886	1.721935	1.739154	1.756546	1.774111	1.791853	1.809771	1.827869	1.846148	1.864609
Ramore TS	115	6 Northeas	KIRKLAND LAKE	M5	2.017	2.03717	2.057542	2.078117	2.098898	2.119887	2.141086	2.162497	2.184122	2.205963	2.228023	2.250303	2.272806	2.295534	2.318489	2.341674	2.365091	2.388742	2.412629	2.436756	2.461123	2.4857345
Richview TS	230	2 West Cer	ORANGEVILLE*	M4	9.912	10.01112	10.11123	10.21234	10.31447	10.41761	10.52179	10.62701	10.73328	10.84061	10.94901	11.0585	11.16909	11.28078	11.39359	11.50752	11.6226	11.73883	11.85621	11.97478	12.09452	12.215469
Richview TS	230	2 West Cer	ORANGEVILLE*	M47	11.451	11.56551	11.68117	11.79798	11.91596	12.03512	12.15547	12.27702	12.39979	12.52379	12.64903	12.77552	12.90327	13.03231	13.16263	13.29426	13.4272	13.56147	13.69708	13.83406	13.9724	14.11212
Richview TS	230	2 West Cer	ORANGEVILLE*	M5	4.095	4.13595	4.17731	4.219083	4.261273	4.303886	4.346925	4.390394	4.434298	4.478641	4.523428	4.568662	4.614348	4.660492	4.707097	4.754168	4.80171	4.849727	4.898224	4.947206	4.996678	5.046645
Richview TS	230	2 West Cer	ORANGEVILLE*	M7	2.974	3.00374	3.033777	3.064115	3.094756	3.125704	3.156961	3.188531	3.220416	3.25262	3.285146	3.317998	3.351178	3.384689	3.418536	3.452722	3.487249	3.522121	3.557343	3.592916	3.628845	3.6651336
Seaforth TS	230	1 West	CLINTON	M2	10.141	10.24241	10.34483	10.44828	10.55277	10.65829	10.76488	10.87252	10.98125	11.09106	11.20197	11.31399	11.42713	11.5414	11.65682	11.77339	11.89112	12.01003	12.13013	12.25143	12.37395	12.497687
Seaforth TS	230	1 West	CLINTON	M3	3.515	3.55015	3.585652	3.621508	3.657723	3.6943	3.731243	3.768556	3.806241	3.844304	3.882747	3.921574	3.96079	4.000398	4.040402	4.080806	4.121614	4.16283	4.204458	4.246503	4.288968	4.3318577
Seaforth TS	230	1 West	CLINTON	M4	6.178	6.23978	6.302178	6.3652	6.428852	6.49314	6.558071	6.623652	6.689889	6.756788	6.824355	6.892599	6.961525	7.03114	7.101452	7.172466	7.244191	7.316633	7.389799	7.463697	7.538334	7.6137174
Seaforth TS	230	1 West	CLINTON	M5	4.159	4.20059	4.242596	4.285022	4.327872	4.371151	4.414862	4.459011	4.503601	4.548637	4.594123	4.640065	4.686465	4.73333	4.780663	4.82847	4.876755	4.925522	4.974777	5.024525	5.07477	5.1255181
Sheppard TS	230	3A Central	BOWMANVILLE*	M2	9.346	9.43946	9.533855	9.629193	9.725485	9.82274	9.920967	10.02018	10.12038	10.22158	10.3238	10.42704	10.53131	10.63662	10.74299	10.85042	10.95892	11.06851	11.17919	11.29099	11.4039	11.517935
Sheppard TS	230	3A Central	BOWMANVILLE*	M4	7.469	7.54369	7.619127	7.695318	7.772271	7.849994	7.928494	8.007779	8.087857	8.168735	8.250423	8.332927	8.416256	8.500419	8.585423	8.671277	8.75799	8.84557	8.934025	9.023366	9.113599	9.2047354
St.Thomas TS	115	1 West	AYLMER	M10	10.596	10.70196	10.80898	10.91707	11.02624	11.1365	11.24787	11.36035	11.47395	11.58869	11.70458	11.82162	11.93984	12.05924	12.17983	12.30163	12.42464	12.54889	12.67438	12.80112	12.92913	13.058425
St.Thomas TS	115	1 West	AYLMER	M11	0.034	0.03434	0.034683	0.03503	0.035381	0.035734	0.036092	0.036453	0.036817	0.037185	0.037557	0.037933	0.038312	0.038695	0.039082	0.039473	0.039868	0.040266	0.040669	0.041076	0.041486	0.0419013
Stratford TS	230	1 West	BEACHVILLE	M1	4.475	4.51975	4.564948	4.610597	4.656703	4.70327	4.750303	4.797806	4.845784	4.894242	4.943184	4.992616	5.042542	5.092967	5.143897	5.195336	5.247289	5.299762	5.35276	5.406288	5.46035	5.5149539
Stratford TS	230	1 West	BEACHVILLE	M6	10.984	11.09384	11.20478	11.31683	11.42999	11.54429	11.65974	11.77633	11.8941	12.01304	12.13317	12.2545	12.37705	12.50082	12.62582	12.75208	12.8796	13.0084	13.13848	13.26987	13.40257	13.536593
Stratford TS	230	1 West	BEACHVILLE	M7	11	11.11	11.2211	11.33331	11.44664	11.56111	11.67672	11.79349	11.91142	12.03054	12.15084	12.27235	12.39508	12.51903	12.64422	12.77066	12.89837	13.02735	13.15762	13.2892	13.42209	13.556311
Strathroy TS	115	1 West	STRATHROY	M1	10.866	10.97466	11.08441	11.19525	11.3072	11.42028	11.53448	11.64982	11.76632	11.88398	12.00282	12.12285	12.24408	12.36652	12.49019	12.61509	12.74124	12.86865	12.99734	13.12731	13.25858	13.391171
Strathroy TS	115	1 West	STRATHROY	M3	11	11.11	11.2211	11.33331	11.44664	11.56111	11.67672	11.79349	11.91142	12.03054	12.15084	12.27235	12.39508	12.51903	12.64422	12.77066	12.89837	13.02735	13.15762	13.2892	13.42209	13.556311
Tillsonburg TS	115	1 West	AYLMER	M1	7.486	7.56086	7.636469	7.712833	7.789962	7.867861	7.94654	8.026005	8.106265	8.187328	8.269201	8.351893	8.435412	8.519766	8.604964	8.691014	8.777924	8.865703	8.95436	9.043904	9.134343	9.2256861
Tillsonburg TS	115	1 West	AYLMER	M10	6.588	6.65388	6.720419	6.787623	6.855499	6.924054	6.993295	7.063228	7.13386	7.205199	7.277251	7.350023	7.423523	7.497759	7.572736	7.648463	7.724948	7.802198	7.88022	7.959022	8.038612	8.1189981
Tillsonburg TS	115	1 West	AYLMER	M2	8.367	8.45067	8.535177	8.620528	8.706734	8.793801	8.881739	8.970556	9.060262	9.150865	9.242373	9.334797	9.428145	9.522426	9.617651	9.713827	9.810966	9.909075	10.00817	10.10825	10.20933	10.311423
Tillsonburg TS	115	1 West	AYLMER	M3	13.467	13.60167	13.73769	13.87506	14.01381	14.15395	14.29549	14.43845	14.58283	14.72866	14.87595	15.02471	15.17495	15.3267	15.47997	15.63477	15.79112	15.94903	16.10852	16.2696	16.4323	16.596622
Tillsonburg TS	115	1 West	AYLMER	M4	10.36	10.4636	10.56824	10.67392	10.78066	10.88846	10.99735	11.10732	11.2184	11.33058	11.44389	11.55832	11.67391	11.79065	11.90855	12.02764	12.14791	12.26939	12.39209	12.51601	12.64117	12.767581
Timmins TS	115	6 Northeas	TIMMINS	M10	8.302	8.38502	8.46887	8.553559	8.639094	8.725485	8.81274	8.900868	8.989876	9.079775	9.170573	9.262279	9.354901	9.44845	9.542935	9.638364	9.734748	9.832095	9.930416	10.02972	10.13002	10.231318
Timmins TS	115	6 Northeas	TIMMINS	M11	0.42	0.4242	0.428442	0.432726	0.437054	0.441424	0.445838	0.450297	0.4548	0.459348	0.463941	0.468581	0.473267	0.477999	0.482779	0.487607	0.492483	0.497408	0.502382	0.507406	0.51248	0.5176046
Timmins TS	115	6 Northeas	TIMMINS	M5	8.15	8.2315	8.313815	8.396953	8.480923	8.565732	8.651389	8.737903	8.825282	8.913535	9.00267	9.092697	9.183624	9.27546	9.368215	9.461897	9.556516	9.652081	9.748602	9.846088	9.944549	10.043994

Timmins TS	115	6 Northeas	TIMMINS	M6	5.244	5.29644	5.349404	5.402898	5.456927	5.511497	5.566612	5.622278	5.678501	5.735286	5.792638	5.850565	5.90907	5.968161	6.027843	6.088121	6.149002	6.210492	6.272597	6.335323	6.398677	6.4626633
Timmins TS	115	6 Northeas	TIMMINS	M7	12.79	12.9179	13.04708	13.17755	13.30933	13.44242	13.57684	13.71261	13.84974	13.98823	14.12812	14.2694	14.41209	14.55621	14.70178	14.84879	14.99728	15.14725	15.29873	15.45171	15.60623	15.762293
Timmins TS	115	6 Northeas	TIMMINS	M8	5.973	6.03273	6.093057	6.153988	6.215528	6.277683	6.34046	6.403864	6.467903	6.532582	6.597908	6.663887	6.730526	6.797831	6.865809	6.934468	7.003812	7.07385	7.144589	7.216035	7.288195	7.3610771
Timmins TS	115	6 Northeas	TIMMINS	M9	3.403	3.43703	3.4714	3.506114	3.541175	3.576587	3.612353	3.648477	3.684961	3.721811	3.759029	3.796619	3.834586	3.872931	3.911661	3.950777	3.990285	4.030188	4.07049	4.111195	4.152307	4.1938298
Wallaceburg TS	115	1 West	KENT	M1	5.042	5.09242	5.143344	5.194778	5.246725	5.299193	5.352185	5.405706	5.459764	5.514361	5.569505	5.6252	5.681452	5.738266	5.795649	5.853605	5.912142	5.971263	6.030976	6.091285	6.152198	6.2137202
Wallaceburg TS	115	1 West	KENT	M2	7.777	7.85477	7.933318	8.012651	8.092777	8.173705	8.255442	8.337997	8.421377	8.50559	8.590646	8.676553	8.763318	8.850951	8.939461	9.028856	9.119144	9.210336	9.302439	9.395463	9.489418	9.5843121
Wallaceburg TS	115	1 West	KENT	M3	3.476	3.51076	3.545868	3.581326	3.61714	3.653311	3.689844	3.726742	3.76401	3.80165	3.839667	3.878063	3.916844	3.956012	3.995572	4.035528	4.075883	4.116642	4.157809	4.199387	4.241381	4.2837944
Wallaceburg TS	115	1 West	KENT	M5	6.414	6.47814	6.542921	6.608351	6.674434	6.741178	6.80859	6.876676	6.945443	7.014897	7.085046	7.155897	7.227456	7.29973	7.372728	7.446455	7.520919	7.596129	7.67209	7.748811	7.826299	7.9045619
Wallaceburg TS	115	1 West	KENT	M6	5.203	5.25503	5.30758	5.360656	5.414263	5.468405	5.523089	5.57832	5.634103	5.690444	5.747349	5.804822	5.862871	5.921499	5.980714	6.040521	6.100927	6.161936	6.223555	6.285791	6.348649	6.4121353
Wanstead TS	115	1 West	LAMBTON	M1	9.706	9.80306	9.901091	10.0001	10.1001	10.2011	10.30311	10.40615	10.51021	10.61531	10.72146	10.82868	10.93696	11.04633	11.1568	11.26836	11.38105	11.49486	11.60981	11.72591	11.84316	11.961596
Wanstead TS	115	1 West	LAMBTON	M2	6.615	6.68115	6.747962	6.815441	6.883596	6.952431	7.021956	7.092175	7.163097	7.234728	7.307075	7.380146	7.453948	7.528487	7.603772	7.67981	7.756608	7.834174	7.912516	7.991641	8.071557	8.1522727
Wanstead TS	115	1 West	LAMBTON	M4	6.192	6.25392	6.316459	6.379624	6.44342	6.507854	6.572933	6.638662	6.705049	6.772099	6.83982	6.908218	6.977301	7.047074	7.117544	7.18872	7.260607	7.333213	7.406545	7.480611	7.555417	7.6309709
Warden TS	230	3A Central	NEWMARKET*	M21	6.195	6.25695	6.31952	6.382715	6.446542	6.511007	6.576117	6.641879	6.708297	6.77538	6.843134	6.911565	6.980681	7.050488	7.120993	7.192203	7.264125	7.336766	7.410134	7.484235	7.559077	7.6346681
Warden TS	230	3A Central	NEWMARKET*	M31	10.2	10.302	10.40502	10.50907	10.61416	10.7203	10.82751	10.93578	11.04514	11.15559	11.26715	11.37982	11.49362	11.60855	11.72464	11.84188	11.9603	12.07991	12.2007	12.32271	12.44594	12.570398
Warden TS	230	3A Central	NEWMARKET*	M32	14	14.14	14.2814	14.42421	14.56846	14.71414	14.86128	15.00989	15.15999	15.31159	15.46471	15.61936	15.77555	15.93331	16.09264	16.25357	16.4161	16.58026	16.74606	16.91353	17.08266	17.253487
Wonderland TS	230	1 West	STRATHROY	M2	0.155	0.15655	0.158116	0.159697	0.161294	0.162907	0.164536	0.166181	0.167843	0.169521	0.171216	0.172929	0.174658	0.176404	0.178169	0.17995	0.18175	0.183567	0.185403	0.187257	0.189129	0.1910208
Woodbridge TS	230	3A Central	NEWMARKET*	M1	7.701	7.77801	7.85579	7.934348	8.013691	8.093828	8.174767	8.256514	8.339079	8.42247	8.506695	8.591762	8.67768	8.764456	8.852101	8.940622	9.030028	9.120328	9.211532	9.303647	9.396683	9.4906503
Woodbridge TS	230	3A Central	NEWMARKET*	M3	8.215	8.29715	8.380122	8.463923	8.548562	8.634048	8.720388	8.807592	8.895668	8.984625	9.074471	9.165215	9.256868	9.349436	9.442931	9.53736	9.632734	9.729061	9.826352	9.924615	10.02386	10.1241
Woodbridge TS	230	3A Central	NEWMARKET*	M4	9.5	9.595	9.69095	9.78786	9.885738	9.984595	10.08444	10.18529	10.28714	10.39001	10.49391	10.59885	10.70484	10.81189	10.92001	11.02921	11.1395	11.25089	11.3634	11.47704	11.59181	11.707723
Woodstock TS	115	1 West	BEACHVILLE	M4	9.749	9.84649	9.944955	10.0444	10.14485	10.2463	10.34876	10.45225	10.55677	10.66234	10.76896	10.87665	10.98542	11.09527	11.20622	11.31829	11.43147	11.54578	11.66124	11.77785	11.89563	12.014589
Woodstock TS	115	1 West	BEACHVILLE	M6	10.128	10.22928	10.33157	10.43489	10.53924	10.64463	10.75108	10.85859	10.96717	11.07684	11.18761	11.29949	11.41248	11.52661	11.64187	11.75829	11.87588	11.99464	12.11458	12.23573	12.35808	12.481666
Woodstock TS	115	1 West	BEACHVILLE	M9	4.561	4.60661	4.652676	4.699203	4.746195	4.793657	4.841593	4.890009	4.938909	4.988299	5.038182	5.088563	5.139449	5.190843	5.242752	5.295179	5.348131	5.401613	5.455629	5.510185	5.565287	5.6209396
Alliston TS	230	2 West Cei	ALLISTON	M1	11.518	11.63318	11.74951	11.86701	11.98568	12.10553	12.22659	12.34885	12.47234	12.59707	12.72304	12.85027	12.97877	13.10856	13.23964	13.37204	13.50576	13.64082	13.77723	13.915	14.05415	14.19469
Alliston TS	230	2 West Cei	ALLISTON	M11	14.388	14.53188	14.6772	14.82397	14.97221	15.12193	15.27315	15.42588	15.58014	15.73594	15.8933	16.05224	16.21276	16.37489	16.53863	16.70402	16.87106	17.03977	17.21017	17.38227	17.55609	17.731655
Alliston TS	230	2 West Cei	ALLISTON	M12	16.692	16.85892	17.02751	17.19778	17.36976	17.54346	17.71889	17.89608	18.07504	18.25579	18.43835	18.62274	18.80896	18.99705	19.18702	19.37889	19.57268	19.76841	19.96609	20.16575	20.36741	20.571086
Alliston TS	230	2 West Cei	ALLISTON	M3	11.09	11.2009	11.31291	11.42604	11.5403	11.6557	11.77226	11.88998	12.00888	12.12897	12.25026	12.37276	12.49649	12.62145	12.74767	12.87515	13.0039	13.13394	13.26528	13.39793	13.53191	13.667227
Alliston TS	230	2 West Cei	ALLISTON	M4	13.507	13.64207	13.77849	13.91628	14.05544	14.19599	14.33795	14.48133	14.62615	14.77241	14.92013	15.06933	15.22003	15.37223	15.52595	15.68121	15.83802	15.9964	16.15636	16.31793	16.48111	16.645918
Alliston TS	230	2 West Cei	ALLISTON	M5	10.937	11.04637	11.15683	11.2684	11.38109	11.4949	11.60985	11.72594	11.8432	11.96164	12.08125	12.20206	12.32409	12.44733	12.5718	12.69752	12.82449	12.95274	13.08226	13.21309	13.34522	13.478671
Alliston TS	230	2 West Cei	ALLISTON	M6	9.651	9.74751	9.844985	9.943435	10.04287	10.1433	10.24473	10.34718	10.45065	10.55516	10.66071	10.76732	10.87499	10.98374	11.09358	11.20451	11.31656	11.42972	11.54402	11.65946	11.77605	11.893815
Almonte TS	230	4 East	PERTH	M25	8.577	8.66277	8.749398	8.836892	8.925261	9.014513	9.104658	9.195705	9.287662	9.380539	9.474344	9.569087	9.664778	9.761426	9.85904	9.957631	10.05721	10.15778	10.25936	10.36195	10.46557	10.570226
Almonte TS	230	4 East	PERTH	M26	4.984	5.03384	5.084178	5.13502	5.18637	5.238234	5.290616	5.343523	5.396958	5.450927	5.505437	5.560491	5.616096	5.672257	5.728979	5.786269	5.844132	5.902573	5.961599	6.021215	6.081427	6.1422414
Almonte TS	230	4 East	PERTH	M28	14.043	14.18343	14.32526	14.46852	14.6132	14.75933	14.90693	15.056	15.20656	15.35862	15.51221	15.66733	15.824	15.98224	16.14207	16.30349	16.46652	16.63119	16.7975	16.96547	17.13513	17.30648
Armitage TS	230	3A Central	NEWMARKET	M12	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Armitage TS	230	3A Central	NEWMARKET	M14	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Armitage TS	230	3A Central	NEWMARKET	M22	18.629	18.81529	19.00344	19.19348	19.38541	19.57927	19.77506	19.97281	20.17254	20.37426	20.57801	20.78379	20.99162	21.20154	21.41356	21.62769	21.84397	22.06241	22.28303	22.50586	22.73092	22.958229
Armitage TS	230	3A Central	NEWMARKET	M31	8.673	8.75973	8.847327	8.935801	9.025159	9.11541	9.206564	9.29863	9.391616	9.485532	9.580388	9.676192	9.772953	9.870683	9.96939	10.06908	10.16977	10.27147	10.37419	10.47793	10.58271	10.688535
Armitage TS	230	3A Central	NEWMARKET	M32	10.052	10.15252	10.25405	10.35659	10.46015	10.56475	10.6704	10.7771	10.88488	10.99372	11.10366	11.2147	11.32685	11.44011	11.55451	11.67006	11.78676	11.90463	12.02367	12.14391	12.26535	12.388004
Armitage TS	230	3A Central	NEWMARKET	M34	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Armitage TS	230	3A Central	NEWMARKET	M41	15.117	15.26817	15.42085	15.57506	15.73081	15.88812	16.047	16.20747	16.36954	16.53324	16.69857	16.86556	17.03421	17.20456	17.3766	17.55037	17.72587	17.90313	18.08216	18.26298	18.44561	18.630069
Armitage TS	230	3A Central	NEWMARKET	M42	19.509	19.70409	19.90113	20.10014	20.30114	20.50416	20.7092	20.91629	21.12545	21.33671	21.55007	21.76557	21.98323	22.20306	22.42509	22.64934	22.87584	23.1046	23.33564	23.569	23.80469	24.042734
Armitage TS	230	3A Central	NEWMARKET	M43	16.928	17.09728	17.26825	17.44094	17.61534	17.7915	17.96941	18.14911	18.3306	18.5139	18.69904	18.88603	19.07489	19.26564	19.4583	19.65288	19.84941	20.04791	20.24838	20.45087	20.65538	20.861931
Armitage TS	230	3A Central	NEWMARKET	M44	15.181	15.33281	15.48614	15.641	15.79741	15.95538	16.11494	16.27609	16.43885	16.60324	16.76927	16.93696	17.10633	17.27739	17.45017	17.62467	17.80092	17.97893	18.15871	18.3403	18.5237	18.708942
Arnprior TS	115	4 East	ARNPRIOR	M1	14.869	15.01769	15.16787	15.31955	15.47274	15.62747	15.78374	15.94158	16.101	16.26201	16.42463	16.58887	16.75476	16.92231	17.09153	17.26245	17.43507	17.60942	17.78552	17.96337	18.14301	18.324436
Arnprior TS	115	4 East	ARNPRIOR	M2	11.502	11.61702	11.73319	11.85052	11.96903	12.08872	12.2096	12.3317	12.45502	12.57957	12.70536	12.83242	12.96074	13.09035	13.22125	13.35346	13.487	13.62187	13.75809	13.89567	14.03463	14.174972
Barrie TS	115	5 Georgian	BARRIE	M3	5.549	5.60449	5.660535	5.71714	5.774312	5.832055	5.890375	5.949279	6.008772	6.06886	6.129548	6.190844	6.252752	6.31528	6.378432	6.442217	6.506639	6.571705	6.637422	6.703797	6.770835	6.8385429
Beaverton TS	230	3A Central	FENELON FALLS	M23	10.945	11.05445	11.16499	11.27664	11.38941	11.5033	11.61834	11.73452	11.85187	11.97039	12.09009	12.21099	12.3331	12.45643	12.581	12.70681	12.83387	12.96221	13.09183	13.22275	13.35498	13.48853
Beaverton TS	230	3A Central	FENELON FALLS	M24	7.818	7.89618	7.975142	8.054893	8.135442	8.216797	8.298965	8.381954	8.465774	8.550431	8.635936	8.722295	8.809518	8.897613	8.986589	9.076455	9.16722	9.258892	9.351481	9.444996	9.539446	9.6348402
Beaverton TS	230	3A Central	FENELON FALLS	M26	10.723	10.83023	10.93853	11.04792	11.1584	11.26998	11.38268	11.49651	11.61147	11.72759	11.84486	11.96331	12.08294	12.20377	12.32581	12.44907	12.57356	12.6993	12.82629	12.95455	13.0841	13.214939
Beaverton TS	230	3A Central	FENELON FALLS	M27	4.528	4.57328	4.619013	4.665203	4.711855	4.758974	4.806563	4.854629	4.903175	4.952207	5.001729	5.051746	5.102264	5.153286	5.204819	5.256867	5.309436	5.36253	5.416156	5.470317	5.525021	5.5802707
Beaverton TS	230	3A Central	FENELON FALLS	M29	8.839	8.92739	9.016664	9.106831	9.197899	9.289878	9.382777	9.476604	9.57137	9.667084	9.763755	9.861393	9.960006	10.05961	10.1602	10.2618	10.36442	10.46807	10.57275	10.67848	10.78526	10.893112
Beaverton TS	230	3A Central	FENELON FALLS	M30	8.231	8.31331	8.396443	8.480408	8.565212	8.650864	8.737372	8.824746	8.912994	9.002123	9.092145	9.183066	9.274897	9.367646	9.461322	9.555935	9.651495	9.74801	9.84549	9.943945	10.04338	10.143818
Belleville TS	230	3B East Ce	TRENTON	8M2	11.864	11.98264	12.10247	12.22349	12.34573	12.46918	12.59388	12.71981	12.84701	12.97548	13.10524	13.23629	13.36865	13.50234	13.63736	13.77374	13.91147	14.05059	14.19109	14.333	14.47633	14.621098
Belleville TS	230	3B East Ce	TRENTON	8M5	14.712	14.85912	15.00771	15.15779	15.30937	15.46246	15.61708	15.77326	15.93099	16.0903	16.2512	16.41371	16.57785	16.74363	16.91106	17.08018	17.25098	17.42349	17.59772	17.7737	17.95144	18.13095
Belleville TS	230	3B East Ce	TRENTON	8M6	12.349	12.47249	12.59721	12.72319	12.85042	12.97892	13.10871	13.2398	13.3722	13.50592	13.64098	13.77739	13.91516	14.05431	14.19486	14.33681	14.48017	14.62498	14.77123	14.91894	15.06813	15.218808
Belleville TS	230	3B East Ce	TRENTON	8M7	10.078	10.17878	10.28057	10.38337	10.48721	10.59208	10.698	10.80498	10.91303	11.02216	11.13238	11.24371	11.35614	11.4697	11.5844	11.70025	11.81725	11.93542	12.05477	12.17532	12.29708	12.420046
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M23	15.01	15.1601	15.3117	15.46482	15.61947	15.77566	15.93342	16.09275	16.25368	16.41622	16.58038	16.74618	16.91364	17.08278	17.25361	17.42614	17.60041	17.77641	17.95417	18.13372	18.31505	18.498203
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M24	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M45	30.385	30.68885	30.99574	31.3057	31.61875	31.93494	32.25429	32.57683	32.9026	33.23163	33.56394	33.89958	34.23858	34.58096	34.92677	35.27604	35.6288	35.98509	36.34494	36.70839	37.07547	37.446229
Bramalea TS	230	2 West Cei	ORANGEVILLE*	M46	25.63	25.8863	26.14516	26.40661	26.67068	26.93739	27.20676	27.47883	27.75362	28.03115	28.31147	28.59458	28.88053	29.16933	29.46102	29.75563	30.05319	30.35372	30.65726	30.96383	31.27347	31.586205
Brockville TS	230	4 East	BROCKVILLE	B1R	18.601	18.78701	18.97488	19.16463	19.35628	19.54984	19.74534	19.94279	20.14222	20.34364	20.54708	20.75255	20.96007	21.16967	21.38137	21.59518	21.81114	22.02925	22.24954	22.47203	22.69675	22.923722
Brockville TS	230	4 East	BROCKVILLE	M1	11.42	11.5342	11.64954	11.76604	11.8837	12.00253	12.12256	12.24379	12.36622	12.48989	12.61478	12.74093	12.86834	12.99703	13.127	13.25827	13.39085	13.52476	13.66	13.7966	13.93457	14.073916
Brockville TS	230	4 East	BROCKVILLE	M2	9.749	9.84649	9.944955	10.0444	10.14485	10.2463	10.34876	10.45225	10.55677	10.66234	10.76896	10.87665	10.98542	11.09527	11.20622	11.31829	11.43147	11.54578	11.66124	11.77785	11.89563	12.014589
Brockville TS	230	4 East	BROCKVILLE	M3	16.894	17.06294	17.23357	17.40591	17.57996	17.75576	17.93332	18.11265	18.29378	18.47672	18.66149	18.8481	19.03658	19.22695	19.41922	19.61341	19.80954	20.00764	20.20772	20.40979	20.61389	20.820029
Brockville TS	230	4 East	BROCKVILLE	M4	11.914	12.03314	12.15347	12.27501	12.39776	12.52173	12.64695	12.77342	12.90115	13.03017	13.16047	13.29207	13.42499	13.55924	13.69484	13.83178	13.9701	14.1098	14.2509	14.39341	14.53734	14.682718
Brockville TS	230	4 East	BROCKVILLE	M5	9.671	9.76771	9.865387	9.964041	10.06368	10.16432	10.26596	10.36862	10.47231	10.57703	10.6828	10.78963	10.89752	11.0065	11.11657	11.22773	11.34001	11.45341	11.56794	11.68362	11.80046	11.918462
Brockville TS	230	4 East	BROCKVILLE	M6	8.935	9.02435	9.114594	9.205739	9.297797	9.390775	9.484683	9.579529	9.675325	9.772078	9.869799	9.968497	10.06818	10.16886	10.27055	10.37326	10.47699	10.58176	10.68758	10.79445	10.9024	11.011422
Brown Hill TS	230	3A Central	NEWMARKET	M1	10.957	11.06657	11.17724	11.28901	11.4019	11.51592	11.63108	11.74739	11.86486	11.98351	12.10334	12.22438	12.34662	12.47009	12.59479	12.72074	12.84794	12.97642	13.10619	13.23725	13.36962	13.503318

Brown Hill TS	230	3A Central	NEWMARKET	M11	8.642	8.72842	8.815704	8.903861	8.9929	9.082829	9.173657	9.265394	9.358048	9.451628	9.546144	9.641606	9.738022	9.835402	9.933756	10.03309	10.13342	10.23476	10.33711	10.44048	10.54488	10.650331
Brown Hill TS	230	3A Central	NEWMARKET	M12	7.048	7.11848	7.189665	7.261561	7.334177	7.407519	7.481594	7.55641	7.631974	7.708294	7.785377	7.863231	7.941863	8.021281	8.101494	8.182509	8.264334	8.346978	8.430447	8.514752	8.599899	8.6858984
Brown Hill TS	230	3A Central	NEWMARKET	M2	6.687	6.75387	6.821409	6.889623	6.958519	7.028104	7.098385	7.169369	7.241063	7.313473	7.386608	7.460474	7.535079	7.61043	7.686534	7.763399	7.841033	7.919444	7.998638	8.078625	8.159411	8.2410049
Brown Hill TS	230	3A Central	NEWMARKET	M3	8.214	8.29614	8.379101	8.462892	8.547521	8.632997	8.719327	8.80652	8.894585	8.983531	9.073366	9.1641	9.255741	9.348298	9.441781	9.536199	9.631561	9.727877	9.825155	9.923407	10.02264	10.122867
Cherrywood TS	500	3A Central	NEWMARKET*	M6	16.048	16.20848	16.37056	16.53427	16.69961	16.86661	17.03528	17.20563	17.37768	17.55146	17.72698	17.90425	18.08329	18.26412	18.44676	18.63123	18.81754	19.00572	19.19577	19.38773	19.58161	19.777426
Cherrywood TS	500	3A Central	NEWMARKET*	M7	15.638	15.79438	15.95232	16.11185	16.27297	16.4357	16.60005	16.76605	16.93371	17.10305	17.27408	17.44682	17.62129	17.7975	17.97548	18.15523	18.33678	18.52015	18.70535	18.89241	19.08133	19.272145
Cherrywood TS	500	3A Central	NEWMARKET*	M8	20.953	21.16253	21.37416	21.5879	21.80378	22.02181	22.24203	22.46445	22.6891	22.91599	23.14515	23.3766	23.61036	23.84647	24.08493	24.32578	24.56904	24.81473	25.06288	25.31351	25.56664	25.822308
Chesterville TS	115	4 East	WINCHESTER	M2	10.53	10.6353	10.74165	10.84907	10.95756	11.06714	11.17781	11.28959	11.40248	11.51651	11.63167	11.74799	11.86547	11.98412	12.10396	12.225	12.34725	12.47073	12.59543	12.72139	12.8486	12.977087
Chesterville TS	115	4 East	WINCHESTER	M4	13.981	14.12081	14.26202	14.40464	14.54868	14.69417	14.84111	14.98952	15.13942	15.29081	15.44372	15.59816	15.75414	15.91168	16.0708	16.23151	16.39382	16.55776	16.72334	16.89057	17.05948	17.230072
Clarabelle TS	230	6 Northeas	SUDBURY	M7	6.709	6.77609	6.843851	6.912289	6.981412	7.051226	7.121739	7.192956	7.264886	7.337534	7.41091	7.485019	7.559869	7.635468	7.711822	7.788941	7.86683	7.945498	8.024953	8.105203	8.186255	8.2681175
Clarabelle TS	230	6 Northeas	SUDBURY	M8	18.594	18.77994	18.96774	19.15742	19.34899	19.54248	19.73791	19.93528	20.13464	20.33598	20.53934	20.74474	20.95218	21.16171	21.37332	21.58706	21.80293	22.02096	22.24117	22.46358	22.68821	22.915096
Cobden TS	115	3B East Ce	COBDEN	M2	5.194	5.24594	5.298399	5.351383	5.404897	5.458946	5.513536	5.568671	5.624358	5.680601	5.737407	5.794781	5.852729	5.911256	5.970369	6.030073	6.090373	6.151277	6.21279	6.274918	6.337667	6.4010437
Cobden TS	115	3B East Ce	COBDEN	M6	10	10.1	10.201	10.30301	10.40604	10.5101	10.6152	10.72135	10.82857	10.93685	11.04622	11.15668	11.26825	11.38093	11.49474	11.60969	11.72579	11.84304	11.96147	12.08109	12.2019	12.323919
Crosby TS	230	4 East	PERTH	M1	6.502	6.56702	6.63269	6.699017	6.766007	6.833667	6.902004	6.971024	7.040734	7.111142	7.182253	7.254076	7.326616	7.399883	7.473881	7.54862	7.624106	7.700347	7.777351	7.855124	7.933676	8.0130124
Crosby TS	230	4 East	PERTH	M2	6.543	6.60843	6.674514	6.741259	6.808672	6.876759	6.945526	7.014982	7.085131	7.155983	7.227543	7.299818	7.372816	7.446544	7.52101	7.59622	7.672182	7.748904	7.826393	7.904657	7.983703	8.0635405
Crystal Falls TS	230	6 Northeas	NIPISSING	M1	3.785	3.82285	3.861079	3.899689	3.938686	3.978073	4.017854	4.058032	4.098613	4.139599	4.180995	4.222805	4.265033	4.307683	4.35076	4.394267	4.43821	4.482592	4.527418	4.572692	4.618419	4.6646035
Crystal Falls TS	230	6 Northeas	NIPISSING	M2	7.515	7.59015	7.666052	7.742712	7.820139	7.898341	7.977324	8.057097	8.137668	8.219045	8.301235	8.384248	8.46809	8.552771	8.638299	8.724682	8.811929	8.900048	8.989048	9.078939	9.169728	9.2614254
Dobbin TS	230	3A Central	PETERBOROUGI	M1	10	10.1	10.201	10.30301	10.40604	10.5101	10.6152	10.72135	10.82857	10.93685	11.04622	11.15668	11.26825	11.38093	11.49474	11.60969	11.72579	11.84304	11.96147	12.08109	12.2019	12.323919
Dobbin TS	230	3A Central	PETERBOROUGI	M2	12.812	12.94012	13.06952	13.20022	13.33222	13.46554	13.6002	13.7362	13.87356	14.0123	14.15242	14.29394	14.43688	14.58125	14.72706	14.87433	15.02308	15.17331	15.32504	15.47829	15.63307	15.789406
Dobbin TS	230	3A Central	PETERBOROUGI	M3	0.324	0.32724	0.330512	0.333818	0.337156	0.340527	0.343933	0.347372	0.350846	0.354354	0.357898	0.361477	0.365091	0.368742	0.37243	0.376154	0.379915	0.383715	0.387552	0.391427	0.395342	0.399295
Dobbin TS	230	3A Central	PETERBOROUGI	M4	17	17.17	17.3417	17.51512	17.69027	17.86717	18.04584	18.2263	18.40856	18.59265	18.77858	18.96636	19.15603	19.34759	19.54106	19.73647	19.93384	20.13318	20.33451	20.53785	20.74323	20.950663
Dobbin TS	230	3A Central	PETERBOROUGI	M5	9.707	9.80407	9.902111	10.00113	10.10114	10.20215	10.30418	10.40722	10.51129	10.6164	10.72257	10.82979	10.93809	11.04747	11.15795	11.26953	11.38222	11.49604	11.611	11.72711	11.84438	11.962829
Dobbin TS	230	3A Central	PETERBOROUGI	M6	11.537	11.65237	11.76889	11.88658	12.00545	12.1255	12.24676	12.36923	12.49292	12.61785	12.74403	12.87147	13.00018	13.13018	13.26148	13.3941	13.52804	13.66332	13.79995	13.93795	14.07733	14.218106
Dobbin TS	230	3A Central	PETERBOROUGI	M7	13	13.13	13.2613	13.39391	13.52785	13.66313	13.79976	13.93776	14.07714	14.21791	14.36009	14.50369	14.64873	14.79521	14.94316	15.0926	15.24352	15.39596	15.54992	15.70542	15.86247	16.021095
Dobbin TS	230	3A Central	PETERBOROUGI	M8	17	17.17	17.3417	17.51512	17.69027	17.86717	18.04584	18.2263	18.40856	18.59265	18.77858	18.96636	19.15603	19.34759	19.54106	19.73647	19.93384	20.13318	20.33451	20.53785	20.74323	20.950663
Douglas Point TS	230	1 West	WALKERTON	M1	8.764	8.85164	8.940156	9.029558	9.119854	9.211052	9.303163	9.396194	9.490156	9.585058	9.680908	9.777717	9.875495	9.97425	10.07399	10.17473	10.27648	10.37924	10.48304	10.58787	10.69375	10.800683
Douglas Point TS	230	1 West	WALKERTON	M2	0.828	0.83628	0.844643	0.853089	0.86162	0.870236	0.878939	0.887728	0.896605	0.905571	0.914627	0.923773	0.933011	0.942341	0.951765	0.961282	0.970895	0.980604	0.99041	1.000314	1.010317	1.0204205
Douglas Point TS	230	1 West	WALKERTON	M3	0.748	0.75548	0.763035	0.770665	0.778372	0.786156	0.794017	0.801957	0.809977	0.818077	0.826257	0.83452	0.842865	0.851294	0.859807	0.868405	0.877089	0.88586	0.894718	0.903665	0.912702	0.9218292
Douglas Point TS	230	1 West	WALKERTON	M4	8.041	8.12141	8.202624	8.28465	8.367497	8.451172	8.535684	8.62104	8.707251	8.794323	8.882267	8.971089	9.0608	9.151408	9.242922	9.335351	9.428705	9.522992	9.618222	9.714404	9.811548	9.9096636
Douglas Point TS	230	1 West	WALKERTON	M8	8.603	8.68903	8.77592	8.86368	8.952316	9.041839	9.132258	9.22358	9.315816	9.408974	9.503064	9.598095	9.694076	9.791016	9.888927	9.987816	10.08769	10.18857	10.29046	10.39336	10.49729	10.602268
Dryden TS	230	7 Northwes	DRYDEN	M1	9.05	9.1405	9.231905	9.324224	9.417466	9.511641	9.606757	9.702825	9.799853	9.897852	9.99683	10.0968	10.19777	10.29974	10.40274	10.50677	10.61184	10.71796	10.82513	10.93339	11.04272	11.153147
Dryden TS	230	7 Northwes	DRYDEN	M3	2.14	2.1614	2.183014	2.204844	2.226893	2.249162	2.271653	2.29437	2.317313	2.340486	2.363891	2.38753	2.411406	2.43552	2.459875	2.484474	2.509318	2.534411	2.559756	2.585353	2.611207	2.6373188
Dymond TS	230	6 Northeas	NEW LISKEARD	M1	20.894	21.10294	21.31397	21.52711	21.74238	21.9598	22.1794	22.4012	22.62521	22.85146	23.07997	23.31077	23.54388	23.77932	24.01711	24.25729	24.49986	24.74486	24.99231	25.24223	25.49465	25.749597
Dymond TS	230	6 Northeas	NEW LISKEARD	M3	16.144	16.30544	16.46849	16.63318	16.79951	16.96751	17.13718	17.30855	17.48164	17.65646	17.83302	18.01135	18.19146	18.37338	18.55711	18.74268	18.93011	19.11941	19.3106	19.50371	19.69875	19.895735
Elliot Lake TS	115	6 Northeas	ALGOMA	M1	16.882	17.05082	17.22133	17.39354	17.56748	17.74315	17.92058	18.09979	18.28079	18.46359	18.64823	18.83471	19.02306	19.21329	19.40542	19.59948	19.79547	19.99343	20.19336	20.3953	20.59925	20.805241
Elliot Lake TS	115	6 Northeas	ALGOMA	M3	10.98	11.0898	11.2007	11.3127	11.42583	11.54009	11.65549	11.77205	11.88977	12.00866	12.12875	12.25004	12.37254	12.49626	12.62123	12.74744	12.87491	13.00366	13.1337	13.26504	13.39769	13.531664
Espanola TS	115	6 Northeas	ALGOMA	M1	4.032	4.07232	4.113043	4.154174	4.195715	4.237673	4.280049	4.32285	4.366078	4.409739	4.453836	4.498375	4.543359	4.588792	4.63468	4.681027	4.727837	4.775115	4.822867	4.871095	4.919806	4.9690043
Espanola TS	115	6 Northeas	ALGOMA	M2	6.617	6.68317	6.750002	6.817502	6.885677	6.954534	7.024079	7.09432	7.165263	7.236915	7.309285	7.382377	7.456201	7.530763	7.606071	7.682132	7.758953	7.836542	7.914908	7.994057	8.073997	8.1547375
Fergus TS	230	2 West Ce	GUELPH	M1	13.52	13.6552	13.79175	13.92967	14.06897	14.20966	14.35175	14.49527	14.64022	14.78662	14.93449	15.08384	15.23467	15.38702	15.54089	15.6963	15.85326	16.0118	16.17191	16.33363	16.49697	16.661939
Fergus TS	230	2 West Ce	GUELPH	M2	5.268	5.32068	5.373887	5.427626	5.481902	5.536721	5.592088	5.648009	5.704489	5.761534	5.819149	5.877341	5.936114	5.995475	6.05543	6.115984	6.177144	6.238916	6.301305	6.364318	6.427961	6.4922407
Fergus TS	230	2 West Ce	GUELPH	M3	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Fergus TS	230	2 West Ce	GUELPH	M4	18.703	18.89003	19.07893	19.26972	19.46242	19.65704	19.85361	20.05215	20.25267	20.4552	20.65975	20.86635	21.07501	21.28576	21.49862	21.7136	21.93074	22.15005	22.37155	22.59526	22.82121	23.049426
Fergus TS	230	2 West Ce	GUELPH	M7	19.186	19.37786	19.57164	19.76735	19.96503	20.16468	20.36633	20.56999	20.77569	20.98345	21.19328	21.40521	21.61927	21.83546	22.05381	22.27435	22.49709	22.72206	22.94929	23.17878	23.41057	23.644672
Fergus TS	230	2 West Ce	GUELPH	M8	5.884	5.94284	6.002268	6.062291	6.122914	6.184143	6.245985	6.308444	6.371529	6.435244	6.499597	6.564593	6.630238	6.696541	6.763506	6.831141	6.899453	6.968447	7.038132	7.108513	7.179598	7.2513942
Fort Frances TS	230	7 Northwes	FORT FRANCES	M1	9.104	9.19504	9.28699	9.37986	9.473659	9.568395	9.664079	9.76072	9.858327	9.956911	10.05648	10.15704	10.25862	10.3612	10.46481	10.56946	10.67516	10.78191	10.88973	10.99862	11.10861	11.219696
Frontenac TS	115	3B East Ce	KINGSTON	M1	15.707	15.86407	16.02271	16.18294	16.34477	16.50821	16.6733	16.84003	17.00843	17.17851	17.3503	17.5238	17.69904	17.87603	18.05479	18.23534	18.41769	18.60187	18.78789	18.97577	19.16552	19.35718
Frontenac TS	115	3B East Ce	KINGSTON	M3	14.129	14.27029	14.41299	14.55712	14.70269	14.84972	14.99822	15.1482	15.29968	15.45268	15.60721	15.76328	15.92091	16.08012	16.24092	16.40333	16.56736	16.73304	16.90037	17.06937	17.24007	17.412466
Frontenac TS	115	3B East Ce	KINGSTON	M8	13.562	13.69762	13.8346	13.97294	14.11267	14.2538	14.39634	14.5403	14.6857	14.83256	14.98089	15.13069	15.282	15.43482	15.58917	15.74506	15.90251	16.06154	16.22215	16.38437	16.54822	16.713699
Gardiner TS	230	3B East Ce	KINGSTON	33M10	9.648	9.74448	9.841925	9.940344	10.03975	10.14014	10.24155	10.34396	10.4474	10.55188	10.65739	10.76397	10.87161	10.98032	11.09013	11.20103	11.31304	11.42617	11.54043	11.65584	11.77239	11.890117
Gardiner TS	230	3B East Ce	KINGSTON	33M11	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Gardiner TS	230	3B East Ce	KINGSTON	33M12	14.264	14.40664	14.55071	14.69621	14.84318	14.99161	15.14152	15.29294	15.44587	15.60033	15.75633	15.91389	16.07303	16.23376	16.3961	16.56006	16.72566	16.89292	17.06185	17.23247	17.40479	17.578839
Gardiner TS	230	3B East Ce	KINGSTON	33M13	13.4	13.534	13.66934	13.80603	13.94409	14.08353	14.22437	14.36661	14.51028	14.65538	14.80194	14.94996	15.09946	15.25045	15.40295	15.55698	15.71255	15.86968	16.02838	16.18866	16.35055	16.514052
Gardiner TS	230	3B East Ce	KINGSTON	33M14	17.365	17.53865	17.71404	17.89118	18.07009	18.25079	18.4333	18.61763	18.80381	18.99184	19.18176	19.37358	19.56732	19.76299	19.96062	20.16023	20.36183	20.56545	20.7711	20.97881	21.1886	21.400486
Gardiner TS	230	3B East Ce	KINGSTON	33M15	12.863	12.99163	13.12155	13.25276	13.38529	13.51914	13.65433	13.79088	13.92879	14.06807	14.20875	14.35084	14.49435	14.63929	14.78569	14.93354	15.08288	15.23371	15.38604	15.53991	15.6953	15.852258
Gardiner TS	230	3B East Ce	KINGSTON	33M3	12.328	12.45128	12.57579	12.70155	12.82857	12.95685	13.08642	13.21728	13.34946	13.48295	13.61778	13.75396	13.8915	14.03041	14.17072	14.31243	14.45555	14.60011	14.74611	14.89357	15.0425	15.192928
Gardiner TS	230	3B East Ce	KINGSTON	33M7	21.545	21.76045	21.97805	22.19784	22.41981	22.64401	22.87045	23.09916	23.33015	23.56345	23.79908	24.03707	24.27745	24.52022	24.76542	25.01308	25.26321	25.51584	25.771	26.02871	26.28899	26.551884
Gardiner TS	230	3B East Ce	KINGSTON	33M9	19.617	19.81317	20.0113	20.21141	20.41353	20.61766	20.82384	21.03208	21.2424	21.45482	21.66937	21.88607	22.10493	22.32598	22.54924	22.77473	23.00248	23.2325	23.46483	23.69947	23.93647	24.175833
Hanover TS	230	1 West	WALKERTON	H1E	13.119	13.25019	13.38269	13.51652	13.65168	13.7882	13.92608	14.06534	14.206	14.34806	14.49154	14.63645	14.78282	14.93065	15.07995	15.23075	15.38306	15.53689	15.69226	15.84918	16.00767	16.16775
Hanover TS	230	1 West	WALKERTON	M1	13.312	13.44512	13.57957	13.71537	13.85252	13.99105	14.13096	14.27227	14.41499	14.55914	14.70473	14.85178	15.00029	15.1503	15.3018	15.45482	15.60937	15.76546	15.92312	16.08235	16.24317	16.405602
Hanover TS	230	1 West	WALKERTON	M2	12.733	12.86033	12.98893	13.11882	13.25001	13.38251	13.51634	13.6515	13.78801	13.92589	14.06515	14.20581	14.34786	14.49134	14.63626	14.78262	14.93044	15.07975	15.23055	15.38285	15.53668	15.692047
Hanover TS	230	1 West	WALKERTON	M3	7.676	7.75276	7.830288	7.90859	7.987676	8.067553	8.148229	8.229711	8.312008	8.395128	8.479079	8.56387	8.649509	8.736004	8.823364	8.911598	9.000714	9.090721	9.181628	9.273444	9.366179	9.4598405
Hanover TS	230	1 West	WALKERTON	M4	9.561	9.65661	9.753176	9.850708	9.949215	10.04871	10.14919	10.25069	10.35319	10.45672	10.56129	10.66691	10.77357	10.88131	10.99012	11.10002	11.21102	11.32313	11.43637	11.55073	11.66624	11.782899
Hanover TS	230	1 West	WALKERTON	M5	15.841	15.99941	16.1594	16.321	16.48421	16.64905	16.81554	16.9837	17.15353	17.32507	17.49832	17.6733	17.85004	18.02854	18.20882	18.39091	18.57482	18.76057	18.94817	19.13765	19.32903	19.522321
Havelock TS	230	3B East Ce	TWEED	M1	8.786	8.87386	8.962599	9.052225	9.142747	9.234174	9.326516	9.419781	9.513979	9.609119	9.70521	9.802262	9.900285	9.999288	10.09928	10.20027	10.30228	10.4053	10.50935	10.61445	10.72059	10.827796
Havelock TS	230	3B East Ce	TWEED	M2	13.44	13.5744	13.71014	13.84725	13.98572	14.12558	14.26683	14.4095	14.55359	14.69913	14.84612	14.99458	15.14453	15.29597	15.44893	15.60342	15.75946	15.91705	16.07622	16.23698	16.39935	16.563348
Havelock TS	230	3B East Ce	TWEED	M3	4.123	4.16423	4.205872	4.247931	4.29041	4.333314	4.376648	4.420414	4.464618	4.509264	4.554357	4.599901	4.6459	4.692359	4.739282	4.786675	4.834542	4.882887	4.931716	4.981033	5.030844	5.081152

Havelock TS	230	3B East Ce	TWEED	M4	5.529	5.58429	5.640133	5.696534	5.7535	5.811035	5.869145	5.927836	5.987115	6.046986	6.107456	6.16853	6.230216	6.292518	6.355443	6.418997	6.483187	6.548019	6.613499	6.679634	6.746431	6.813895
Havelock TS	230	3B East Ce	TWEED	M6	11.451	11.56551	11.68117	11.79798	11.91596	12.03512	12.15547	12.27702	12.39979	12.52379	12.64903	12.77552	12.90327	13.03231	13.16263	13.29426	13.4272	13.56147	13.69708	13.83406	13.9724	14.11212
Hawthorne TS	500	4 East	WINCHESTER	M1	12.95	13.0795	13.2103	13.3424	13.47582	13.61058	13.74669	13.88415	14.02299	14.16322	14.30486	14.44791	14.59238	14.73831	14.88569	15.03455	15.18489	15.33674	15.49011	15.64501	15.80146	15.959476
Hawthorne TS	500	4 East	WINCHESTER	M2	25.57	25.8257	26.08396	26.3448	26.60824	26.87433	27.14307	27.4145	27.68865	27.96553	28.24519	28.52764	28.81292	29.10105	29.39206	29.68598	29.98284	30.28266	30.58549	30.89135	31.20026	31.512262
Kirkland Lake TS	115	6 Northeas	KIRKLAND LAKE	G3K	5.226	5.27826	5.331043	5.384353	5.438197	5.492579	5.547504	5.602979	5.659009	5.715599	5.772755	5.830483	5.888788	5.947675	6.007152	6.067224	6.127896	6.189175	6.251067	6.313577	6.376713	6.4404803
Kirkland Lake TS	115	6 Northeas	KIRKLAND LAKE	M61	7.567	7.64267	7.719097	7.796288	7.874251	7.952993	8.032523	8.112848	8.193977	8.275916	8.358676	8.442262	8.526685	8.611952	8.698071	8.785052	8.872903	8.961632	9.051248	9.14176	9.233178	9.3255098
Kirkland Lake TS	115	6 Northeas	KIRKLAND LAKE	M62	3.045	3.07545	3.106205	3.137267	3.168639	3.200326	3.232329	3.264652	3.297299	3.330272	3.363574	3.39721	3.431182	3.465494	3.500149	3.53515	3.570502	3.606207	3.642269	3.678692	3.715479	3.7526335
Kleinburg TS	230	3A Central	NEWMARKET	M23	16.723	16.89023	17.05913	17.22972	17.40202	17.57604	17.7518	17.92932	18.10861	18.2897	18.4726	18.65732	18.84389	19.03233	19.22266	19.41488	19.60903	19.80512	20.00317	20.20321	20.40524	20.60929
Kleinburg TS	230	3A Central	NEWMARKET	M24	17.044	17.21444	17.38658	17.56045	17.73605	17.91342	18.09255	18.27347	18.45621	18.64077	18.82718	19.01545	19.20561	19.39766	19.59164	19.78755	19.98543	20.18528	20.38714	20.59101	20.79692	21.004888
Kleinburg TS	230	3A Central	NEWMARKET	M25	22	22.22	22.4422	22.66662	22.89329	23.12222	23.35344	23.58698	23.82285	24.06108	24.30169	24.5447	24.79015	25.03805	25.28843	25.54132	25.79673	26.0547	26.31524	26.5784	26.84418	27.112623
Kleinburg TS	230	3A Central	NEWMARKET	M26	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Larchwood TS	115	6 Northeas	SUDBURY	M3	2.412	2.43612	2.460481	2.485086	2.509937	2.535036	2.560387	2.58599	2.61185	2.637969	2.664349	2.690992	2.717902	2.745081	2.772532	2.800257	2.82826	2.856542	2.885108	2.913959	2.943098	2.9725294
Larchwood TS	115	6 Northeas	SUDBURY	M4	13.959	14.09859	14.23958	14.38197	14.52579	14.67105	14.81776	14.96594	15.1156	15.26675	15.41942	15.57361	15.72935	15.88664	16.04551	16.20597	16.36803	16.53171	16.69702	16.86399	17.03263	17.202959
Lindsay TS	230	3A Central	FENELON FALLS	M3	4.408	4.45208	4.496601	4.541567	4.586982	4.632852	4.679181	4.725973	4.773232	4.820965	4.869174	4.917866	4.967045	5.016715	5.066882	5.117551	5.168727	5.220414	5.272618	5.325344	5.378598	5.4323837
Lindsay TS	230	3A Central	FENELON FALLS	M4	7.065	7.13565	7.207007	7.279077	7.351867	7.425386	7.49964	7.574636	7.650383	7.726886	7.804155	7.882197	7.961019	8.040629	8.121035	8.202246	8.284268	8.367111	8.450782	8.53529	8.620643	8.7068491
Lindsay TS	230	3A Central	FENELON FALLS	M5	9.831	9.92931	10.0286	10.12889	10.23018	10.33248	10.4358	10.54016	10.64556	10.75202	10.85954	10.96814	11.07782	11.1886	11.30048	11.41349	11.52762	11.6429	11.75933	11.87692	11.99569	12.115645
Lindsay TS	230	3A Central	FENELON FALLS	M6	16.95	17.1195	17.2907	17.4636	17.63824	17.81462	17.99277	18.17269	18.35442	18.53797	18.72335	18.91058	19.09968	19.29068	19.48359	19.67842	19.87521	20.07396	20.2747	20.47745	20.68222	20.889043
Lindsay TS	230	3A Central	FENELON FALLS	M7	6.585	6.65085	6.717359	6.784532	6.852377	6.920901	6.99011	7.060011	7.130611	7.201918	7.273937	7.346676	7.420143	7.494344	7.569288	7.644981	7.72143	7.798645	7.876631	7.955397	8.034951	8.1153009
Lindsay TS	230	3A Central	FENELON FALLS	M8	9.544	9.63944	9.735834	9.833193	9.931525	10.03084	10.13115	10.23246	10.33478	10.43813	10.54251	10.64794	10.75442	10.86196	10.97058	11.08029	11.19109	11.303	11.41603	11.53019	11.64549	11.761949
Longueuil TS	230	4 East	VANKLEEK HILL	M23	7.327	7.40027	7.474273	7.549015	7.624506	7.700751	7.777758	7.855536	7.934091	8.013432	8.093566	8.174502	8.256247	8.338809	8.422198	8.50642	8.591484	8.677399	8.764173	8.851814	8.940332	9.0297357
Longueuil TS	230	4 East	VANKLEEK HILL	M24	15.397	15.55097	15.70648	15.86354	16.02218	16.1824	16.34423	16.50767	16.67274	16.83947	17.00787	17.17795	17.34972	17.52322	17.69845	17.87544	18.05419	18.23474	18.41708	18.60125	18.78727	18.975139
Longueuil TS	230	4 East	VANKLEEK HILL	M25	7.572	7.64772	7.724197	7.801439	7.879454	7.958248	8.037831	8.118209	8.199391	8.281385	8.364199	8.447841	8.532319	8.617642	8.703819	8.790857	8.878765	8.967553	9.057229	9.147801	9.239279	9.3316718
Longueuil TS	230	4 East	VANKLEEK HILL	M26	5.542	5.59742	5.653394	5.709928	5.767027	5.824698	5.882945	5.941774	6.001192	6.061204	6.121816	6.183034	6.244864	6.307313	6.370386	6.43409	6.498431	6.563415	6.629049	6.69534	6.762293	6.8299161
Martindale TS	230	6 Northeas	SUDBURY	M5	10.232	10.33432	10.43766	10.54204	10.64746	10.75393	10.86147	10.97009	11.07979	11.19059	11.30249	11.41552	11.52967	11.64497	11.76142	11.87903	11.99782	12.1178	12.23898	12.36137	12.48498	12.609834
Martindale TS	230	6 Northeas	SUDBURY	M6	13.946	14.08546	14.22631	14.36858	14.51226	14.65739	14.80396	14.952	15.10152	15.25253	15.40506	15.55911	15.7147	15.87185	16.03057	16.19087	16.35278	16.51631	16.68147	16.84829	17.01677	17.186938
Martindale TS	230	6 Northeas	SUDBURY	M7	7.671	7.74771	7.825187	7.903439	7.982473	8.062298	8.142921	8.22435	8.306594	8.38966	8.473556	8.558292	8.643875	8.730314	8.817617	8.905793	8.994851	9.084799	9.175647	9.267404	9.360078	9.4536786
Meaford TS	115	5 Georgian	OWEN SOUND	M1	6.406	6.47006	6.534761	6.600108	6.666109	6.73277	6.800098	6.868099	6.93678	7.006148	7.076209	7.146971	7.218441	7.290626	7.363532	7.437167	7.511539	7.586654	7.662521	7.739146	7.816537	7.8947028
Meaford TS	115	5 Georgian	OWEN SOUND	M2	14.472	14.61672	14.76289	14.91052	15.05962	15.21022	15.36232	15.51594	15.6711	15.82781	15.98609	16.14595	16.30741	16.47049	16.63519	16.80154	16.96956	17.13925	17.31065	17.48375	17.65859	17.835176
Midhurst TS	230	5 Georgian	BARRIE	M10	19.294	19.48694	19.68181	19.87863	20.07741	20.27819	20.48097	20.68578	20.89264	21.10156	21.31258	21.52571	21.74096	21.95837	22.17796	22.39974	22.62373	22.84997	23.07847	23.30925	23.54235	23.77777
Midhurst TS	230	5 Georgian	BARRIE	M3	10.22	10.3222	10.42542	10.52968	10.63497	10.74132	10.84874	10.95722	11.0668	11.17746	11.28924	11.40213	11.51615	11.63131	11.74763	11.8651	11.98375	12.10359	12.22463	12.34687	12.47034	12.595046
Midhurst TS	230	5 Georgian	BARRIE	M4	12.435	12.55935	12.68494	12.81179	12.93991	13.06931	13.2	13.332	13.46532	13.59998	13.73598	13.87334	14.01207	14.15219	14.29371	14.43665	14.58102	14.72683	14.87409	15.02283	15.17306	15.324794
Midhurst TS	230	5 Georgian	BARRIE	M5	17.688	17.86488	18.04353	18.22396	18.4062	18.59027	18.77617	18.96393	19.15357	19.34511	19.53856	19.73394	19.93128	20.13059	20.3319	20.53522	20.74057	20.94798	21.15746	21.36903	21.58272	21.798549
Midhurst TS	230	5 Georgian	BARRIE	M6	14.152	14.29352	14.43646	14.58082	14.72663	14.87389	15.02263	15.17286	15.32459	15.47783	15.63261	15.78894	15.94683	16.1063	16.26736	16.43003	16.59433	16.76028	16.92788	17.09716	17.26813	17.440811
Midhurst TS	230	5 Georgian	BARRIE	M7	23.047	23.27747	23.51024	23.74535	23.9828	24.22263	24.46485	24.7095	24.9566	25.20616	25.45823	25.71281	25.96994	26.22964	26.49193	26.75685	27.02442	27.29466	27.56761	27.84329	28.12172	28.402937
Midhurst TS	230	5 Georgian	BARRIE	M8	17.85	18.0285	18.20879	18.39087	18.57478	18.76053	18.94813	19.13762	19.32899	19.52228	19.7175	19.91468	20.11383	20.31497	20.51811	20.7233	20.93053	21.13983	21.35123	21.56474	21.78039	21.998196
Midhurst TS	230	5 Georgian	BARRIE	M9	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Minden TS	230	3A Central	MINDEN	M1	10.771	10.87871	10.9875	11.09737	11.20835	11.32043	11.43363	11.54797	11.66345	11.78008	11.89788	12.01686	12.13703	12.2584	12.38099	12.5048	12.62984	12.75614	12.8837	13.01254	13.14267	13.274094
Minden TS	230	3A Central	MINDEN	M2	9.42	9.5142	9.609342	9.705435	9.80249	9.900515	9.99952	10.09952	10.20051	10.30252	10.40554	10.5096	10.61469	10.72084	10.82805	10.93633	11.04569	11.15615	11.26771	11.38039	11.49419	11.609132
Minden TS	230	3A Central	MINDEN	M3	11.792	11.90992	12.02902	12.14931	12.2708	12.39351	12.51745	12.64262	12.76905	12.89674	13.0257	13.15596	13.28752	13.4204	13.5546	13.69015	13.82705	13.96532	14.10497	14.24602	14.38848	14.532366
Morrisburg TS	115	4 East	WINCHESTER	M23	17.243	17.41543	17.58958	17.76548	17.94313	18.12257	18.30379	18.48683	18.6717	18.85842	19.047	19.23747	19.42984	19.62414	19.82038	20.01859	20.21877	20.42096	20.62517	20.83142	21.03974	21.250134
Morrisburg TS	115	4 East	WINCHESTER	M25	10.033	10.13333	10.23466	10.33701	10.44038	10.54478	10.65023	10.75673	10.8643	10.97294	11.08267	11.1935	11.30544	11.41849	11.53267	11.648	11.76448	11.88213	12.00095	12.12096	12.24217	12.364588
Morrisburg TS	115	4 East	WINCHESTER	M26	16.42	16.5842	16.75004	16.91754	17.08672	17.25759	17.43016	17.60446	17.78051	17.95831	18.1379	18.31927	18.50247	18.68749	18.87437	19.06311	19.25374	19.44628	19.64074	19.83715	20.03552	20.235876
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M1	14.376	14.51976	14.66496	14.81161	14.95972	15.10932	15.26041	15.41302	15.56715	15.72282	15.88005	16.03885	16.19924	16.36123	16.52484	16.69009	16.85699	17.02556	17.19582	17.36777	17.54145	17.716867
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M10	6.685	6.75185	6.819369	6.887562	6.956438	7.026002	7.096262	7.167225	7.238897	7.311286	7.384399	7.458243	7.532825	7.608154	7.684235	7.761077	7.838688	7.917075	7.996246	8.076208	8.15697	8.2385401
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M2	19.797	19.99497	20.19492	20.39687	20.60084	20.80685	21.01491	21.22506	21.43731	21.65169	21.8682	22.08689	22.30776	22.53083	22.75614	22.9837	23.21354	23.44567	23.68013	23.91693	24.1561	24.397663
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M3	11.108	11.21908	11.33127	11.44458	11.55903	11.67462	11.79137	11.90928	12.02837	12.14866	12.27014	12.39284	12.51677	12.64194	12.76836	12.89604	13.025	13.15525	13.28681	13.41967	13.55387	13.68941
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M4	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M7	13.041	13.17141	13.30312	13.43616	13.57052	13.70622	13.84328	13.98172	14.12153	14.26275	14.40538	14.54943	14.69493	14.84187	14.99029	15.1402	15.2916	15.44451	15.59896	15.75495	15.9125	16.071623
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M8	16.843	17.01143	17.18154	17.35336	17.52689	17.70216	17.87918	18.05798	18.23856	18.42094	18.60515	18.7912	18.97911	19.16891	19.36059	19.5542	19.74974	19.94724	20.14671	20.34818	20.55166	20.757177
Muskoka TS	230	5 Georgian	BRACEBRIDGE	M9	15	15.15	15.3015	15.45452	15.60906	15.76515	15.9228	16.08203	16.24285	16.40528	16.56933	16.73503	16.90238	17.0714	17.24211	17.41453	17.58868	17.76457	17.94221	18.12163	18.30285	18.485879
Napanee TS	230	3B East Ce	PICTON	M1	28.308	28.59108	28.87699	29.16576	29.45742	29.75199	30.04951	30.35001	30.65351	30.96004	31.26964	31.58234	31.89816	32.21714	32.53932	32.86471	33.19336	33.52529	33.86054	34.19915	34.54114	34.886551
Napanee TS	230	3B East Ce	PICTON	M2	28.646	28.93246	29.22178	29.514	29.80914	30.10723	30.40831	30.71239	31.01951	31.32971	31.64301	31.95944	32.27903	32.60182	32.92784	33.25712	33.58969	33.92558	34.26484	34.60749	34.95356	35.3031
Napanee TS	230	3B East Ce	PICTON	M3	14.928	15.07728	15.22805	15.38033	15.53414	15.68948	15.84637	16.00484	16.16488	16.32653	16.4898	16.6547	16.82124	16.98946	17.15935	17.33094	17.50425	17.6793	17.85609	18.03465	18.215	18.397147
Napanee TS	230	3B East Ce	PICTON	M4	14.236	14.37836	14.52214	14.66737	14.81404	14.96218	15.1118	15.26292	15.41555	15.5697	15.7254	15.88265	16.04148	16.2019	16.36391	16.52755	16.69283	16.85976	17.02836	17.19864	17.37063	17.544332
Orangeville TS	230	2 West Cer	ORANGEVILLE	M1	9.166	9.25766	9.350237	9.443739	9.538176	9.633558	9.729894	9.827193	9.925465	10.02472	10.12497	10.22622	10.32848	10.43176	10.53608	10.64144	10.74786	10.85533	10.96389	11.07353	11.18426	11.296105
Orangeville TS	230	2 West Cer	ORANGEVILLE	M2	4.793	4.84093	4.889339	4.938233	4.987615	5.037491	5.087866	5.138745	5.190132	5.242034	5.294454	5.347398	5.400872	5.454881	5.50943	5.564524	5.620169	5.676371	5.733135	5.790466	5.848371	5.9068546
Orangeville TS	230	2 West Cer	ORANGEVILLE	M3	10.285	10.38785	10.49173	10.59665	10.70261	10.80964	10.91773	11.02691	11.13718	11.24855	11.36104	11.47465	11.5894	11.70529	11.82234	11.94057	12.05997	12.18057	12.30238	12.4254	12.54965	12.675151
Orangeville TS	230	2 West Cer	ORANGEVILLE	M4	12.064	12.18464	12.30649	12.42955	12.55385	12.67939	12.80618	12.93424	13.06358	13.19422	13.32616	13.45942	13.59402	13.72996	13.86726	14.00593	14.14599	14.28745	14.43032	14.57463	14.72037	14.867576
Orangeville TS	230	2 West Cer	ORANGEVILLE	M45	9.526	9.62126	9.717473	9.814647	9.912794	10.01192	10.11204	10.21316	10.31529	10.41845	10.52263	10.62786	10.73414	10.84148	10.94989	11.05939	11.16998	11.28168	11.3945	11.50845	11.62353	11.739766
Orangeville TS	230	2 West Cer	ORANGEVILLE	M46	1.411	1.42511	1.439361	1.453755	1.468292	1.482975	1.497805	1.512783	1.527911	1.54319	1.558622	1.574208	1.58995	1.60585	1.621908	1.638127	1.654508	1.671054	1.687764	1.704642	1.721688	1.738905
Orangeville TS	230	2 West Cer	ORANGEVILLE	M5	15.103	15.25403	15.40657	15.56064	15.71624	15.8734	16.03214	16.19246	16.35438	16.51793	16.68311	16.84994	17.01844	17.18862	17.36051	17.53411	17.70946	17.88655	18.06542	18.24607	18.42853	18.612815
Orangeville TS	230	2 West Cer	ORANGEVILLE	M6	7.858	7.93658	8.015946	8.096105	8.177066	8.258837	8.341425	8.42484	8.509088	8.594179	8.680121	8.766922	8.854591	8.943137	9.032568	9.122894	9.214123	9.306264	9.399327	9.49332	9.588253	9.6841359
Orillia TS	230	5 Georgian	ORILLIA	M1	11.856	11.97456	12.09431	12.21525	12.3374	12.46078	12.58538	12.71124	12.83835	12.96673	13.0964	13.22736	13.35964	13.49323	13.62817	13.76445	13.90209	14.04111	14.18152	14.32334	14.46657	14.611239
Orillia TS	230	5 Georgian	ORILLIA	M2	14.874	15.02274	15.17297	15.3247	15.47794	15.63272	15.78905	15.94694	16.10641	16.26747	16.43015	16.59445	16.7604	16.928	17.09728	17.26825	17.44093	17.61534	17.7915	17.96941	18.14911	18.330598
Orillia TS	230	5 Georgian	ORILLIA	M3	5.818	5.87618	5.934942	5.994291	6.054234	6.114776	6.175924	6.237683	6.30006	6.363061	6.426692	6.490958	6.555868	6.621427	6.687641	6.754517	6.822063	6.890283	6.959186	7.028778	7.099066	7.1700563
Orillia TS	230	5 Georgian	ORILLIA	M4	14.874	15.02274	15.17297	15.3247	15.47794	15.63272	15.78905	15.94694	16.10641	16.26747	16.43015	16.59445	16.7604	16.928	17.09728	17.26825	17.44093	17.61534	17.7915	17.96941	18.14911	18.330598
Orillia TS	230	5 Georgian	ORILLIA	M5	9.382	9.47582	9.570578	9.666284	9.762947	9.860576	9.959182	10.05877	10.15936	10.26096	10.36356	10.4672	10.57187	10.67759	10.78437	10.89221	11.00113	11.11114	11.22226	11.33448	11.44782	11.562301

Orillia TS	230	5 Georgian	ORILLIA	M6	9.292	9.38492	9.478769	9.573557	9.669292	9.765985	9.863645	9.962282	10.0619	10.16252	10.26415	10.36679	10.47046	10.57516	10.68091	10.78772	10.8956	11.00456	11.1146	11.22575	11.33801	11.451386
Orillia TS	230	5 Georgian	ORILLIA	M7	14.129	14.27029	14.41299	14.55712	14.70269	14.84972	14.99822	15.1482	15.29968	15.45268	15.60721	15.76328	15.92091	16.08012	16.24092	16.40333	16.56736	16.73304	16.90037	17.06937	17.24007	17.412466
Orillia TS	230	5 Georgian	ORILLIA	M8	9.899	9.99799	10.09797	10.19895	10.30094	10.40395	10.50799	10.61307	10.7192	10.82639	10.93465	11.044	11.15444	11.26599	11.37865	11.49243	11.60736	11.72343	11.84066	11.95907	12.07866	12.199448
Otonabee TS	230	3A Central	PETERBOROUGI	M27	14.706	14.85306	15.00159	15.15161	15.30312	15.45615	15.61072	15.76682	15.92449	16.08374	16.24457	16.40702	16.57109	16.7368	16.90417	17.07321	17.24394	17.41638	17.59054	17.76645	17.94411	18.123556
Otonabee TS	230	3A Central	PETERBOROUGI	M28	14.98	15.1298	15.2811	15.43391	15.58825	15.74413	15.90157	16.06059	16.22119	16.38341	16.54724	16.71271	16.87984	17.04864	17.21912	17.39131	17.56523	17.74088	17.91829	18.09747	18.27845	18.461231
Owen Sound TS	230	5 Georgian	OWEN SOUND	M21	15.415	15.56915	15.72484	15.88209	16.04091	16.20132	16.36333	16.52697	16.69224	16.85916	17.02775	17.19803	17.37001	17.54371	17.71914	17.89634	18.0753	18.25605	18.43861	18.623	18.80923	18.997322
Owen Sound TS	230	5 Georgian	OWEN SOUND	M22	20	20.2	20.402	20.60602	20.81208	21.0202	21.2304	21.44271	21.65713	21.87371	22.09244	22.31337	22.5365	22.76187	22.98948	23.21938	23.45157	23.68609	23.92295	24.16218	24.4038	24.647839
Owen Sound TS	230	5 Georgian	OWEN SOUND	M23	9.332	9.42532	9.519573	9.614769	9.710917	9.808026	9.906106	10.00517	10.10522	10.20627	10.30833	10.41142	10.51553	10.62069	10.72689	10.83416	10.9425	11.05193	11.16245	11.27407	11.38681	11.500682
Owen Sound TS	230	5 Georgian	OWEN SOUND	M24	16.432	16.59632	16.76228	16.92991	17.09921	17.2702	17.4429	17.61733	17.7935	17.97144	18.15115	18.33266	18.51599	18.70115	18.88816	19.07704	19.26781	19.46049	19.6551	19.85165	20.05016	20.250664
Owen Sound TS	230	5 Georgian	OWEN SOUND	M25	14.631	14.77731	14.92508	15.07433	15.22508	15.37733	15.5311	15.68641	15.84328	16.00171	16.16173	16.32334	16.48658	16.65144	16.81796	16.98614	17.156	17.32756	17.50083	17.67584	17.8526	18.031126
Owen Sound TS	230	5 Georgian	OWEN SOUND	M26	22.168	22.38968	22.61358	22.83971	23.06811	23.29879	23.53178	23.7671	24.00477	24.24482	24.48726	24.73214	24.97946	25.22925	25.48154	25.73636	25.99372	26.25366	26.5162	26.78136	27.04917	27.319665
Owen Sound TS	230	5 Georgian	OWEN SOUND	M28	6.005	6.06505	6.125701	6.186958	6.248827	6.311315	6.374429	6.438173	6.502555	6.56758	6.633256	6.699588	6.766584	6.83425	6.902593	6.971619	7.041335	7.111748	7.182866	7.254694	7.327241	7.4005136
Palmerston TS	115	1 West	LISTOWEL	M1	15.608	15.76408	15.92172	16.08094	16.24175	16.40416	16.56821	16.73389	16.90123	17.07024	17.24094	17.41335	17.58749	17.76336	17.94099	18.1204	18.30161	18.48462	18.66947	18.85616	19.04473	19.235173
Palmerston TS	115	1 West	LISTOWEL	M2	10.878	10.98678	11.09665	11.20761	11.31969	11.43289	11.54722	11.66269	11.77932	11.89711	12.01608	12.13624	12.2576	12.38018	12.50398	12.62902	12.75531	12.88286	13.01169	13.14181	13.27323	13.40596
Palmerston TS	115	1 West	LISTOWEL	M3	11.243	11.35543	11.46898	11.58367	11.69951	11.81651	11.93467	12.05402	12.17456	12.2963	12.41927	12.54346	12.66889	12.79558	12.92354	13.05277	13.1833	13.31513	13.44829	13.58277	13.7186	13.855783
Palmerston TS	115	1 West	LISTOWEL	M4	10.965	11.07465	11.1854	11.29725	11.41022	11.52433	11.63957	11.75596	11.87352	11.99226	12.11218	12.2333	12.35564	12.47919	12.60398	12.73002	12.85732	12.9859	13.11576	13.24691	13.37938	13.513178
Parry Sound TS	230	5 Georgian	PARRY SOUND	M1	8.307	8.39007	8.473971	8.55871	8.644298	8.73074	8.818048	8.906228	8.995291	9.085244	9.176096	9.267857	9.360536	9.454141	9.548682	9.644169	9.740611	9.838017	9.936397	10.03576	10.13612	10.23748
Parry Sound TS	230	5 Georgian	PARRY SOUND	M2	9.177	9.26877	9.361458	9.455072	9.549623	9.645119	9.74157	9.838986	9.937376	10.03675	10.13712	10.23849	10.34087	10.44428	10.54872	10.65421	10.76075	10.86836	10.97705	11.08682	11.19768	11.309661
Parry Sound TS	230	5 Georgian	PARRY SOUND	M4	6.694	6.76094	6.828549	6.896835	6.965803	7.035461	7.105816	7.176874	7.248643	7.321129	7.394341	7.468284	7.542967	7.618396	7.69458	7.771526	7.849241	7.927734	8.007011	8.087081	8.167952	8.2496316
Pembroke TS	115	3B East Ce	COBDEN	M1	16.987	17.15687	17.32844	17.50172	17.67674	17.85351	18.03204	18.21236	18.39449	18.57843	18.76422	18.95186	19.14138	19.33279	19.52612	19.72138	19.91859	20.11778	20.31896	20.52215	20.72737	20.934642
Pembroke TS	115	3B East Ce	COBDEN	M2	5.359	5.41259	5.466716	5.521383	5.576597	5.632363	5.688686	5.745573	5.803029	5.861059	5.91967	5.978867	6.038655	6.099042	6.160032	6.221633	6.283849	6.346687	6.410154	6.474256	6.538998	6.6043884
Pembroke TS	115	3B East Ce	COBDEN	M3	0.67	0.6767	0.683467	0.690302	0.697205	0.704177	0.711219	0.718331	0.725514	0.732769	0.740097	0.747498	0.754973	0.762522	0.770148	0.777849	0.785628	0.793484	0.801419	0.809433	0.817527	0.8257026
Picton TS	230	3B East Ce	PICTON	M5	16.086	16.24686	16.40933	16.57342	16.73916	16.90655	17.07561	17.24637	17.41883	17.59302	17.76895	17.94664	18.12611	18.30737	18.49044	18.67535	18.8621	19.05072	19.24123	19.43364	19.62798	19.824257
Picton TS	230	3B East Ce	PICTON	M6	7.58	7.6558	7.732358	7.809682	7.887778	7.966656	8.046323	8.126786	8.208054	8.290134	8.373036	8.456766	8.541334	8.626747	8.713015	8.800145	8.888146	8.977028	9.066798	9.157466	9.249041	9.3415309
Picton TS	230	3B East Ce	PICTON	M7	13.09	13.2209	13.35311	13.48664	13.62151	13.75772	13.8953	14.03425	14.17459	14.31634	14.4595	14.6041	14.75014	14.89764	15.04662	15.19708	15.34905	15.50255	15.65757	15.81415	15.97229	16.13201
Picton TS	230	3B East Ce	PICTON	M8	12.84	12.9684	13.09808	13.22906	13.36136	13.49497	13.62992	13.76622	13.90388	14.04292	14.18335	14.32518	14.46843	14.61312	14.75925	14.90684	15.05591	15.20647	15.35853	15.51212	15.66724	15.823913
Pleasant TS	230	2 West Ce	GUELPH*	M23	24.296	24.53896	24.78435	25.03219	25.28252	25.53534	25.79069	26.0486	26.30909	26.57218	26.8379	27.10628	27.37734	27.65111	27.92763	28.2069	28.48897	28.77386	29.0616	29.35222	29.64574	29.942195
Pleasant TS	230	2 West Ce	GUELPH*	M25	17.516	17.69116	17.86807	18.04675	18.22722	18.40949	18.59359	18.77952	18.96732	19.15699	19.34856	19.54205	19.73747	19.93484	20.13419	20.33553	20.53889	20.74428	20.95172	21.16124	21.37285	21.586577
Pleasant TS	230	2 West Ce	GUELPH*	M26	17.901	18.08001	18.26081	18.44342	18.62785	18.81413	19.00227	19.19229	19.38422	19.57806	19.77384	19.97158	20.17129	20.37301	20.57674	20.78251	20.99033	21.20023	21.41224	21.62636	21.84262	22.061048
Pleasant TS	230	2 West Ce	GUELPH*	M28	20.595	20.80095	21.00896	21.21905	21.43124	21.64555	21.86201	22.08063	22.30143	22.52445	22.74969	22.97719	23.20696	23.43903	23.67342	23.91016	24.14926	24.39075	24.63466	24.881	25.12981	25.381112
Port Hope TS	115	3A Central	PETERBOROUGI	M1	8.807	8.89507	8.984021	9.073861	9.1646	9.256246	9.348808	9.442296	9.536719	9.632086	9.728407	9.825691	9.923948	10.02319	10.12342	10.22465	10.3269	10.43017	10.53447	10.63982	10.74621	10.853676
Port Hope TS	115	3A Central	PETERBOROUGI	M15	6.958	7.02758	7.097856	7.168834	7.240523	7.312928	7.386057	7.459918	7.534517	7.609862	7.685961	7.76282	7.840449	7.918853	7.998042	8.078022	8.158802	8.24039	8.322794	8.406022	8.490082	8.5749831
Port Hope TS	115	3A Central	PETERBOROUGI	M16	12.492	12.61692	12.74309	12.87052	12.99923	13.12922	13.26051	13.39311	13.52705	13.66232	13.79894	13.93693	14.0763	14.21706	14.35923	14.50282	14.64785	14.79433	14.94227	15.0917	15.24261	15.39504
Port Hope TS	115	3A Central	PETERBOROUGI	M17	7.912	7.99112	8.071031	8.151742	8.233259	8.315592	8.398747	8.482735	8.567562	8.653238	8.73977	8.827168	8.91544	9.004594	9.09464	9.185586	9.277442	9.370217	9.463919	9.558558	9.654144	9.750685
Port Hope TS	115	3A Central	PETERBOROUGI	M18	5.323	5.37623	5.429992	5.484292	5.539135	5.594526	5.650472	5.706976	5.764046	5.821687	5.879904	5.938703	5.99809	6.058071	6.118651	6.179838	6.241636	6.304052	6.367093	6.430764	6.495072	6.5600223
Port Hope TS	115	3A Central	PETERBOROUGI	M2	14.321	14.46421	14.60885	14.75494	14.90249	15.05151	15.20203	15.35405	15.50759	15.66267	15.81929	15.97749	16.13726	16.29863	16.46162	16.62624	16.7925	16.96042	17.13003	17.30133	17.47434	17.649085
Port Hope TS	115	3A Central	PETERBOROUGI	M3	12.154	12.27554	12.3983	12.52228	12.6475	12.77398	12.90172	13.03073	13.16104	13.29265	13.42558	13.55983	13.69543	13.83239	13.97071	14.11042	14.25152	14.39404	14.53798	14.68336	14.83019	14.978492
Port Hope TS	115	3A Central	PETERBOROUGI	M4	14.025	14.16525	14.3069	14.44997	14.59447	14.74042	14.88782	15.0367	15.18707	15.33894	15.49233	15.64725	15.80372	15.96176	16.12138	16.28259	16.44542	16.60987	16.77597	16.94373	17.11317	17.284297
Red Lake TS	115	7 Northwes	DRYDEN	M4	6.798	6.86598	6.93464	7.003986	7.074026	7.144766	7.216214	7.288376	7.36126	7.434872	7.509221	7.584313	7.660157	7.736758	7.814126	7.892267	7.97119	8.050902	8.131411	8.212725	8.294852	8.3778004
Red Lake TS	115	7 Northwes	DRYDEN	M6	23.093	23.32393	23.55717	23.79274	24.03067	24.27098	24.51368	24.75882	25.00641	25.25647	25.50904	25.76413	26.02177	26.28199	26.54481	26.81026	27.07836	27.34914	27.62263	27.89886	28.17785	28.459627
Sidney TS	115	3B East Ce	TRENTON	M1	-9.561	-9.65661	-9.75318	-9.85071	-9.94921	-10.0487	-10.1492	-10.2507	-10.3532	-10.4567	-10.5613	-10.6669	-10.7736	-10.8813	-10.9901	-11.1	-11.211	-11.3231	-11.4364	-11.5507	-11.6662	-11.782899
Sidney TS	115	3B East Ce	TRENTON	M3	10.408	10.51208	10.6172	10.72337	10.83061	10.93891	11.0483	11.15878	11.27037	11.38308	11.49691	11.61188	11.72799	11.84527	11.96373	12.08336	12.2042	12.32624	12.4495	12.574	12.69974	12.826735
Sidney TS	115	3B East Ce	TRENTON	M4	18.304	18.48704	18.67191	18.85863	19.04722	19.23769	19.43006	19.62437	19.82061	20.01882	20.219	20.42119	20.62541	20.83166	21.03998	21.25038	21.46288	21.67751	21.89428	22.11323	22.33436	22.557702
Sidney TS	115	3B East Ce	TRENTON	M5	15.33	15.4833	15.63813	15.79451	15.95246	16.11198	16.2731	16.43583	16.60019	16.7662	16.93386	17.1032	17.27423	17.44697	17.62144	17.79765	17.97563	18.15539	18.33694	18.52031	18.70551	18.892568
Sidney TS	115	3B East Ce	TRENTON	M6	3.748	3.78548	3.823335	3.861568	3.900184	3.939186	3.978578	4.018363	4.058547	4.099132	4.140124	4.181525	4.22334	4.265574	4.308229	4.351312	4.394825	4.438773	4.483161	4.527992	4.573272	4.619005
Sidney TS	115	3B East Ce	TRENTON	M7	7.84	7.9184	7.997584	8.07756	8.158335	8.239919	8.322318	8.405541	8.489597	8.574493	8.660237	8.74684	8.834308	8.922651	9.011878	9.101997	9.193017	9.284947	9.377796	9.471574	9.56629	9.6619528
Sidney TS	115	3B East Ce	TRENTON	R8S	7.693	7.76993	7.847629	7.926106	8.005367	8.08542	8.166275	8.247937	8.330417	8.413721	8.497858	8.582837	8.668665	8.755352	8.842905	8.931334	9.020648	9.110854	9.201963	9.293982	9.386922	9.4807912
Sidney TS	115	3B East Ce	TRENTON	R9S	-8.231	-8.31331	-8.39644	-8.48041	-8.56521	-8.65086	-8.73737	-8.82475	-8.91299	-9.00212	-9.09214	-9.18307	-9.2749	-9.36765	-9.46132	-9.55594	-9.65149	-9.74801	-9.84549	-9.94394	-10.0434	-10.143818
Smiths Falls TS	230	4 East	PERTH	M21	8.17	8.2517	8.334217	8.417559	8.501735	8.586752	8.67262	8.759346	8.846939	8.935409	9.024763	9.11501	9.20616	9.298222	9.391204	9.485116	9.579968	9.675767	9.772525	9.87025	9.968953	10.068642
Smiths Falls TS	230	4 East	PERTH	M22	2.483	2.50783	2.532908	2.558237	2.58382	2.609658	2.635755	2.662112	2.688733	2.715621	2.742777	2.770205	2.797907	2.825886	2.854144	2.882686	2.911513	2.940628	2.970034	2.999735	3.029732	3.0600292
Smiths Falls TS	230	4 East	PERTH	M23	11.428	11.54228	11.6577	11.77428	11.89202	12.01094	12.13105	12.25236	12.37489	12.49864	12.62362	12.74986	12.87736	13.00613	13.13619	13.26755	13.40023	13.53423	13.66957	13.80627	13.94433	14.083775
Smiths Falls TS	230	4 East	PERTH	M24	3.74	3.7774	3.815174	3.853326	3.891859	3.930778	3.970085	4.009786	4.049884	4.090383	4.131287	4.1726	4.214326	4.256469	4.299034	4.342024	4.385444	4.429299	4.473592	4.518327	4.563511	4.6091459
Smiths Falls TS	230	4 East	PERTH	M25	15.372	15.52572	15.68098	15.83779	15.99616	16.15613	16.31769	16.48086	16.64567	16.81213	16.98025	17.15005	17.32155	17.49477	17.66972	17.84641	18.02488	18.20513	18.38718	18.57105	18.75676	18.944329
Smiths Falls TS	230	4 East	PERTH	M26	11.835	11.95335	12.07288	12.19361	12.31555	12.4387	12.56309	12.68872	12.81561	12.94377	13.0732	13.20393	13.33597	13.46933	13.60403	13.74007	13.87747	14.01624	14.15641	14.29797	14.44095	14.585359
Smiths Falls TS	230	4 East	PERTH	M28	1.682	1.69882	1.715808	1.732966	1.750296	1.767799	1.785477	1.803332	1.821365	1.839579	1.857974	1.876554	1.89532	1.914273	1.933416	1.95275	1.972277	1.992	2.01192	2.032039	2.05236	2.0728832
South March TS	230	4 East	ARNPRIOR	M3	8.441	8.52541	8.610664	8.696771	8.783738	8.871576	8.960292	9.049895	9.140393	9.231797	9.324115	9.417357	9.51153	9.606645	9.702712	9.799739	9.897736	9.996714	10.09668	10.19765	10.29962	10.40262
South March TS	230	4 East	ARNPRIOR	M5	19.08	19.2708	19.46351	19.65814	19.85472	20.05327	20.2538	20.45634	20.66091	20.86752	21.07619	21.28695	21.49982	21.71482	21.93197	22.15129	22.3728	22.59653	22.82249	23.05072	23.28123	23.514038
St.Isidore TS	230	4 East	VANKLEEK HILL	M1	5.017	5.06717	5.117842	5.16902	5.22071	5.272917	5.325647	5.378903	5.432692	5.487019	5.541889	5.597308	5.653281	5.709814	5.766912	5.824581	5.882827	5.941655	6.001072	6.061083	6.121693	6.1829104
St.Isidore TS	230	4 East	VANKLEEK HILL	M2	10.426	10.53026	10.63556	10.74192	10.84934	10.95783	11.06741	11.17808	11.28986	11.40276	11.51679	11.63196	11.74828	11.86576	11.98442	12.10426	12.2253	12.34756	12.47103	12.59574	12.7217	12.848918
St.Isidore TS	230	4 East	VANKLEEK HILL	M3	2.643	2.66943	2.696124	2.723086	2.750316	2.77782	2.805598	2.833654	2.86199	2.890061	2.919516	2.948711	2.978199	3.007981	3.03806	3.068441	3.099125	3.130117	3.161418	3.193032	3.224962	3.2572119
St.Isidore TS	230	4 East	VANKLEEK HILL	M4	13.526	13.66126	13.79787	13.93585	14.07521	14.21596	14.35812	14.5017	14.64672	14.79319	14.94112	15.09053	15.24144	15.39385	15.54779	15.70327	15.8603	16.0189	16.17909	16.34088	16.50429	16.669333
St.Lawrence TS	230	4 East	WINCHESTER	M24	2.758	2.78558	2.813436	2.84157	2.869986	2.898686	2.927673	2.956949	2.986519	3.016384	3.046548	3.077013	3.107783	3.138861	3.17025	3.201952	3.233972	3.266312	3.298975	3.331964	3.365284	3.398937
St.Lawrence TS	230	4 East	WINCHESTER	M25	8.478	8.56278	8.648408	8.734892	8.822241	8.910463	8.999568	9.089564	9.180459	9.272264	9.364986	9.458636	9.553223	9.648755	9.745242	9.842695	9.941122	10.04053	10.14094	10.24235	10.34477	10.448219
St.Lawrence TS	230	4 East	WINCHESTER	M26	9.685	9.78185	9.879669	9.978465	10.07825	10.17903	10.28082	10.38363	10.48747	10.59234	10.69827	10.80525	10.9133	11.02243	11.13266	11.24398	11.35642	11.46999	11.58469	11.70054	11.81754	11.935716
St.Lawrence TS	230	4 East	WINCHESTER	M27	0.682	0.68882	0.695708	0.702665	0.709692	0.716789	0.723957	0.731196	0.738508	0.745893	0.753352	0.760886	0.768495	0.77618	0.783941	0.791781	0.799699	0.807696	0.815773	0.82393	0.83217	0.8404913
St.Lawrence TS	230	4 East	WINCHESTER	M28	-0.011	-0.01111	-0.01122	-0.01133	-0.01145	-0.01156	-0.01168	-0.01179	-0.01191	-0.01203	-0.01215	-0.01227	-0.0124	-0.01252	-0.01264	-0.01277	-0.0129	-0.01303	-0.01316	-0.01329	-0.01342	-0.0135563
Stayner TS	230	5 Georgian	BARRIE	M1	5.353	5.40653	5.460595	5.515201	5.570353	5.626057	5.682317	5.739141	5.796532	5.854497	5.913042	5.972173	6.031894	6.092213	6.153135	6.214667	6.276813	6.339582	6.402977	6.467007	6.531677	6.5969941

Stayner TS	230	5 Georgian	BARRIE	M2	13.164	13.29564	13.4286	13.56288	13.69851	13.8355	13.97385	14.11359	14.25473	14.39727	14.54125	14.68666	14.83352	14.98186	15.13168	15.283	15.43583	15.59018	15.74609	15.90355	16.06258	16.223208
Stayner TS	230	5 Georgian	BARRIE	M3	0.021	0.02121	0.021422	0.021636	0.021853	0.022071	0.022292	0.022515	0.02274	0.022967	0.023197	0.023429	0.023663	0.0239	0.024139	0.02438	0.024624	0.02487	0.025119	0.02537	0.025624	0.0258802
Stayner TS	230	5 Georgian	BARRIE	M4	24.486	24.73086	24.97817	25.22795	25.48023	25.73503	25.99238	26.25231	26.51483	26.77998	27.04778	27.31826	27.59144	27.86735	28.14603	28.42749	28.71176	28.99888	29.28887	29.58176	29.87757	30.176349
Stayner TS	230	5 Georgian	BARRIE	M5	0.021	0.02121	0.021422	0.021636	0.021853	0.022071	0.022292	0.022515	0.02274	0.022967	0.023197	0.023429	0.023663	0.0239	0.024139	0.02438	0.024624	0.02487	0.025119	0.02537	0.025624	0.0258802
Stewartville TS	115	4 East	ARNPRIOR	M1	5.319	5.37219	5.425912	5.480171	5.534973	5.590322	5.646226	5.702688	5.759715	5.817312	5.875485	5.93424	5.993582	6.053518	6.114053	6.175194	6.236946	6.299315	6.362308	6.425932	6.490191	6.5550927
Stewartville TS	115	4 East	ARNPRIOR	M3	13.143	13.27443	13.40717	13.54125	13.67666	13.81343	13.95156	14.09107	14.23199	14.37431	14.51805	14.66323	14.80986	14.95796	15.10754	15.25861	15.4112	15.56531	15.72097	15.87818	16.03696	16.197327
Thornton TS	230	3A Central	BOWMANVILLE	M1	3.565	3.60065	3.636657	3.673023	3.709753	3.746851	3.784319	3.822163	3.860384	3.898988	3.937978	3.977358	4.017131	4.057303	4.097876	4.138854	4.180243	4.222045	4.264266	4.306908	4.349977	4.3934773
Thornton TS	230	3A Central	BOWMANVILLE	M6	11.825	11.94325	12.06268	12.18331	12.30514	12.42819	12.55248	12.678	12.80478	12.93283	13.06216	13.19278	13.32471	13.45795	13.59253	13.72846	13.86574	14.0044	14.14444	14.28589	14.42875	14.573035
Thornton TS	230	3A Central	BOWMANVILLE	M7	6.914	6.98314	7.052971	7.123501	7.194736	7.266683	7.33935	7.412744	7.486871	7.56174	7.637357	7.713731	7.790868	7.868777	7.947465	8.026939	8.107209	8.188281	8.270164	8.352865	8.436394	8.5207579
Thornton TS	230	3A Central	BOWMANVILLE	M8	11.6	11.716	11.83316	11.95149	12.07101	12.19172	12.31363	12.43677	12.56114	12.68675	12.81362	12.94175	13.07117	13.20188	13.3339	13.46724	13.60191	13.73793	13.87531	14.01406	14.1542	14.295747
Trout Lake TS	230	6 Northeas	NIPISSING	M3	9.923	10.02223	10.12245	10.22368	10.32591	10.42917	10.53346	10.6388	10.74519	10.85264	10.96117	11.07078	11.18148	11.2933	11.40623	11.52029	11.6355	11.75185	11.86937	11.98807	12.10795	12.229025
Trout Lake TS	230	6 Northeas	NIPISSING	M7	7.819	7.89719	7.976162	8.055924	8.136483	8.217848	8.300026	8.383026	8.466857	8.551525	8.63704	8.723411	8.810645	8.898751	8.987739	9.077616	9.168392	9.260076	9.352677	9.446204	9.540666	9.6360726
Trout Lake TS	230	6 Northeas	NIPISSING	M8	9.577	9.67277	9.769498	9.867193	9.965865	10.06552	10.16618	10.26784	10.37052	10.47422	10.57897	10.68476	10.7916	10.89952	11.00851	11.1186	11.22979	11.34208	11.4555	11.57006	11.68576	11.802618
Wallace TS	230	3B East Ce	BANCROFT	16M1	10.749	10.85649	10.96505	11.07471	11.18545	11.29731	11.41028	11.52438	11.63963	11.75602	11.87358	11.99232	12.11224	12.23336	12.3557	12.47926	12.60405	12.73009	12.85739	12.98596	13.11582	13.246981
Wallace TS	230	3B East Ce	BANCROFT	16M4	9.685	9.78185	9.879669	9.978465	10.07825	10.17903	10.28082	10.38363	10.48747	10.59234	10.69827	10.80525	10.9133	11.02243	11.13266	11.24398	11.35642	11.46999	11.58469	11.70054	11.81754	11.935716
Wallace TS	230	3B East Ce	BANCROFT	16M6	10.442	10.54642	10.65188	10.7584	10.86599	10.97465	11.08439	11.19524	11.30719	11.42026	11.53446	11.64981	11.76631	11.88397	12.00281	12.12284	12.24407	12.36651	12.49017	12.61507	12.74122	12.868637
Waubaushene TS	230	5 Georgian	PENETANG	M1	11.379	11.49279	11.60772	11.7238	11.84103	11.95944	12.07904	12.19983	12.32183	12.44504	12.5695	12.69519	12.82214	12.95036	13.07987	13.21067	13.34277	13.4762	13.61096	13.74707	13.88454	14.023388
Waubaushene TS	230	5 Georgian	PENETANG	M2	16.44	16.6044	16.77044	16.93815	17.10753	17.27861	17.45139	17.62591	17.80216	17.98019	18.15999	18.34159	18.525	18.71025	18.89736	19.08633	19.27719	19.46996	19.66466	19.86131	20.05992	20.260523
Waubaushene TS	230	5 Georgian	PENETANG	M3	13.094	13.22494	13.35719	13.49076	13.62567	13.76193	13.89954	14.03854	14.17893	14.32071	14.46392	14.60856	14.75465	14.90219	15.05122	15.20173	15.35374	15.50728	15.66236	15.81898	15.97717	16.13694
Waubaushene TS	230	5 Georgian	PENETANG	M4	12.483	12.60783	12.73391	12.86125	12.98986	13.11976	13.25096	13.38347	13.5173	13.65247	13.789	13.92689	14.06616	14.20682	14.34889	14.49238	14.6373	14.78367	14.93151	15.08082	15.23163	15.383949
Waubaushene TS	230	5 Georgian	PENETANG	M5	11.998	12.11798	12.23916	12.36155	12.48517	12.61002	12.73612	12.86348	12.99211	13.12204	13.25326	13.38579	13.51965	13.65484	13.79139	13.92931	14.0686	14.20928	14.35138	14.49489	14.63984	14.786239
Waubaushene TS	230	5 Georgian	PENETANG	M6	3.031	3.06131	3.091923	3.122842	3.154071	3.185611	3.217468	3.249642	3.282139	3.31496	3.34811	3.381591	3.415407	3.449561	3.484056	3.518897	3.554086	3.589627	3.625523	3.661778	3.698396	3.73538
Waubaushene TS	230	5 Georgian	PENETANG	M7	9.904	10.00304	10.10307	10.2041	10.30614	10.4092	10.5133	10.61843	10.72461	10.83186	10.94018	11.04958	11.16008	11.27168	11.38439	11.49824	11.61322	11.72935	11.84664	11.96511	12.08476	12.20561
Whitby TS	230	3A Central	BOWMANVILLE	M22	19.37	19.5637	19.75934	19.95693	20.1565	20.35806	20.56165	20.76726	20.97493	21.18468	21.39653	21.6105	21.8266	22.04487	22.26532	22.48797	22.71285	22.93998	23.16938	23.40107	23.63508	23.871432
Wilson TS	230	3A Central	BOWMANVILLE	M11	24.486	24.73086	24.97817	25.22795	25.48023	25.73503	25.99238	26.25231	26.51483	26.77998	27.04778	27.31826	27.59144	27.86735	28.14603	28.42749	28.71176	28.99888	29.28887	29.58176	29.87757	30.176349
Wilson TS	230	3A Central	BOWMANVILLE	M12	22.145	22.36645	22.59011	22.81602	23.04418	23.27462	23.50736	23.74244	23.97986	24.21966	24.46186	24.70648	24.95354	25.20308	25.45511	25.70966	25.96675	26.22642	26.48869	26.75357	27.02111	27.29132
Wilson TS	230	3A Central	BOWMANVILLE	M13	8.596	8.68196	8.76878	8.856467	8.945032	9.034482	9.124827	9.216075	9.308236	9.401319	9.495332	9.590285	9.686188	9.78305	9.88088	9.979689	10.07949	10.18028	10.28208	10.3849	10.48875	10.593641
Wilson TS	230	3A Central	BOWMANVILLE	M14	8.898	8.98698	9.07685	9.167618	9.259294	9.351887	9.445406	9.53986	9.635259	9.731612	9.828928	9.927217	10.02649	10.12675	10.22802	10.3303	10.4336	10.53794	10.64332	10.74975	10.85725	10.965823
Wilson TS	230	3A Central	BOWMANVILLE	M15	18.396	18.57996	18.76576	18.95342	19.14295	19.33438	19.52772	19.723	19.92023	20.11943	20.32063	20.52383	20.72907	20.93636	21.14573	21.35718	21.57076	21.78646	22.00433	22.22437	22.44662	22.671082
Wilson TS	230	3A Central	BOWMANVILLE	M16	12.415	12.53915	12.66454	12.79119	12.9191	13.04829	13.17877	13.31056	13.44367	13.5781	13.71388	13.85102	13.98953	14.12943	14.27072	14.41343	14.55756	14.70314	14.85017	14.99867	15.14866	15.300146
Wilson TS	230	3A Central	BOWMANVILLE	M17	27.545	27.82045	28.09865	28.37964	28.66344	28.95007	29.23957	29.53197	29.82729	30.12556	30.42682	30.73108	31.0384	31.34878	31.66227	31.97889	32.29868	32.62167	32.94788	33.27736	33.61013	33.946236
Wilson TS	230	3A Central	BOWMANVILLE	M8	28.19	28.4719	28.75662	29.04419	29.33463	29.62797	29.92425	30.2235	30.52573	30.83099	31.1393	31.45069	31.7652	32.08285	32.40368	32.72771	33.05499	33.38554	33.7194	34.05659	34.39716	34.741129
Wingham TS	230	1 West	WALKERTON	M3	12.341	12.46441	12.58905	12.71494	12.84209	12.97052	13.10022	13.23122	13.36353	13.49717	13.63214	13.76846	13.90615	14.04521	14.18566	14.32752	14.47079	14.6155	14.76166	14.90927	15.05837	15.208949
Wingham TS	230	1 West	WALKERTON	M4	4.208	4.25008	4.292581	4.335507	4.378862	4.42265	4.466877	4.511546	4.556661	4.602228	4.64825	4.694732	4.74168	4.789097	4.836987	4.885357	4.934211	4.983553	5.033389	5.083722	5.13456	5.1859053
Wingham TS	230	1 West	WALKERTON	M5	12.127	12.24827	12.37075	12.49446	12.6194	12.7456	12.87305	13.00179	13.1318	13.26312	13.39575	13.52971	13.66501	13.80166	13.93967	14.07907	14.21986	14.36206	14.50568	14.65074	14.79724	14.945217
Wingham TS	230	1 West	WALKERTON	M6	15.13	15.2813	15.43411	15.58845	15.74434	15.90178	16.0608	16.22141	16.38362	16.54746	16.71293	16.88006	17.04886	17.21935	17.39154	17.56546	17.74111	17.91853	18.09771	18.27869	18.46148	18.64609
Woodbridge TS	230	3A Central	NEWMARKET*	M12	21	21.21	21.4221	21.63632	21.85268	22.07121	22.29192	22.51484	22.73999	22.96739	23.19706	23.42904	23.66333	23.89996	24.13896	24.38035	24.62415	24.87039	25.1191	25.37029	25.62399	25.880231
Woodbridge TS	230	3A Central	NEWMARKET*	M14	14.706	14.85306	15.00159	15.15161	15.30312	15.45615	15.61072	15.76682	15.92449	16.08374	16.24457	16.40702	16.57109	16.7368	16.90417	17.07321	17.24394	17.41638	17.59054	17.76645	17.94411	18.123556
Woodbridge TS	230	3A Central	NEWMARKET*	M16	12.022	12.14222	12.26364	12.38628	12.51014	12.63524	12.7616	12.88921	13.0181	13.14828	13.27977	13.41256	13.54669	13.68216	13.81898	13.95717	14.09674	14.23771	14.38008	14.52389	14.66912	14.815816

Financial Evaluation Summary - Alt. 1

Plan 0

0

Study Period - No. of Years 60

0

(A) Discounted Cash Flows (Note 1) $K

	Total	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Incremental Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental OM&A (Costs) / Cost Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Ontario Capital Tax and Municipal Tax	(1,447)	0	0	(6)	(12)	(16)	(19)	(22)	(26)	(29)	(32)	(35)	(37)	(44)	(43)	(43)	(42)	(41)	(44)	(44)	(47)	(48)	(47)	(45)
Operating Cash Flows	**(1,447)**	**0**	**0**	**(6)**	**(12)**	**(16)**	**(19)**	**(22)**	**(26)**	**(29)**	**(32)**	**(35)**	**(37)**	**(44)**	**(43)**	**(43)**	**(42)**	**(41)**	**(44)**	**(44)**	**(47)**	**(48)**	**(47)**	**(45)**
Income Tax Recovery/(Provision)	463	0	0	2	4	5	6	7	8	9	10	11	12	14	14	14	13	13	14	14	15	15	15	15
Net Operating Cash Flows	**(984)**	**0**	**0**	**(4)**	**(8)**	**(11)**	**(13)**	**(15)**	**(17)**	**(19)**	**(22)**	**(24)**	**(25)**	**(30)**	**(29)**	**(29)**	**(29)**	**(28)**	**(30)**	**(30)**	**(32)**	**(33)**	**(32)**	**(31)**
Capital Expenditures	**(49,500)**	**0**	**0**	**(4,500)**	**(4,500)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(3,000)**	**(6,000)**	**0**	**(1,500)**	**0**	**0**	**(3,000)**	**(1,500)**	**(3,000)**	**(1,500)**	**0**	**0**
CCA Tax Shield	14,637	0	0	58	168	251	307	360	408	452	493	530	564	634	660	627	596	548	543	557	570	582	555	510
Proceeds on disposal of depreciable property	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Change in Working Capital	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Project Terminal Value/Commitment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Cash Flows	**(35,847)**	**0**	**0**	**(4,447)**	**(4,340)**	**(2,760)**	**(2,705)**	**(2,655)**	**(2,610)**	**(2,568)**	**(2,529)**	**(2,494)**	**(2,461)**	**(5,396)**	**631**	**(903)**	**567**	**521**	**(2,487)**	**(973)**	**(2,462)**	**(951)**	**523**	**479**
Discount Factor @ **5.73%**		0.9458	0.8946	0.8461	0.8003	0.7570	0.7159	0.6772	0.6405	0.6058	0.5730	0.5419	0.5126	0.4848	0.4586	0.4337	0.4102	0.3880	0.3670	0.3471	0.3283	0.3105	0.2937	0.2778
Net Present Value (Discounted Cash Flows)	0	0	0	(3,762)	(3,473)	(2,089)	(1,937)	(1,798)	(1,671)	(1,555)	(1,449)	(1,351)	(1,262)	(2,616)	290	(391)	233	202	(913)	(338)	(808)	(295)	154	133
Cum. Net Present Value **(23,837)**		**0**	**0**	**(3,762)**	**(7,236)**	**(9,325)**	**(11,262)**	**(13,060)**	**(14,731)**	**(16,287)**	**(17,736)**	**(19,087)**	**(20,349)**	**(22,965)**	**(22,675)**	**(23,067)**	**(22,834)**	**(22,632)**	**(23,544)**	**(23,882)**	**(24,691)**	**(24,986)**	**(24,832)**	**(24,699)**

Note 1: Information in Section A is presented using cash flow conventions - positive amounts for cash inflows and negative amounts for cash outflows.

(B) NPV Summary and Profitability Index (Note 2) $K

A. PV - Revenue	**-**
B. PV - Incremental OM&A (Costs) / Cost Savings	**-**
C. PV - Ontario Capital Tax and Municipal Tax	**(485)**
D. PV - Taxes	**155**
E. PV - CCA Tax Shield	**5,585**
F. PV - Proceeds on disposal of depreciable property	**-**
G. PV - Change in Working capital	**-**
H. PV - Project Terminal value / (commitment)	**20**
I. Sub-total of above **(A+B+C+D+E+F+G+H)**	**5,275**
J. PV - Capital Expenditures	**(29,112)**
Cum. Net Present Value	**(23,837)**
Profitability Index (PI) = I/(J*-1)	**0.18** (for value enhancing projects, PI should be >= **1.1**)

Note 2: Information in Section B is presented using cash flow conventions - positive amounts for cash inflows and negative amounts for cash outflows.

(D) Other Financial Measurements

(1) **After-Tax IRR for this Alternative** - % **#DIV/0!**
(Please note: if the above result is #DIV/0! or #NUM!, it is not an error; it means that the project IRR cannot be computed with the given cash flows.)

(2) **Payback** (discounted) - No. of Years **N/A**
(**from project in-service date** to Year when cum. NPV turns 0)

(3) **Project Terminal Value / Commitment** - $K **20**
as a % of Cum. Net Present Value -0.1%

Background Information on REI Cost Calculation

REI investments have been identified in the following accomplishment plans.

Description	2010	2011	2012	2013	2014
Station Upgrades for Protection, Control and Load Rejection	21.1	36.8	97.1	91.9	73.4
Feeder Control Infrastructure	5.8	4.0	8.7	7.1	2.1
Wireless Telecommunication Stop-Gap	2.1	0	0	0	0
Wholesale Revenue Metering Changes	1.7	1.2	2.6	2.2	0.6
TOTAL	**30.8**	**42.1**	**108.5**	**101.1**	**76.2**

These costs were derived from a system wide analysis completed in November 2008.

The information used for this analysis included:

- CIA/CCRA applications by resource type
- Timeline and Percentage of commitment (from CIA/CCRA to actual generation connection)
- Forecast of MW of renewable generation connections

It was also assumed that a large percentage of Bio-Gas facilities would be connecting to Distribution Stations and that the remainder of Bio-Gas and all Wind and large solar would be connecting to sub-transmission feeders emanating from Transmission Stations. This analysis also assumed that generation would be concentrated to use up the connection capacity of the facilities. In other words, the number of TS's and DS's impacted was calculated as the MW amount of connecting generation divided by the average generation connection capacity of a TS or DS.

The connection of Distributed Generation to the distribution system requires the following modifications to distribution assets[1]:

1. In-line feeder reclosers require directioning so they can differentiate a downstream fault from an upstream fault. Downstream faults are being supplied through the reclosure and for these the reclosure should operate to clear the fault. The recloser should not operate for upstream faults because doing so can create unnecessary outages to Hydro One's load customers. Historically, there was no

[1] Modifications are also required to transmission assets to accommodate generation connecting to the distribution system.

need to direction reclosers as the energy to feed faults always came from one direction.

2. In-line feeder reclosers may require signaling to send transfer trip to downstream generation in order to prevent islanding.
3. Voltage Regulators require modification to allow then to control bi-directionally and to integrate into a coordinated feeder voltage control system.
4. Distribution Stations require upgrading to provide directioning of the reclosers, bus protection, the ability to perform load rejection functions that can no longer be done at Transmission Stations and remote monitoring and control.
5. Some TS's will require modifications to wholesale revenue metering to address issues due to station loading dropping below Measurement Canada Instrument Transformer accuracy range, to correct loss factors, and to modify the meter map with other LDC's.

The analysis estimated the number of Feeder in-line Reclosers, Voltage Regulators, TS's requiring Wholesale Metering Changes, and DS's connecting DG and/or needing Load Rejection ("LR") that would be impacted due to projected DG connections:

The cost of the program was based on the following unit costs:

Cost to add SCADA protections and LR capability to a DS: $610K
Cost to add signaling to an in-line recloser: $80K
Cost to add bi-directional and remote control to a voltage regulator: $53K

These costs are just for the protection and control (P&C) components and assume the DS, recloser, and voltage regulator are of a type that have interfaces to P&C technology. These unit costs also assume a large volume program that can leverage effective use of design and production standards and efficient mobilization for deployment.

The cost for Wholesale Revenue Metering Changes was based on an average cost allowance of $200K per TS impacted. It is expected that some TS's will require less and some more.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #22 List 1

Interrogatory

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 20-23 (Updated)

a) The costs associated with Investment Summaries D28-D33 total more than the Gross Capital Costs set out in the table on page 23. For each of the investment summaries, please identify precisely what activities and costs (gross and net) are incorporated in the proposed Green Energy Plan under the category "Renewable Enabling Improvements to the Distribution System" and reconcile the External Funding reported on page 23 with the total Recoverable Costs associated with Renewable Enabling Improvements associate with these ISDs. Also, please indicate the portion spending in each ISD that is associated with the three different activity areas discussed in the three paragraphs on pages 22-23.

b) Can the proposed spending for "Renewable Enabling Improvements to the Distribution System" be attributed to the specific areas/regions of Hydro One Networks' service area that are deemed to have the highest potential for renewable energy generation development? If not, please provide a copy of the system wide assessment/analysis undertaken to identify the required Renewable Enabling Improvements.

c) If the response to part (b) is yes, please provide a schedule that by region/area (consistent with the response to Question #20, part (b)) sets out for each region/area i) the gross capital investment, ii) the associated investment activities, iii) the costs of activities proposed to be partially funded by ratepayers (per pages 22-23) and iv) whether the region/area Is considered heavily loaded (per page 22, lines 16-19).

d) If the response to part (b) is yes, for each of the three regions/areas with the highest capital spending requirements for Renewable Enabling Improvements, please provide copies of the assessments/analysis undertaken to identify the spending required to support renewable energy generation.

e) With respect to Investment Summaries D30-D33 in Exhibit D1/Tab 3/Schedule 3, please confirm that the Recoverable costs include the anticipated recoveries from the Global Adjustment mechanism and those recoverable from Generators?

f) Please reconcile the Recoveries reported in ISD #28-33 with the Externally Funded value reported on page 23.

g) In either case, why are there no "recoverable costs" reported?

Response

a) Please refer to Exhibit H, Tab 7, Schedule 87.

b) Hydro One considers that all regions of the Hydro One service territory have some potential for renewable energy generation development. The assessment/analysis was done on a system wide basis. A summary of that analysis is in Attachment 1.

c) Not applicable – see response to b)

d) Not applicable – see response to b)

e) The recoverable costs include recoveries from the Global Adjustment mechanism. The scopes of these projects exclude any work that would fall into the definition of generator connection costs (e.g. generator end equipment for transfer trip is not included).

f) Please refer to Exhibit H, Tab 7, Schedule 87.

g) The "recoverable costs" are the costs shown as "Generator Funded Costs" in Exhibit H, Tab 7, Schedule 87.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #23 List 1

Interrogatory

Issue: #9.3

Reference: Exhibit A/Tab 14/Schedule 2, pages 21-23 (Updated)

a) Please provide the documentation from Hydro One Networks' current or previous Business Plans that demonstrates it was "considering adding DS monitoring at some of its heavily loaded distribution stations" (per page 22, lines 13-15).

b) Please provide documentation supporting the 30% factor referenced on page 22, line 17.

c) Does Hydro One Networks' proposed capital spending for 2010 and 2011 (per Exhibit D1 and D2) include any spending on DS monitoring for stations other than those included in the proposed Green Energy Plan? If yes, please indicate where this is documented in the Application.

d) Please explain more fully how the 5% factor referred to on page 23 (lines 2-3) was established.

e) Does Hydro One Networks' proposed capital spending for 2010 and 2011 (per Exhibit D1 and D2) include any similar work on Remote Protection and Control of Sub-Transmission Reclosers other than that included in the proposed Green Energy Plan? If yes, please indicate where this is documented in the Application.

Response

a) The plans to add monitoring at heavily loaded stations are described in previous rate filings. Most recently, this was discussed in the 2008 Distribution Rate Application (EB-2007-0681) in Exhibit D1, Tab 3, Schedule 3, page 10, lines 2 to 7.

b) The 30% factor is based on the assessment of senior staff on the percentage of Distribution Stations for which monitoring would be desirable for asset management and power quality objectives.

c) No. With the advent of the Green Energy Plan, Distribution Station monitoring plans have been superseded with the plans identified for REI and Smart Grid.

d) The benefit of LDC customers of these REI investments is considered small and the 5% figure is based on two considerations:

a. The cost required to just provide remote control of reclosers as compared to the cost required to implement the form of signaling required to enable connection of generation
b. The effectiveness to improvement of SAIDI of the location where signaling is needed for generation purposes as compared to the location that would be selected just for targeted SAIDI improvement

With respect to the first consideration, the form of signaling to enable generation requires much more demanding specifications than is required for remote control. To enable generation, the signaling must operate very quickly to achieve the fast action (measure in milliseconds) required for protection functions such as transfer trip. To provide just remote control, much slower signaling is acceptable and there is little risk to equipment damage or safety if the signaling fails. Consequently, the cost of telecommunications solutions for just remote control are about 10% of that required for generation enablement.

With respect to the second factor, the location where signaling from reclosers is implemented for generation are not often the most ideal locations for achieving benefit to load customers. Hydro One would select locations where large numbers of customer would be affected and where the opportunity exists due to electrical topology to “re-route” the supply from another station. This factor is difficult to assess with precision until the location of renewable generation is better known through the FIT process, however, based on the locations seen through the RESOP program, it is estimated that the relative effectiveness of generation-driven reclosers in improving SAIDI would not be more than 50%.

The 5% factor was derived as the 10% cost factor multiplied by 50%.

e) No.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #24a List 1

Interrogatory

Issue: #9.1

Reference: Exhibit A/Tab 14/Schedule 2, pages 25-30 (Updated)

a) With respect to page 26 (lines 3-6), please explain how "automated home energy networks" and "energy storage" qualify as smart grid investments.

b) With respect to page 25 (lines 4-6), please explain why field testing Plug-In Electric Vehicles is considered to qualify as a smart grid investment.

c) Please provide a comprehensive schedule that sets out the technologies and applications that Hydro One Networks proposes to "test" in the Owen Sound demonstration area (page 26). Please also describe how Hydro One Networks chose these technologies/applications.

d) Please describe how Hydro One Networks has ensured that the pilots and field testing it is proposing with respect to smart grid technologies are not duplicative of work that is being done elsewhere.

e) Does Hydro One Networks' proposed Smart Grid spending include any R&D activities? If so, please describe and indicate the funding involved.

f) Are any of the Smart Grid technologies/applications that Hydro One Networks has included in its plan related solely to the connection and integration of distributed generation? If yes, please describe.

Response

a) Automated home energy networks refer to a situation where the customer has set up a network in their home to help manage energy consumption. Typically, there is a logic controller (usually a computer) that communicates to appliances and devices and causes them to adjust usage in accordance with pre-programmed criteria. This could be smart grid related if the logic controller can accept signals from the meter and help manage in-home devices to meet system needs (e.g. reduce energy consumption at peak times). Energy storage refers to all types of energy storage (battery, compressed air, fuel cell), both large and small scale, that could be accessed and utilized by Hydro One under certain conditions. One example is to maintain power quality due to fluctuating distributed generation supply or other system conditions. In both these cases, Smart Grid technology is needed to assess conditions and communicate to devices in order to meet customer needs.

b) PHEVs (and EVs) are a potentially disruptive technology. Impacts can range from changes to distribution transformer planning, to the need for much more dynamic customer billing, or with time the potential for use as a form of dispatchable electric storage. The later functionality has been alluded to as a smart grid type application.

c) The specific technologies and applications that will be tested in the Smart Zone will depend upon the response to the planned Request for Proposal (RFP) that is expected to be issued in the fall of 2009. Please refer to Exhibit H, Tab 12, Schedule 46 for details of the RFP. The RFP will reach out to potential vendors who will propose technology to trial in the pilot area – this exercise will be used to develop the required business cases as a step before broader deployment.

Some potential technologies and back office applications are listed below that would be considered as essential to meet the scenario requirements.

Item	Description
DMS	Distribution Management System for monitoring and operational control of the distribution system
SCADA	System Control and Data Acquisition
DG Protection	Distributed Generation Protection – includes dynamic protection capability for changing system parameters
Distribution Automation	Automation of distribution devices
IED	Intelligent Electronic Devices
Volt/Var Controls	Monitoring and real time adjustment of voltage and var flows
Regulator and tap changer controls	Monitoring and real time adjustment of tap changer controls
Adaptive protection	Intelligent protective devices that adjust protection parameters to adapt to changing conditions e.g. loss of DG
GIS	Geospatial Information System comprising the location and connectivity of distribution assets
AMI	Advanced Metering Infrastructure represents the network of meters, collectors, repeaters and backhaul capability needed to capture hour meter reads and deliver them to the AMCC (Advanced Metering Control Computer)
Operational Data Store	Data warehouse of operational data used for analytics and state estimation
Enterprise Asset Mgmt	System used for planning and modeling asset maintenance and development.
ORMS	Outage Response Management System
ORMS Mobile with CAD integration	Mobile version of ORMS integrated with Computer-Aided Dispatch

d) Hydro One will continue to participate in extensive information sharing as per Exhibit A, Tab 14, Schedule 2, page 27. It should be recognized however that the GEGEA places Ontario ahead of many jurisdictions – we are well ahead when it comes to the deployment of smart meters and we are also going to be near the front when it comes to distributed generation, conservation and demand management and possibly PHEVs. In addition, Hydro One is a predominantly rural distributor and has a number of back office tools (IT applications) that in combination are certainly unique in the province and in totality possibly unique beyond. Nevertheless as noted we will continue to search for additional ways of collaboration above what's already mentioned in the evidence.

e) Yes, proposed Smart Grid spending includes R&D activities. We anticipate spending $5 M in 2010 and 2011. The specific studies will depend upon the response to the planned Request for Proposal (RFP) that is expected to be issued in the fall of 2009 (reference Exhibit H-12-46) as well as consultations with other industry stakeholders. In several areas, the R&D activities may be funded and jointly undertaken with Ontario Center of Excellence, Universities in Ontario and also with manufacturers. The R&D projects are expected to include utilization of renewable generation and storage technologies to reduce dependence on diesel in isolated areas of the distribution grid. Other projects being considered are DVAR, smoothing of power output from storage energy sources, plug in hybrid and charging systems etc.

f) No, the largest component of Smart Grid funding is to provide for the RFP and pilot implementation of the business scenarios described in Exhibit H, Tab 12, Schedule 46. Although there will be a need for technology to support the connection and integration of distributed generation it is expected that these systems, processes, monitoring and control devices will also be used to enhance the safety, reliability and overall efficiency of the distribution system

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #24b List 1

Interrogatory

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 25-30 (Updated)

a) With reference to page 29 (lines 14-21), please provide a schedule that clearly sets out the activities and costs associated with each of the referenced ISDs that are incorporated in the Smart Grid component of the proposed Green Energy Plan.

Response

a) The costs associated with each of the referenced ISD's that are incorporated in the Smart Grid component of the proposed Green Energy Plan are listed in the table below, and a description of the activities is included with the ISD documents provided in Exhibit D2, Tab 2, Schedule 3.

Table Listing Smart Grid Related components

ISD # and Title	2010 ($M)	2011 ($M)
O1 – Distribution Management System	0.6	1.3
O2 – Real Time Feeder Analysis	0.3	1.2
O3 – Incorporate Smart Meter Data in ORMS	1.7	2.1
O4 – ORMS Mobile IT Integration	1.0	1.0
O5 – Geospatial Integration (Distribution Operating)	0.6	0.6
O6 – Network Operations Buildings Sustainment	2.4	2.3
O8 – ORMS Upgrade	0.2	1.5
IT5 – GIS Implementation	2.6	2.7

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #25 List 1

Interrogatory

Reference: Exhibit A/Tab 14/Schedule 2, page 2

a) Please provide a schedule that sets out the impact on the proposed 2010 and 2011 revenue requirement of Hydro One Networks planned expenditures on Renewable Energy Generation Connection and Smart Grid, as set out in its Green Energy Plan.

b) Please provide a schedule that set out the calculation of the $8.0 M for 2010 and $30.7 M for 2011 referred to at lines 24-25.

Response

a) Please refer to Exhibit H, Tab 6, Schedule 11, part 2.

b) Please refer to Exhibit H, Tab 1, Schedule 151.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #26 List 1

Interrogatory

Issue: #9.1

Reference: Exhibit A/Tab 14/Schedule 2, page 31 (Updated)

a) How many core CDM programs does the OPA have for 2009 and why is Hydro One Networks only participating in four of them?

Response

There are four CDM core programs funded by the LDC Fund administered by the OPA that are being delivered through distributors and Hydro One is participating in all of them as detailed in the response at Exhibit H, Tab 4, Schedule 4.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #27 List 1

Interrogatory

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, page 31

a) What is the annual cost of the rate-funded PowerSaver® Plus program and where is it included in the proposed revenue requirement for 2010 and 2011?

Response

The PowerSaver® Plus program is forecast to cost $100,000 annually for 2010 and 2011. It is included in the $1 million rate-funding requirement for maintenance of minimum capability of MARR funded CDM programs and research.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #28 List 1

Interrogatory

Issue: #9.4 and #9.5

Reference: Exhibit A/Tab 14/Schedule 2, page 34

a) In Hydro One Networks' view, what are the implications of the OEB approving its proposed Green Energy Plan for the period 2010-2014? In particular, please outline what Hydro One Networks considers to be the implications of such approval for the post 2011 period?

Response

Please refer to Exhibit H, Tab 9, Schedule 52.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #29 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 4

a) Lines 6-7 state that the "2010 figures represents a decrease of 4.3% over the 2008 demand forecast". Please confirm whether the comparison is to 2008 forecast or actual values and, if forecast, which forecast (e.g., Was it the 2008 forecast as filed in EB-2007-0651?).

Response

The comparison pertains to 2008 actual values corrected on a weather-normal basis.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #30 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 8-9

a) Please confirm that the 2006-2008 values listed in Table 2 are not actual CDM impacts, but rather calculated based on a share of provincial CDM targets as set out in the IPSP. If they are "actual results", please provide details as to how they were determined.

b) Please provide the numerical basis for the referenced 15% (lines 5-6) and confirm whether it is only with respect to Hydro One Networks' retail customers or does it reflect Hydro One Networks' total customer base including Embedded Directs and LDC customers.

c) Re part (b), if just with respect to Hydro One Networks' retail customers, what portion of the total provincial use is accounted for by Hydro One Networks' Embedded Direct and LDC customers?

d) The IPSP (EB-2007-0707, Exhibit D/Tab 4/Schedule 1/Attachment 4, page 3) reports proposed conservation resource energy savings of 2.0 TWh in 2009, 6.9 TWh in 2011 and 8.8 TWh in 2011 (weather normal at the point of generation). Please reconcile these values and those included in Hydro One Networks' Application (Table 2) with the 15% share assumption and the need to account for losses (between point of generation and point of delivery).

Response

a) The CDM values in Table 2 in Exhibit A, Tab 14, Schedule 4 are CDM forecast based on Hydro One Distribution's share of the provincial target. Details of Hydro One Distribution's CDM forecast are provided in Appendix A, pages 8-10 of Attachment A report entitled "Net Load Impact of Conservation and Demand Management" in Exhibit H, Tab 12, Schedule 2.

b) The approximate 15% share pertains only to Hydro One Retail customers and does not include the share for embedded direct and LDC customers. The approximate 15% share is derived using the ratio of Hydro One Retail weather corrected load in 2004 (22,937 GWh at the wholesale purchase level) to Ontario total system weather corrected load (154,375 GWh at the generation level).

c) The share for Hydro One Embedded customers is approximately 12%.

d) The derivation of Hydro One Distribution's CDM forecast is provided in the following table. With the ratio as explained in (a) takes into consideration for losses between point of generation and wholesale delivery).

Year	OPA's Cumulative CDM Values in GWh (2)	OPA's Annual CDM Values in GWh	Hydro One Retail's Annual CDM Target in GWh	Hydro One Retail's Cumulative CDM Target in GWh
2007				311 (1)
2008	814 (2)	814	121	432
2009	1,960	1,146	169	601
2010	6,868	4,908	724	1325
2011	8,753	1,885	279	1604

Notes:
(1) 311 GWh was based on the first 1,350 MW CDM target approved by the OEB in EB-2007-0681
(2) 2008-2011 values were provided by the OPA consistent with the IPSP

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #31 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 10

a) Does Hydro One Networks use any models to forecast customer count? If so, please describe.

b) Hydro One Networks' customer count forecast appears to be developed entirely independently of the total load forecast (e.g., none of econometric models used to forecast total load include customer count as an explanatory variable). How does Hydro One Networks ensure consistency between its customer count forecast and its total load forecast?

Response

a) The increase in the customer count forecast is derived from the provincial housing starts forecast using the historical relationship between the two series.

b) Consistency between the customer count forecast and total load forecast is ensured in the load forecasting process. Hydro One's econometric models, forecasts of provincial number of building permits and number of households as well as retail customer counts are all based on the forecast of provincial housing starts. The building permit is a major explanatory variable used in monthly econometric model for Hydro One retail load, providing a link between retail load and customer count.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #32 List 1

Interrogatory

Reference: Exhibit A/Tab 14/Schedule 4, pages 21-22

a) Please explain how the State-Space approach in the regression equation differs from the standard Ordinary Least Square approach to regression analysis. Is this a common approach used in load forecasting?

b) Please confirm that the Distribution Load is sales to Hydro One Networks retail customers and clarify the definition of retail (i.e. is it total load excluding embedded directs and LDCs?). If not, please clarify the definition.

c) Over what period is the Monthly Econometric Model estimated?

d) How does the model account for the LDC acquisitions that Hydro One Networks made a number of years ago?

e) If the estimation period includes data for 2006, 2007 and/or 2008, has Hydro One Networks made any adjustments to account for the effect of conservation on load starting in 2006?

f) If no adjustment is made, doesn't this mean there is some double counting of conservation impacts: i) once in the Model itself and ii) again, when the explicit CDM adjustment is made per page 8? Please explain your response.

g) Please provide the values for the explanatory variable used to estimate the model and those used to forecast 2010 and 2011.

h) Please provide the forecast of sales for 2010 and 2011 based on Monthly Econometric Model.

i) The equation set out on page 21 (lines 10-16) does not include any seasonal or weather-related variables. However, the details provided on the output parameters make reference (line 22) to "seasonal factors". Please reconcile. Please also explain if and/or how the model takes into account the influence of weather on monthly loads.

j) If the estimation period for the model includes data for 2006 and/or later and no adjustments are made to the actual sales data prior to the estimation of the model to account for the impact of CDM please undertake the following:

- Re-estimate the model's "equation" – but for 2006 and beyond increase the distribution load by the estimated effect of CDM as set out at Exhibit A/Tab 14/Schedule 4, page 8.
- Provide the results in a form similar to that found on page 21, lines 20-34.
- Using this equation and the forecast values of the explanatory variables (page 23, lines 12-23) forecast the distribution load for 2010 and 2011.
- Prepare a schedule contrasting the results with those from part (h).

Response

a) The basic difference between the two types of regressions is as follow. Ordinary Least Squares assumes a unique historical relationship (i.e., fixed parameters over the full sample period) linking explanatory variables of the model and dependent variable. In contrast, State-Space provides a forecast by putting more emphasis on latest developments in the relationship between the explanatory variables of the model and dependent variable (i.e., estimated coefficients used for forecasting reflects most recent data) provided that such developments are considered by the algorithm to be systematic rather than transitory. State-Space (sometimes known as Kalman Filter) is a widely used econometric forecasting technique and is available in standard statistical packages (e.g., EVIEWS, SAS etc.)

b) Distribution load refers to energy supplied to Hydro One Retail customers and does not include load delivered through Hydro One Distribution system to Embedded Direct and LDC customers.

c) The Monthly Econometric Model includes data for the period January 1979 to March 2009.

d) The model accounts for the LDC acquisition by adding monthly historical load of all acquired LDCs dating back to January 1979 so that a consistent series is used as the dependent variable of the model.

e) The load impact of CDM was added to the historical load since the starting date of CDM initiatives in 2005, as explained in lines 4-5, page 14 in Exhibit A, Tab 14, Schedule 4.

f) See part e). There is no double counting.

g) Values for the explanatory variable used to estimate the model and those used to forecast 2010 are presented in the following tables. The model was not used to produce a forecast for 2011 because it is used as a short-term model to produce a forecast for up to 2 years.

Ontario GDP Used in Estimating Monthly Econometric Model and Associated Forecast
(in millions of chained 2002 dollars)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1971	164101	168817	166980	165915	172487	178288	178049	177986	172547	179057	177557	181659
1972	179347	178246	182841	179782	182704	188978	186743	185102	181832	186141	188917	191653
1973	188315	193029	195169	188806	191592	197849	194376	194046	188096	193666	196246	197772
1974	197297	199954	201205	192801	199057	203028	201249	201982	197058	199243	198728	199927
1975	200108	201345	195251	198990	198831	201882	202100	199738	199670	199961	202280	206572
1976	208217	209526	212498	214317	214896	214547	215711	217594	216958	213038	217845	216144
1977	217451	219690	220407	219577	221418	221856	224600	221708	221216	225278	227647	227528
1978	226348	229463	228060	227955	230655	233568	230844	231531	233981	232352	236068	236393
1979	237821	242766	241225	236710	236097	240882	241710	243079	238639	240522	237706	237601
1980	241489	234604	238956	235854	237588	238371	236175	234764	236412	240509	243190	241477
1981	244214	246665	250091	250215	252505	249809	257504	248790	252507	255427	256399	253216
1982	247017	252182	245977	244115	245400	242445	238804	243215	243222	244773	246454	242219
1983	244170	243479	246409	249887	251336	253958	259716	261556	263789	260527	265270	267463
1984	267538	265902	265808	272932	275072	275619	276200	281450	279242	284746	285229	281134
1985	284368	284016	286583	282178	286484	286356	284598	283714	293810	290215	294536	291942
1986	299785	297408	289955	301697	299741	293183	302742	299186	302544	301269	299687	302302
1987	302750	306555	304999	307626	309946	311498	318443	314727	319507	321877	326116	325156
1988	324633	324613	332424	332469	328945	325244	329333	330804	335137	335012	335479	337767
1989	341999	337363	336420	344114	343083	337765	340699	341617	348511	343580	345018	345467
1990	340884	344272	343103	341026	339766	335314	333877	335369	328238	335080	329044	328750
1991	320997	318757	315002	317662	324829	321667	324940	325320	329972	326912	328883	321155
1992	323315	328115	327801	327519	325542	324577	318515	323045	329299	328152	331121	324292
1993	323739	326336	327601	328753	327715	325800	325660	329974	337009	332120	335446	328528
1994	336385	339732	341048	346037	345603	343911	347977	350771	357906	357993	361231	353442
1995	353957	358164	360584	359336	358201	356107	356038	360609	368294	366163	369826	362194
1996	358435	362695	365146	365060	363907	361779	360710	365340	373126	367084	370756	363105
1997	369833	374228	376757	378378	377183	374978	379084	383951	392133	389541	393437	385318
1998	392391	397054	399737	398541	397283	394960	393994	399052	407556	405210	409263	400818
1999	412165	417063	419882	427365	426015	423525	427422	432909	442134	442752	447180	437952
2000	443200	448468	451498	455812	454373	451716	452498	458307	468073	459749	464348	454766
2001	456006	461426	464544	465895	464424	461708	455388	461234	471063	466328	470993	461273
2002	468090	473654	476854	476478	474973	472196	473051	479124	489334	483270	488104	478031
2003	481510	487233	490526	486834	485296	482459	473300	479376	489592	485457	490313	480195
2004	481541	487264	490557	495743	494177	491288	493335	499669	510317	503677	508715	498217
2005	500633	506583	510007	510172	508561	505588	503928	510397	521274	516934	522105	511331
2006	516141	522275	525805	525760	524100	521036	515380	521997	533120	528030	533312	522307
2007	527039	533303	536906	538900	537198	534057	529510	536307	547736	538526	543913	532689
2008	530201	536503	540128	538537	536836	533698	528046	534825	546222	528775	534064	523043
2009	518627	524791	528337	521625	519978	516938	511941	518513	529563	520243	525446	514603
2010	519851	526029	529584	532416	530735	527632	527113	533880	545257	540774	546183	534912

Ontario Building Permits Used in Estimating Monthly Econometric Model and Associated Forecast
(in 2002 dollar, index 2002=1)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1970	0.165	0.169	0.301	0.550	0.626	0.617	0.452	0.533	0.682	0.755	0.537	0.454
1971	0.236	0.424	0.539	0.794	0.842	0.958	0.789	0.651	0.651	0.665	0.543	0.380
1972	0.300	0.398	0.633	0.874	0.942	0.993	0.737	0.740	0.706	0.650	0.617	0.442
1973	0.364	0.444	0.730	0.720	1.046	0.931	0.788	1.063	0.710	0.866	0.950	0.662
1974	0.320	0.463	0.791	0.767	0.922	0.573	0.572	0.537	0.498	0.502	0.322	0.282
1975	0.206	0.368	0.493	0.730	0.825	0.769	0.797	0.804	0.721	0.752	0.561	0.442
1976	0.288	0.377	0.644	0.732	0.726	0.834	0.617	0.638	0.703	0.647	0.627	0.324
1977	0.208	0.276	0.694	0.788	0.900	0.842	0.697	0.640	0.617	0.481	0.545	0.380
1978	0.159	0.298	0.368	0.596	0.911	0.783	0.639	0.687	0.600	0.623	0.466	0.304
1979	0.124	0.212	0.411	0.505	0.719	0.618	0.538	0.692	0.500	0.525	0.437	0.349
1980	0.178	0.126	0.304	0.391	0.375	0.442	0.397	0.341	0.468	0.518	0.360	0.261
1981	0.183	0.219	0.491	0.721	0.802	0.619	0.588	0.405	0.318	0.284	0.418	0.554
1982	0.164	0.116	0.250	0.315	0.318	0.314	0.319	0.353	0.337	0.439	0.509	0.397
1983	0.241	0.312	0.553	0.828	0.542	0.503	0.548	0.444	0.509	0.482	0.416	0.304
1984	0.243	0.309	0.453	0.625	0.697	0.629	0.675	0.468	0.414	0.460	0.486	0.245
1985	0.219	0.317	0.586	0.818	0.872	0.805	0.829	0.746	0.844	0.798	0.634	0.436
1986	0.417	0.511	0.734	0.986	1.037	0.983	0.875	0.909	0.896	0.901	0.693	0.616
1987	0.594	0.695	1.327	1.263	1.278	1.227	1.054	1.013	1.049	0.852	0.724	0.604
1988	0.464	0.577	1.091	1.234	1.308	1.388	1.027	1.143	1.222	0.827	0.897	0.834
1989	0.611	0.798	1.142	1.441	1.276	1.174	1.097	1.045	0.946	0.894	0.846	0.675
1990	0.687	0.574	0.896	1.011	0.937	0.751	0.611	0.712	0.541	0.692	0.428	0.280
1991	0.195	0.261	0.410	0.718	0.846	0.811	0.890	0.710	0.693	0.799	0.908	0.286
1992	0.320	0.447	0.750	0.718	0.728	0.824	0.627	0.567	0.593	0.625	0.448	0.338
1993	0.270	0.275	0.483	0.596	0.603	0.690	0.582	0.591	0.619	0.513	0.484	0.317
1994	0.273	0.252	0.565	0.651	0.780	0.813	0.662	0.669	0.702	0.533	0.455	0.446
1995	0.282	0.226	0.447	0.506	0.557	0.551	0.454	0.484	0.470	0.517	0.402	0.310
1996	0.276	0.343	0.565	0.558	0.634	0.571	0.648	0.579	0.554	0.581	0.565	0.370
1997	0.458	0.386	0.597	0.855	0.816	0.756	0.892	0.724	0.797	0.733	0.635	0.439
1998	0.359	0.381	0.842	0.876	0.781	0.700	0.743	0.658	0.741	0.647	0.734	0.544
1999	0.398	0.445	0.850	0.899	0.974	0.949	0.975	0.853	0.837	0.824	0.935	0.621
2000	0.467	0.518	0.970	0.775	1.011	0.941	0.910	0.985	0.834	0.878	0.889	0.484
2001	0.570	0.670	0.982	0.760	1.118	1.052	0.918	0.882	0.829	0.858	0.991	0.591
2002	0.662	0.620	1.012	1.383	1.312	1.122	1.103	1.186	0.959	1.081	0.940	0.621
2003	0.705	0.572	0.988	1.055	1.199	1.301	1.170	0.977	1.135	1.012	1.070	0.679
2004	0.595	0.561	1.095	1.224	0.987	1.366	1.173	1.214	0.964	1.002	0.808	0.917
2005	0.575	0.654	0.978	0.978	1.140	1.191	0.966	0.902	0.891	0.871	0.815	1.292
2006	0.685	0.547	0.797	0.844	1.103	1.033	0.945	1.106	0.867	0.949	0.753	0.647
2007	0.732	0.445	0.800	0.826	1.037	1.112	1.009	0.927	1.112	1.085	0.897	0.801
2008	0.542	0.575	0.836	1.088	1.037	1.091	1.051	0.857	0.769	0.756	0.528	0.597
2009	0.368	0.330	0.578	0.607	0.752	0.765	0.669	0.673	0.658	0.666	0.565	0.628
2010	0.464	0.383	0.587	0.616	0.763	0.776	0.679	0.683	0.668	0.676	0.574	0.637

1
2

Dummy Variable D98Jan Used in Estimating Monthly Econometric Model and Associated Forecast
(in millions of chained 2002 dollars)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1971	0	0	0	0	0	0	0	0	0	0	0	0
1972	0	0	0	0	0	0	0	0	0	0	0	0
1973	0	0	0	0	0	0	0	0	0	0	0	0
1974	0	0	0	0	0	0	0	0	0	0	0	0
1975	0	0	0	0	0	0	0	0	0	0	0	0
1976	0	0	0	0	0	0	0	0	0	0	0	0
1977	0	0	0	0	0	0	0	0	0	0	0	0
1978	0	0	0	0	0	0	0	0	0	0	0	0
1979	0	0	0	0	0	0	0	0	0	0	0	0
1980	0	0	0	0	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0	0	0	0	0
1985	0	0	0	0	0	0	0	0	0	0	0	0
1986	0	0	0	0	0	0	0	0	0	0	0	0
1987	0	0	0	0	0	0	0	0	0	0	0	0
1988	0	0	0	0	0	0	0	0	0	0	0	0
1989	0	0	0	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0	0	0	0
1992	0	0	0	0	0	0	0	0	0	0	0	0
1993	0	0	0	0	0	0	0	0	0	0	0	0
1994	0	0	0	0	0	0	0	0	0	0	0	0
1995	0	0	0	0	0	0	0	0	0	0	0	0
1996	0	0	0	0	0	0	0	0	0	0	0	0
1997	0	0	0	0	0	0	0	0	0	0	0	0
1998	1	0	0	0	0	0	0	0	0	0	0	0
1999	0	0	0	0	0	0	0	0	0	0	0	0
2000	0	0	0	0	0	0	0	0	0	0	0	0
2001	0	0	0	0	0	0	0	0	0	0	0	0
2002	0	0	0	0	0	0	0	0	0	0	0	0
2003	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0

h) Please see Table 4b in page 3 in Exhibit H, Tab 3, Schedule 9. As explained in g), the model was not used to produce a forecast for 2011.

i) The load was corrected for abnormal weather effect during the historical period prior to using it in the model. Consequently, there was no need for explanatory variables related to weather conditions. Seasonal factor in the model output reflects seasonal patterns observed in weather corrected load. Retail load is not flat during the year after weather correction because of other factors. For example, number of hours requiring lighting is more during winter compared to summer.

j) See part e). There is no double counting of CDM in the model.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #33 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 23-24

a) Please confirm that the Distribution Load is sales to Hydro One Networks retail customers. If not, please clarify the definition.

b) Over what period is the Annual Econometric Model estimated?

c) How does the model account for the LDC acquisitions that Hydro One Networks made a number of years ago?

d) If the estimation period includes data for 2006, 2007 and/or 2008, has Hydro One Networks made any adjustments to account for the effect of conservation on load starting in 2006?

e) If no adjustment is made, doesn't this mean there is some double counting of conservation impacts: i) once in the Model itself and ii) again, when the explicit CDM adjustment is made per page 8?

f) Please provide the values for the explanatory variable used to estimate the model and those used to forecast 2010 and 2011.

g) Please provide the forecast of annual sales for 2010 and 2011 based on Annual Econometric Model.

h) If the estimation period for the model includes data for 2006 and/or later and no adjustments are made to the actual sales data prior to the estimation of the model to account for the impact of CDM please undertake the following:
   - Re-estimate the model's "equation" – but for 2006 and beyond increase the annual distribution load by the estimated effect of CDM as set out at Exhibit A/Tab 14/Schedule 4, page 8.
   - Provide the results of in a form similar to that found on page 23, lines 25-38.
   - Using this equation and the forecast values of the explanatory variables (page 23, lines 12-23) forecast the distribution load for 2010 and 2011.
   - Prepare a schedule contrasting the results with those from part (g).

Response

a) Distribution load pertains to the Hydro One Distribution retail customers.

b) The Annual Econometric Model is estimated over the period 1978 to 2008.

c) The model accounts for the LDC acquisitions by adding annual historical load of the acquired LDCs dating back to 1978 so that a consistent series is used as the dependent variable of the model.

d) The estimation period includes data since 1978. The load impact of CDM was added to historical load since the starting date of CDM initiatives in 2005, as explained in lines 4-5, page 14 in Exhibit A, Tab 14, Schedule 4.

e) See part d).

f) The values for the explanatory variable used to estimate the model and those used to forecast 2010 and 2011 are presented in the following table.

Year	YPDPHH	PELRES	PGASRES	CDD	HDD	TR	D98A
1978	61	52,462	21,219	232	4,391	18	0
1979	61	52,112	21,447	204	4,179	19	0
1980	60	53,198	22,077	244	4,309	20	0
1981	62	52,089	24,243	206	4,075	21	0
1982	62	51,747	25,719	141	4,114	22	0
1983	61	52,548	28,041	378	3,991	23	0
1984	63	53,623	27,035	240	4,049	24	0
1985	65	55,229	26,137	199	4,033	25	0
1986	64	54,840	24,780	197	3,920	26	0
1987	65	55,082	23,285	347	3,705	27	0
1988	67	55,202	22,027	389	4,026	28	0
1989	68	54,621	18,921	279	4,198	29	0
1990	66	55,577	18,350	281	3,593	29	0
1991	64	61,833	19,320	394	3,658	29	0
1992	64	68,331	19,387	105	4,046	29	0
1993	62	77,908	19,754	268	4,097	29	0
1994	62	76,351	21,091	252	4,083	29	0
1995	62	78,995	20,022	351	3,993	29	0
1996	61	75,881	19,654	235	4,130	29	0
1997	61	76,087	20,824	249	3,956	29	0
1998	63	76,087	22,495	398	3,197	29	0
1999	64	75,749	25,437	449	3,489	29	1
2000	66	73,627	33,912	244	3,787	29	1
2001	66	75,775	34,160	390	3,387	29	1
2002	66	70,948	28,239	521	3,590	29	1
2003	65	69,116	33,935	321	3,932	29	1
2004	66	71,262	36,747	236	3,749	29	1
2005	66	73,858	37,696	538	3,725	29	1
2006	68	81,001	43,823	386	3,336	29	1
2007	69	87,138	38,271	443	3,645	29	1
2008	70	86,107	36,869	287	3,782	29	1
2009	70	83,924	32,969	303	3,876	29	1
2010	70	83,507	34,880	303	3,876	29	1
2011	71	84,553	36,299	303	3,876	29	1

Note. Prices are in constant dollar/equivalent GWh

g) Please see Table 4a in page 2 in response to Exhibit H, Tab 3, Schedule 9 for the 2010 and 2011 forecast from the Annual Econometric Model.

h) See part d). There is no double counting of CDM in the model.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #34 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 25-26

a) For purposes of forecasting 2010 and 2011 energy sales using the End Use Model, what assumptions did Hydro One Networks make regarding residential unit energy consumption for the years 2005 through 2011 for each major residential end use? If the unit energy is assume to change over this period, please explain the basis for such changes.

b) For purposes of forecasting 2010 and 2011 energy sales using the End Use Model, what assumptions did Hydro One Networks make regarding changes in commercial energy use by building type for the years 2005 through 2011? What was the basis for any assumed changes?

Response

a) The residential unit energy consumption (UEC) by major end use used in the end use analysis is summarized below:

	2005	2006	2007	2008	2009	2010	2011
Room AC	383	385	387	390	392	395	397
Central AC	1,058	1,081	1,101	1,120	1,139	1,156	1,173
Water Heating	5,071	5,089	5,105	5,121	5,136	5,150	5,162
Lighting	1,520	1,522	1,523	1,524	1,526	1,527	1,528
Appliance							
Refrigerator	612	595	580	565	552	539	527
Freezer	450	437	426	415	406	396	387
Dishwasher	95	94	94	93	92	92	91
Clothes Washer	58	57	56	55	54	54	53
Clothes Dryer	822	818	813	808	803	797	791
Range	767	766	766	765	764	764	763

Space Heating							
Electric Baseboard	9,105	9,173	9,242	9,320	9,389	9,456	9,513
Heat Pump	7,992	8,002	8,012	8,021	8,031	8,041	8,051

The base year's UEC values are estimated by using the conditional demand analysis (CDA) approach. CDA is a multivariate regression technique which combines customer billing data with weather information and residential appliance survey to produce UEC estimates. Projected UECs take into consideration fuel prices, equipment cost and usage. The UEC analysis uses efficiency level in 2004 as the reference baseline and assumes no efficiency improvement after 2004. Existing equipment and buildings are assumed to remain at constant efficiency until they retire. New and replacement equipment and buildings are assumed to have the efficiency level of the new equipment and building in the base year. Equipment saturations are allowed to vary over the analysis period.

b) The commercial energy use by building type is determined by 3 key factors: the floor space growth rates, the ratio between rural and provincial growth rates and the energy intensity. Similar to the residential end-use model, the commercial end-use model uses efficiency level in 2004 as the reference baseline and assumes no efficiency improvement after 2004.

The floor space growth rates by building type are presented below and are based on Global Insight forecast prepared in January 2009.

Floor space growth rate for 2005-2011

	2005	2006	2007	2008	2009	2010	2011
Accommodation	0.95%	0.94%	1.87%	2.75%	0.89%	0.88%	0.88%
College	0.84%	0.83%	0.83%	0.82%	0.55%	0.79%	1.56%
Health care	0.84%	1.67%	2.46%	2.40%	1.56%	0.77%	1.53%
Multi-residential	1.26%	1.14%	2.66%	0.76%	0.54%	1.11%	1.60%
Offices	0.24%	1.20%	1.42%	1.13%	0.92%	0.21%	1.08%
Public service	0.00%	1.23%	2.44%	1.19%	0.84%	1.14%	1.12%
Recreation	2.82%	1.37%	1.35%	2.67%	1.30%	1.28%	1.27%
Religious	0.00%	0.00%	0.00%	1.30%	0.02%	1.28%	1.27%
Retail	1.81%	1.77%	2.44%	2.72%	1.99%	2.57%	2.82%
School	1.57%	0.39%	1.15%	1.14%	0.38%	1.12%	1.11%
Warehouse	0.56%	0.00%	0.84%	0.28%	0.21%	0.34%	0.41%
Grocery	0.52%	1.20%	2.73%	3.00%	0.93%	1.03%	1.03%
Commercial Misc.	0.00%	-0.19%	0.37%	0.40%	0.04%	-0.11%	0.56%

The ratio between rural and provincial growth rates is presented below and is based on Centre for Spatial Economics analysis prepared in March 2009.

Building Type	2009-2011
Accommodation	0.31
College	0.84
Health care	0.86
Multi-residential	0.66
Office	0.72
Public service	0.68
Recreation	0.89
Religious	0.68
Retail	0.89
School	0.84
Warehouse	0.95
Grocery	0.89
Commercial Misc.	0.88

The energy intensity by building type is based on Hydro One's provincial end-use model prepared in 2009. The model takes into consideration floor space, fuel price, GDP and weather data.

Electricity intensity growth rate for 2005-2011

Building Type	2005	2006	2007	2008	2009	2010	2011
Accommodation	0.49%	0.53%	0.56%	0.60%	0.64%	0.67%	0.71%
College	0.46%	0.49%	0.53%	0.56%	0.59%	0.62%	0.65%
Health care	0.79%	0.82%	0.86%	0.89%	0.93%	0.96%	1.00%
Multi-residential	1.11%	1.11%	1.11%	1.10%	1.10%	1.10%	1.10%
Office	1.15%	1.17%	1.20%	1.22%	1.25%	1.27%	1.30%
Public service	0.56%	0.61%	0.66%	0.71%	0.75%	0.80%	0.85%
Recreation	0.73%	0.76%	0.80%	0.83%	0.86%	0.89%	0.92%
Religious	0.13%	0.16%	0.19%	0.22%	0.25%	0.28%	0.31%
Retail	0.78%	0.81%	0.84%	0.88%	0.91%	0.94%	0.98%
School	0.41%	0.44%	0.47%	0.50%	0.53%	0.56%	0.58%
Warehouse	0.20%	0.24%	0.29%	0.33%	0.38%	0.42%	0.47%
Grocery	0.74%	0.77%	0.80%	0.83%	0.86%	0.90%	0.93%
Misc	0.49%	0.52%	0.56%	0.59%	0.63%	0.66%	0.69%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #35 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 15

a) With respect to page 15 (lines 25-26), please provide the details of the econometric model used to forecast load for the embedded distribution utility customers, including:
   - Explanatory variables used
   - Estimated coefficients and associated statistics
   - Data period used to estimate model
   - The values of the explanatory variables used to estimate the model

b) Please provide the forecast of embedded distribution utility customer load for 2010 and 2011 based on this model and the projected values of the underlying explanatory variables.

c) Were these results modified/adjusted at all as are result customer survey (page 16, lines 10-11) for the purpose of preparing the ”before” CDM forecast set out on page 19? If so, please explain how and why.

d) If the estimation period includes data for 2006, 2007 and/or 2008, did Hydro One Networks make any adjustments when estimating the model to account for the effect of conservation on load starting in 2006?

e) If not, doesn’t this mean there is some double counting of conservation impacts: i) once in the Model itself and ii) again, when the explicit CDM adjustment is made per page 8?

f) If the estimation period for the model includes data for 2006 and/or later and no adjustments are made to the actual sales data prior to the estimation of the model to account for the impact of CDM please undertake the following:
   - Re-estimate the model’s “equation” – but for 2006 and beyond increase the annual distribution load by the estimated effect of CDM as set out at Exhibit A/Tab 14/Schedule 4, page 8.
   - Provide the results of in a form similar to that found on page 23, lines 25-38.
   - Using this equation and the forecast values of the explanatory variables (page 23, lines 12-23) forecast the distribution load for 2010 and 2011.
   - Prepare a schedule contrasting the results with those from part (b).

Response

a) Details of the econometric model used to forecast load for the embedded distribution utility customers are provide below:

- Explanatory variables used

LHHOLD = logarithm of number of households in Ontario,
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,
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.

- Estimated coefficients and associated statistics

The dependent variable (LEMBLDCS) is logarithm of Embedded LDC load, where

$$LEMBLDCS = C(1) + C(2)*LHHOLD + C(3)*(LPELRES(-1) - LPGASRES(-1)) + C(4)*LCDD+C(5)*LHDD + C(6)*LEMBLDCS(-1) - C(4)*C(6)*LCDD(-1) - C(5)*C(6)*LHDD(-1) + C(7)*TR$$

	Estimated Coefficient	Standard Error	t-ratio
C(1)	2.319468	0.591119	3.923859
C(2)	0.174796	0.116072	1.505929
C(3)	-0.019754	0.015110	-1.307336
C(4)	0.018668	0.008817	2.117400
C(5)	0.024566	0.055219	0.444890
C(6)	0.548861	0.157199	3.491497
C(7)	0.014337	0.004211	3.404303

R-squared = 0.991, Adjusted R-squared = 0.989, Durbin-Watson Statistic = 1.70

- Data period used for the model is 1979 to 2008.

- The values of the explanatory variables used to estimate the model are presented in the following table.

Year	HHOLD	PELRES	PGASRES	CDD	HDD	TR
1977	2,727	53,850	20,135	207	4,103	17
1978	2,786	52,462	21,219	232	4,391	18
1979	2,857	52,112	21,447	204	4,179	19
1980	2,916	53,198	22,077	244	4,309	20
1981	2,970	52,089	24,243	206	4,075	21
1982	3,016	51,747	25,719	141	4,114	22
1983	3,073	52,548	28,041	378	3,991	23
1984	3,135	53,623	27,035	240	4,049	24
1985	3,185	55,229	26,137	199	4,033	25
1986	3,259	54,840	24,780	197	3,920	26
1987	3,343	55,082	23,285	347	3,705	27
1988	3,432	55,202	22,027	389	4,026	28
1989	3,520	54,621	18,921	279	4,198	29
1990	3,600	55,577	18,350	281	3,593	29
1991	3,656	61,833	19,320	394	3,658	29
1992	3,724	68,331	19,387	105	4,046	29
1993	3,785	77,908	19,754	268	4,097	29
1994	3,848	76,351	21,091	252	4,083	29
1995	3,895	78,995	20,022	351	3,993	29
1996	3,944	75,881	19,654	235	4,130	29
1997	3,993	76,087	20,824	249	3,956	29
1998	4,059	76,087	22,495	398	3,197	29
1999	4,125	75,749	25,437	449	3,489	29
2000	4,204	73,627	33,912	244	3,787	29
2001	4,219	75,775	34,160	390	3,387	29
2002	4,309	70,948	28,239	521	3,590	29
2003	4,382	69,116	33,935	321	3,932	29
2004	4,453	71,262	36,747	236	3,749	29
2005	4,519	73,858	37,696	538	3,725	29
2006	4,583	81,001	43,823	386	3,336	29
2007	4,641	87,138	38,271	443	3,645	29
2008	4,700	86,107	36,869	287	3,782	29

Note. Prices are in constant dollar/equivalent GWh, and households in thousand.

b) The forecast of embedded distribution utility customer load for 2010 and 2011 based on this model adjusted for 2009 actual and the projected values of the underlying explanatory variables are presented in the following table.

Variable	**2010**	**2011**
Forecast (EMBLDCS)	14,726	14,815
HHOLD	4,798	4,847
PELRES	83,507	84,553
PGASRES	34,880	36,299
CDD	301	301
HDD	3887	3887
TR	29	29

Note. Prices are in constant dollar/equivalent GWh, and households in thousand.

c) The results were not modified because the forecast was already consistent with the limited responses that Hydro One Distribution received from the embedded distribution utility customers through the customer survey.

d) The estimation period includes data since 1978. The load impact of CDM was added to historical load since the starting date of CDM initiatives in 2005.

e) See part d).

f) See part d). There is no double counting of CDM in the model.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #36 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 15-16

a) Please provide details as to how the "industrial analysis" combined the input from all of the referenced information sources to forecast the load for embedded industrial customers.

b) How did Hydro One Networks ensure that the forecasts provided through the customer survey (page 16, line 2) did not already include some/all of the CDM savings that are removed through the CDM adjustment (per page 8)?

Response

a) The forecast for industrial load was developed using the following sources:

- Historical customer load profiles were used to examine the dynamics of load over time. This helps identify whether a change in customer load is transitory or a prolonged change in load in response to changes in the economy.

- Events related to each industry were monitored using internal sources and public information. The forecast of industrial customer load takes into consideration recent development including information and announcement regarding individual company expansion plans or planned shutdowns.

- A customer survey was undertaken by Hydro One Distribution requesting customers to provide a load forecast and specific plans/events that may significantly affect their load.

- Company information through Hydro One Distribution account executives were also utilized in developing the forecast. Similarly, forecasts from external sources such as industry associations, government agencies etc. were incorporated into the forecast.

- Production and industry forecasts provided by external sources such as Global Insight, Conference Board of Canada, University of Toronto, Centre for Spatial Economics, etc. were also taken into account.

The forecast for embedded directs, before deducting CDM impact, is presented below:

Load Forecast for Embedded Directs Before Deductng CDM Impact

Year	Forecast from Customer Survey Summer Peak (%)	Winter Peak (%)	Average (%)	Final Forecast of Growth Rates for Embedded Directs (%)
2009	-11.3	-18.9	-15.1	-4.9
2010	-6.5	1.2	-2.7	0.1
2011	1.1	1.1	1.1	0.9
Sum of Growth Rates 2009-2011	-16.7	-16.5	-16.6	-3.9

b) Customers were asked to identify any major plans (including CDM) that may affect their load.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #37 List 1

Interrogatory

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 19

a) Please provide the schedule that sets out the forecast 2009, 2010 and 2011 load (before and after CDM) by rate class as used in Exhibits G1 and G2; the forecast customer count by class and the resulting average use per customer by class for each year.

b) Please explain how the load forecasts for individual customer classes are developed from the total load forecast.

c) Please provide a schedule that sets out for the years 2006-2008 - the load by customer class (both actual and weather normalized), the number of customers in each year and the resulting average use per customer (both actual and weather normalized).

Response

a) The forecast for 2009, 2010 and 2011 load (before and after CDM) by rate class for Hydro One Distribution as used in Exhibits G1 and G2 are provided in Tables a1 and a2 below. The forecast of customer count by class and the resulting average use per customer by class for each year are provided in Tables a3 to a5. All figures are shown at the customer sales (end-use) level and are net of distribution losses.

Table a1. Forecast of Sales After Deducting CDM by Rate Class in GWh

Rate Class	2009	2010	2011
Dgen	4	4	4
GSd	3,168	3,122	3,102
GSe	2,229	2,196	2,179
Lighting	148	143	142
R1	4,564	4,397	4,373
R2	5,578	5,375	5,328
Seasonal	745	718	712
ST	18,437	17,938	17,825
UGd	608	600	596
UGe	369	364	361
UR	1,364	1,311	1,303
Grand Total	37,214	36,169	35,926
Grand Total Excluding Embedded	20,982	20,405	20,260

Table a2. Forecast of Sales Before Deducting CDM by Rate Class in GWh

Rate Class	2009	2010	2011
Dgen	4	4	4
GSd	3,252	3,310	3,329
GSe	2,289	2,328	2,339
Lighting	152	152	153
R1	4,685	4,662	4,694
R2	5,726	5,699	5,719
Seasonal	765	762	764
ST	18,951	19,070	19,192
UGd	624	636	640
UGe	379	385	388
UR	1,400	1,390	1,399
Grand Total	38,227	38,399	38,621
Grand Total Excluding Embedded	21,539	21,634	21,748

Table a3. Forecast of Number of Customers by Rate Class

Rate Class	2009	2010	2011
Dgen	87	88	89
GSd	7,309	7,361	7,416
GSe	98,616	98,776	98,944
Lighting	0	0	0
R1	408,026	412,455	417,094
R2	365,208	367,107	369,078
Seasonal	156,489	156,901	157,327
ST	605	607	608
UGd	1,127	1,130	1,133
UGe	10,551	10,577	10,602
UR	139,160	140,540	141,977
Grand Total	1,187,179	1,195,542	1,204,267
Grand Total Excluding Embedded	1,186,881	1,195,245	1,203,969

Table a4. Forecast of Sales per Customer After Deducting CDM by Rate Class in kWh

Rate Class	2009	2010	2011
Dgen	48,336	47,483	46,856
GSd	433,375	424,147	418,230
GSe	22,607	22,230	22,023
Lighting	n.a.	n.a.	n.a.
R1	11,185	10,661	10,484
R2	15,272	14,641	14,437
Seasonal	4,762	4,578	4,527
ST	30,455,579	29,557,391	29,298,692
UGd	539,710	530,888	525,936
UGe	34,957	34,370	34,052
UR	9,802	9,331	9,181
Grand Total	31,347	30,253	29,832
Grand Total Excluding Embedded	17,678	17,072	16,828

Table a5. Forecast of Sales per Customer Before Deducting CDM by Rate Class in kWh

Rate Class	2009	2010	2011
Dgen	49,620	50,344	50,295
GSd	444,883	449,696	448,931
GSe	23,207	23,569	23,640
Lighting	n.a.	n.a.	n.a.
R1	11,482	11,304	11,253
R2	15,678	15,523	15,497
Seasonal	4,888	4,854	4,859
ST	31,304,529	31,422,195	31,544,444
UGd	554,042	562,867	564,543
UGe	35,886	36,440	36,552
UR	10,063	9,893	9,855
Grand Total	32,200	32,118	32,070
Grand Total Excluding Embedded	18,148	18,100	18,063

b) For embedded LDC and direct customers, the load forecast was developed using econometric model, industrial analysis and customer survey as explained in Exhibit A, Tab 14, Schedule 4 and additional details were provided in response to Exhibit H, Tab 7, Schedules 36 and 37.

For Hydro One retail customers, the load forecast was first developed at the wholesale purchase level using econometric and end-use models as explained in Exhibit A, Tab 14, Schedule 4 and additional details were provided in Exhibit H, Tab 7, Schedules 32 to 35. Forecasts for individual customer rate classes were developed using the total Hydro One Retail load forecast taking into account customer end-use details regarding historical dynamics of load per customer and expected future economic trends related to different rate classes. For example, residential building permits and housing starts, from which the forecast of number of customers was developed, were taken into account when developing the residential load forecast. For other customer rate classes, Ontario GDP by industry segment was analyzed. Distribution losses were also taken into account by individual rate classes. The load forecast for different rate classes were developed using the old rate classes for which historical data were available. The forecast was then mapped to the new rate classes.

c) The historical load for the years 2006-2008 for the old customer rate classes (both actual and weather normalized) for Hydro One Retail is provided in Tables c1 and c2 below. The number of customers in each year and the resulting average use per customer (both actual and weather normalized) are presented in Tables c3 to c5. The tables are presented in terms of the old rate classes for which historical figures are available.

Table c1. Weather Corrected Actual Sales Old Rate Class in GWh

Rate Class	2006	2007	2008
Retail			
Urban Residential	819	822	829
Residential High Density	3,757	3,756	3,778
Residential Normal Density	3,923	3,889	3,895
Residential-Seasonal High Density	337	345	344
Residential-Seasonal Normal Density	381	404	403
Farm !-Phase	1,906	1,869	1,850
Farm 3-Phase	212	222	224
Urban General Service	670	612	575
General Service 1-Phase	1,295	1,232	1,144
General Service 3-Phase	2,831	2,973	3,011
Transmission	1,174	1,135	1,089
Lighting	116	123	122
Subtotal	17,419	17,381	17,265
Acquired			
MEU-Residential	1,491	1,484	1,499
MEU-General Service	2,164	2,120	2,091
MEU-Large User	328	318	302
MEU-Lighting	26	26	26
Subtotal	4,008	3,947	3,918
Grand Total	21,427	21,329	21,182

Table c2. Actual Sales Old Rate Class in GWh

Rate Class	2006	2007	2008
Retail			
Urban Residential	797	818	821
Residential High Density	3,659	3,741	3,739
Residential Normal Density	3,820	3,872	3,855
Residential-Seasonal High Density	328	343	340
Residential-Seasonal Normal Density	371	402	399
Farm !-Phase	1,869	1,865	1,834
Farm 3-Phase	208	221	222
Urban General Service	658	611	570
General Service 1-Phase	1,272	1,231	1,134
General Service 3-Phase	2,781	2,969	2,986
Transmission	1,174	1,135	1,089
Lighting	116	123	122
Subtotal	17,055	17,332	17,110
Acquired			
MEU-Residential	1,450	1,472	1,470
MEU-General Service	2,131	2,124	2,072
MEU-Large User	324	318	299
MEU-Lighting	26	26	26
Subtotal	3,931	3,939	3,867
Grand Total	20,985	21,271	20,977

Table c3. Actual Number of Customers by Old Rate Class

Rate Class	2006	2007	2008
Retail			
Urban Residential	83,056	84,514	86,149
Residential High Density	305,174	311,639	316,550
Residential Normal Density	273,312	276,255	278,202
Residential-Seasonal High Density	71,128	71,260	71,347
Residential-Seasonal Normal Density	83,461	84,109	84,622
Farm !-Phase	88,915	88,379	87,442
Farm 3-Phase	1,210	1,223	1,267
Urban General Service	6,362	6,169	6,165
General Service 1-Phase	63,485	63,491	62,400
General Service 3-Phase	15,033	15,439	16,758
Transmission	366	364	371
Lighting	0	0	0
Subtotal	991,503	1,002,843	1,011,274
Acquired			
MEU-Residential	143,138	144,434	146,424
MEU-General Service	22,129	21,916	22,103
MEU-Large User	7	7	7
MEU-Lighting	0	0	0
Subtotal	165,274	166,357	168,534
Grand Total	1,156,777	1,169,200	1,179,808

Table c4. Weather Corrected Actual Sales per Customer by Old Rate Class in kWh

Rate Class	2006	2007	2008
Retail			
Urban Residential	9,858	9,724	9,627
Residential High Density	12,310	12,054	11,936
Residential Normal Density	14,352	14,076	14,001
Residential-Seasonal High Density	4,736	4,835	4,822
Residential-Seasonal Normal Density	4,562	4,799	4,762
Farm !-Phase	21,434	21,150	21,158
Farm 3-Phase	175,388	181,429	176,825
Urban General Service	105,281	99,244	93,190
General Service 1-Phase	20,399	19,407	18,336
General Service 3-Phase	188,295	192,592	179,687
Transmission	3,206,565	3,117,050	2,934,102
Lighting	n.a.	n.a.	n.a.
Subtotal	17,568	17,332	17,072
Acquired			
MEU-Residential	10,415	10,271	10,241
MEU-General Service	97,785	96,745	94,588
MEU-Large User	46,860,071	45,394,384	43,082,461
MEU-Lighting	n.a.	n.a.	n.a.
Subtotal	24,252	23,729	23,245
Grand Total	18,523	18,242	17,954

Table c5. Actual Sales per Customer by Old Rate Class in kWh

Rate Class	2006	2007	2008
Retail			
Urban Residential	9,601	9,683	9,528
Residential High Density	11,989	12,004	11,812
Residential Normal Density	13,978	14,018	13,856
Residential-Seasonal High Density	4,612	4,814	4,772
Residential-Seasonal Normal Density	4,443	4,779	4,713
Farm !-Phase	21,023	21,102	20,973
Farm 3-Phase	172,027	181,021	175,278
Urban General Service	103,448	99,109	92,381
General Service 1-Phase	20,044	19,381	18,173
General Service 3-Phase	185,018	192,330	178,154
Transmission	3,206,565	3,117,050	2,934,102
Lighting	n.a.	n.a.	n.a.
Subtotal	17,201	17,282	16,919
Acquired			
MEU-Residential	10,130	10,189	10,042
MEU-General Service	96,314	96,901	93,741
MEU-Large User	46,268,415	45,467,323	42,686,491
MEU-Lighting	n.a.	n.a.	n.a.
Subtotal	23,784	23,681	22,945
Grand Total	18,141	18,193	17,780

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #38 List 1

Interrogatory

Issue: #4.6

Reference: i) Exhibit A/Tab 14/Schedule 5, pages 2-17
ii) Exhibit A/Tab 14/Schedule 6, pages 4-10
iii) EB-2008-0272, Undertaking J2.7
iv) EB-2008-0187, Undertaking J1.1

a) Reference (i) refers to the prioritization process resulting in a preliminary investment plan (page 2, lines 12-13) and Reference (ii) refers to the process establishing minimum levels of investment (page 5, lines 8-9).
- Please provide a schedule that sets out for 2010 and 2011, the preliminary capital spending proposed by management, the minimum level of capital spending established via the process and the final proposed level of capital spending proposed in the Application using a level of detail similar to that found in References (iii) and (iv).
- Please provide a schedule that sets out for 2010 and 2011, the preliminary OM&A spending proposed by management, the minimum level of OM&A spending established via the process and the final proposed level of OM&A spending proposed in the Application using a level of detail similar to that found in References (iii).

b) The discussion in References (i) and (ii) refers to investments without making an particular distinction between capital and OM&A spending. Does the "investment prioritization process" consider all capital and OM&A programs jointly as one group or does it prioritize OM&A and capital projects as separate groups?

c) If the investment prioritization process considers both capital and OM&A spending as one "group", please indicate (based on Hydro One Networks' investment prioritization process):

- What areas of the proposed capital and OM&A spending for 2010 and 2011 would be reduced if overall funding was reduced by 10%. Please explain, with reference to the risks and impacts, why these areas were selected.
- What areas of the proposed capital and OM&A spending for 2010 and 2011 would be increased if overall funding was increased by 10%. Please explain, with reference to the risks and impacts, why these areas were selected.

d) If the investment planning process considers capital and OM&A spending separately, please respond to part (c) but address capital and OM&A separately.

Response

a) Provided below is a listing of information filed in this application compared to the Minimum level. Hydro One notes that the Minimum level of investment is neither a sustainable or desirable level of investment over the medium term but may be unavoidable because of constraints in the short term.

Distribution Capital (part 1)

	2010			2011		
	Filed	Minimum Level	Variance	Filed	Minimum Level	Variance
Sustaining						
Stations						
Strategic Spare Transformers	3.6	3.6	0.0	4.1	4.1	0.0
Mobile Substation Investments	2.5	2.5	0.0	2.8	2.8	0.0
Station Projects & Demand	7.9	7.9	0.0	8.4	8.4	0.0
Total Stations	**14.0**	**14.0**	**0.0**	**15.3**	**15.3**	**0.0**
Lines						
Trouble Call & Storm Damage	59.3	59.3	0.0	59.2	59.2	0.0
Joint Use & Relocations	30.4	30.4	0.0	30.5	30.5	0.0
Wood Structure Replacement	46.4	27.8	18.6	59	43.5	15.5
Lines PCB Equipment Replacement	0.7	0.0	0.7	3.1	0.0	3.1
Line Projects	31.1	21.1	10.0	31.4	21.2	10.2
Total Lines	**168.0**	**138.6**	**29.3**	**183.2**	**154.4**	**28.8**
Meters						
Customer Retail Meters	3.8	3.8	0.0	4.1	4.1	0.0
Total Sustaining	**185.8**	**156.4**	**29.4**	**202.6**	**173.8**	**28.8**
Development						
Connections, Upgrades and Cancel	113.5	110.6	2.9	115.4	112.4	3.0
System Capability Reinforcement	47.0	40.0	7.0	50.9	46.8	4.1
Generation Connections	16.5	6.4	10.1	33.4	6.0	27.4
Wholesale Revenue Meters	7.9	7.9	0.0	2.8	2.8	0.0
Smart Grid	20.8	20.0	0.8	49.9	49.1	0.8
Total Development	**205.7**	**184.9**	**20.8**	**252.4**	**217.2**	**35.2**
Operations						
Operations Capital	8.1	6.2	1.9	11.2	8.7	2.5
Total Operations	**8.1**	**6.2**	**1.9**	**11.2**	**8.7**	**2.5**
			0.0			0.0
Total Sustaining, Development, Operations	**399.6**	**347.5**	**52.1**	**466.2**	**399.7**	**66.5**
Shared Services & Other Capital						
Information Technology	20.0	14.2	5.8	17.5	11.7	5.8
Cornerstone	7.6	7.6	0.0	3.2	3.2	0.0
Facilities & Real Estate	29.0	21.6	7.4	28.8	22.4	6.4
Transport, Work & Service Equip	108.2	96.5	11.7	61.3	57.8	3.5
Total Shared Services & Other Capital	**164.8**	**139.9**	**24.9**	**110.8**	**95.0**	**15.8**
Total Distribution Capital	**564.4**	**487.4**	**76.9**	**577.0**	**494.7**	**82.3**

Notes:
1. Conservation & Demand Management will be either funded by OPA and/or adjusted under global adjustment.
2. Smart Metering costs are covered in a Reg. Asset account as per OEB decision.

Distribution OM&A (part 2)

	2010			2011		
	Filed	Minimum Level	Variance	Filed	Minimum Level	Variance
Sustaining						
Stations						
Distributing & Regulating Station	24.4	18.7	5.7	26.8	20.7	6.1
Land Assessment and Remediation	5.7	2.1	3.7	4	2.1	1.9
Total Stations	**30.2**	**20.8**	**9.3**	**30.8**	**22.8**	**8.0**
Lines						
Trouble Call Response, Cable Locates and Disc.	87.0	87.0	0.0	90.8	90.8	0.0
Line Maintenance	31.2	24.0	7.2	29.9	21.9	8.0
PCB Equipment & Waste Management	9.4	4.4	5.1	15	4.5	10.5
Other Services	12.5	12.0	0.5	12.5	12.0	0.5
Total Lines	**140.2**	**127.4**	**12.8**	**148.2**	**129.2**	**19.0**
Meters, Telecom, & Control	14.9	8.2	6.7	16.8	9.9	6.9
Vegetation Management	133.2	111.7	21.6	144.6	114.9	29.7
Total Sustaining	**318.5**	**268.1**	**50.4**	**340.4**	**276.9**	**63.5**
Development						
Data Collection, Engineering and Tech. St.	6.8	3.6	3.2	6.9	3.7	3.2
Standards and Technology	4.9	4.0	0.9	5.0	4.1	0.9
Smart Grid Standards & Technology	10	10.0	0.1	10.0	10.0	0.1
Total Development	**21.7**	**17.6**	**4.1**	**21.9**	**17.8**	**4.1**
Operations						
Operations	12.4	12.4	0.0	12.8	12.8	0.0
Operating Support	4.3	4.3	0.0	4.8	4.8	0.0
Total Operations	**16.7**	**16.7**	**0.0**	**17.6**	**17.6**	**0.0**
Total Sustaining, Development & Operations	**356.9**	**302.4**	**54.5**	**379.9**	**312.3**	**67.6**
Customer Care	**106.3**	**104.8**	**1.5**	**102.4**	**101.8**	**0.6**
Prioritized Shared Services and Other OM&A Costs						
Information Technology	79.1	58.9	20.2	81.9	61.5	20.4
Cornerstone	-4.6	-4.6	0.0	-7.8	-7.8	0.0
Total Prioritized Shared Services and Other	**74.5**	**54.4**	**20.1**	**74.1**	**53.7**	**20.4**

Notes:
1. Conservation & Demand Management will be either funded by OPA and/or adjusted under global adjustment.
2. Smart Metering costs are covered in a Reg. Asset account as per OEB decision.

b) No, capital and OM&A programs are prioritized as separate groups since different constraints apply to each of them.

c) Not applicable.

d) The budget proposed for the test years is based on the investment planning and prioritization process described in Exhibit A, Tab 14, Schedules 5 and 6. Application of the planning and prioritization process results in a set of investments that effectively balance our asset needs with due consideration for resource availability

and the mitigation of risk to Hydro One's business values. Hydro One considers the proposed test year expenditures to be prudent and does not recommend a reduction in the budget.

If the test year budget were reduced, the risk to Hydro One's business values would increase. The converse is also true – an increase in budget would decrease the risk to business values. Hydro One would need to re-apply the prioritization process to identify which work programs could be cut to minimize the increase to the Company's risk. Similarly, the prioritization process would need to be run to identify which programs could be increased in order to maximize the reduction to the Company's risk.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #39 List 1

Interrogatory

Issue: #4.6

Reference: i) Exhibit A/Tab 14/Scheduele 5, pages 7-8 and pages 13-14
ii) Exhibit A/Tab 14/Schedule 6, pages 4-6

a) The discussion in Reference (i) indicates that after consideration of factors such as asset condition and reliability performance a replacement program for wood poles is developed and then this "final wood pole replacement plan is included in the Hydro One Investment Plan for prioritization" (page 8, lines 17-23). However, Reference (ii) suggests that wood pole programs with various levels of replacement are developed and they are all considered/evaluated in the corporate-wide Prioritization process. Please reconcile.

b) Similarly, with respect to the example given for System Capability Reinforcement (page 13, lines 10-17), the discussion indicates that after an assessment of alternatives and evaluation against other Development capital investments, the proposed spending was include in the Hydro One Investment Plan for prioritizing. This appears to be inconsistent with Reference (ii) which suggests that alternative spending levels are evaluated on corporate-wide investment basis. Please reconcile.

Response

a) The "plan" referred to in Reference (i) and that is inputted into the Investment Prioritization Process contains multiple investment levels for the Wood Structure Replacement Program. It is effectively made up of alternative expenditure levels along with associated risk profiles. The Investment Prioritization Process then takes these multiple investment levels and selects one as outlined on page 9 in Exhibit A, Tab 14, Schedule 6.

b) System Capability Reinforcement investments are prioritized on a corporate-wide basis using several levels of investment. The discussion on page 13, lines 10 to 16 involves the development of the individual projects that make up System Capability Reinforcement. Different levels of System Capability Reinforcement are made up a number of individual projects that are aggregated to form macro investments used for prioritization.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #40 List 1

Interrogatory

Issue: #4.2 and #4.6

Reference: Exhibit A/Tab 14/Schedule 6, pages 6-7

a) Please explain the basis for the $120 M liability value associated with not replacing the 20,000 poles.

b) What is the increased spending over the five year period associated with replacing the 20,000 poles?

c) Please reconcile the comments on page 7 (lines 6-9) that the minimum level of spending is manageable as poles usually require a degree of adverse weather to cause failure with the comment on the same page (lines 14-16) that the failure of 20,000 poles has a medium likelihood of occurrence.

Response

a) In this simplified example, a forced reduction in Hydro One's investment in the pole replacement program to Minimum would result in 20,000 fewer poles being replaced during the 5 year planning horizon. As a result, $120M less capital would be spent during this time period. If this Minimum level of spending and associated work accomplishment was held for a five year period Hydro One would be on the boundary of unacceptable risk just beyond this 5 year planning horizon. To address this risk, replacement work involving 20,000 poles at a cost of $120M (referred to as the "liability") would need to be undertaken and completed shortly after the end of this 5 year period. To maintain simplicity, no statement is made here respecting the actual feasibility or incremental costs of such an undertaking.

Further, a delay in the replacement of 20,000 end of life wood pole for 5 years would represent the harvesting of assets. The Distribution System Code provides flexibility relating to the replacement of defective assets; however, should these poles be left unattended for an extended period of time such as 5 years, they will be considered to be outside the bounds of the DSC requirements.

The harvesting of assets and thereby exposing the company to significant risks and a "liability" of this magnitude is neither sustainable nor a desirable mode of operation. The company's objectives and the resulting prioritization process are structured to deter harvesting of assets.

b) See response to a) above.

c) The specific wording in Exhibit A, Tab 14, Schedule 6 pages 6-7 is:

A replacement deficiency of this magnitude would increase the number of substandard poles in the system by this amount. It can be demonstrated, that over a 5-year period this is manageable, as poles usually require a degree of adverse weather to cause failure, even when substandard.

To clarify, the investment prioritization process considers risk over a 5 year planning period. By definition, an investment at the minimum level places the company at the boundary of unacceptable risk just beyond the 5 years planning horizon. In this example, a reduction of investment to minimum would result in a growing number of defective and substandard poles across the 5 year planning horizon and an associated growth in risk levels. Within the 5-year timeframe, risk would be increasing but would not likely increase to the boundary of the "red-zone" of unacceptable risk until just after the 5-year planning horizon. It is in this context that, for simplicity, we refer to the situation during the 5-year planning horizon as manageable. Just after the 5-year planning horizon, as noted in Exhibit A, Tab 14, Schedule 6 pages 7, the risks would include, among other risks, "*a severe financial risk with a medium likelihood of occurrence*" placing this particular risk on the boundary of the red zone. This same exhibit goes on to say that, "*The associated regulatory risks will increase and reliability will deteriorate.*"

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #41 List 1

Interrogatory

Issue: #4.6

Reference: Exhibit A/Tab 14/Schedule 8, page 2

a) Have there been any delays in the execution of Hydro One Distribution's planned 2008 or 2009 work programs as a result of material and equipment availability? If yes, please indicate specifically what program areas have been impacted, what the associated materials/equipment are and what the resulting delay was.

b) Please describe how Hydro One Networks is addressing the material and equipment availability issue.

Response

a) There have been no delays to date in the 2008 and 2009 Hydro One Distribution work programs that were the result of material or equipment availability.

b) Hydro One has the following strategies in place to mitigate future availability issues:
- Planning and releasing of multi-year work programs
- Standardization of designs and material requirements
- Strategic procurement initiatives with key vendors to ensure long-term equipment and fleet availability

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY # 42 List 1

Interrogatory

Issue #3.2

Ref: Exhibit A-15-2/p3

a) The report noted that Hydro One Networks performed better than average in terms of hours per tree, but less than average in terms of cost per tree (lines 13-17). The report suggests that this was due to Hydro One Networks' long cycle length. However, why wouldn't a longer cycle length and a greater vegetation per tree also lead to a higher hour per tree value as well?

b) Did the consultants consider at all the fact that the better than average performance when measured based on hours but lower than average performance based on costs was due to a higher per hour labour rate for Hydro One Networks relative to the comparators? If not, please discuss whether this would explain the observed differences.

Response

a) As noted on page 22 of Attachment 1 in Exhibit A, Tab 15, Schedule 2, CN Utility indicates that the cycle length does impact both labour hours per tree and cost per tree and "if the impacts of cycle length…were to be factored in, CNUC expects Hydro One's relative efficiency to be average for costs per tree and to be significantly better than average for labour hours per tree."

b) The differences in performance based on labour hours and costs can be attributed to various factors as discussed in the interrogatory response at Exhibit H, Tab 1, Schedule 159. Given the wide variety of factors that can influence costs, it is not appropriate to conclude that higher labour rates are the reason for the observed differences. CN Utility did not conduct a compensation study as the emphasis of the study was on efficiency measures as noted on the top of page 16, of Attachment 1 in Exhibit A, Tab 15, Schedule 2.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #43 List 1

Interrogatory

Issue: #3.2

Reference: Exhibit A/Tab 15/Schedule 2, Attachment 1

a) With respect to page 16, please clarify whether "kilometers managed" are the total line kilometers (i.e., the kilometers managed over the total vegetation cycle) or the kilometers subject to vegetation management in a given year of the cycle.

b) Please confirm that if the definition in part (a) is total line kilometers then utilities with longer cycles will have lower values. However, if the definition is kilometers "managed" in a given year then utilities with longer cycles could be expected to have higher values due to the cycle length problem outlined on page 18.

c) With respect to page 23, please clarify the definition of "kilometers" used in section 4.1.5.

d) With respect to page 27, please explain why the effect of the "cycle period" is minimized when using a system kilometer measure.

e) With respect to page 29, please confirm that longer cycle times will tend to:
- Increase annual vegetation management costs by virtue of the increased vegetation mass that will accumulate.
- Decrease annual vegetation management costs by virtue of the fact less kilometers are treated each year.

Response

a) "Kilometres Managed" on page 16 refers only to the kilometers treated over the time period and not the total number of line kilometers on the entire system.

b) When using measures such as "Labour Hours per Kilometre Managed" and "Cost per Kilometre Managed", utilities on a longer cycle will be expected to have higher values if all things are equal. This is due to the additional growth and biomass that results over the course of a longer cycle as discussed at the bottom of page 18 in Attachment 1 of Exhibit A, Tab 15, Schedule 2.

c) "Kilometres" used in page 23 is equivalent to "Kilometres Managed" and refers only to the kilometers treated over the time period as described above in part (a).

d) The "Total UVM per System Kilometre" measure depicted on page 27 uses the entire system kilometers as a basis. Measures that use this basis examine costs from a system wide perspective as opposed to more narrow measures that only examine performance on kilometers that have been treated. As discussed in part (b) above, measures based on kilometers treated are influenced to a great degree by the cycle length. The system wide measure on the other hand minimizes the cycle length influence by including all kilometers and not only the subset that was treated.

e) Hydro One confirms that the points noted above are correct. It should be noted however, that the two points are not equally impactive and the cost relationship between the two points is not linear

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #44 List 1

Interrogatory

Issue: #3.1 and #4.2

Reference: Exhibit A/Tab 16/Schedule 1, pages 3-4

a) Please provide the results of the most recent First Quartile and CEA benchmarking studies that Hydro One Networks has participated in dealing with its Distribution Business (page 4).

b) Please indicate those areas where Hydro One Networks has solicited information on best practices over the past two years and what changes have been adopted based on this information (page 3, lines 20-21).

Response

a) Please see interrogatory response at Exhibit H, Tab 1, Schedule 29.

b) Hydro One is continuously soliciting information in a variety of areas to learn about best practices and to improve operations. Three examples of particular focus areas in recent years are:

- **Work Management** – As noted in Exhibit D1, Tab 3, Schedule 7, Hydro One implemented SAP and its modern work management functionality in June 2008. Prior to implementing SAP, information was gathered about best practices and the solutions that were in use at other utilities.

- **Vegetation Management** – In recent years, a significant amount of information has been gathered to help improve efficiencies. Exhibit A, Tab 15, Schedule 2, Attachment 1 contains the most recent information collected in the form of a benchmarking survey. That study provides support for Hydro One Distribution's decision to reduce the program's cycle length and also contains information about various initiatives undertaken to improve the program.

- **GIS Implementation** – Information has been collected about industry best practices and effective approaches to implementing GIS technology. As discussed in ISD IT5 in Exhibit D2, Tab 3, Schedule 3, Hydro One Distribution is proceeding with the implementation of a Geographic Information System.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #45 List 1

Interrogatory

Issue: Issue #3.1 and #4.2

Reference: Exhibit A/Tab 16/Schedule 1, page 5

a) Please indicate what initiatives gave rise to the 2009 non-Cornerstone savings shown for OM&A and Capital.

Response

a) The initiatives that give rise to the 2009 non-Cornerstone savings are:

- Labour productivity resulting from the early stage implementation of the smart meter initiative as well as savings from the recently negotiated collective agreements;
- Information Technology enablement, example – efficiencies gained through the implementation of new business processes and tools in the field to enable improved planning, scheduling and reporting of work;
- Savings resulting from improvements in our strategic sourcing initiatives; and,
- Savings resulted from other areas and processes across the organization.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #46 List 1

Interrogatory

Issue: #1.1

Reference: i) Exhibit A/Tab 18/Schedule 1, pages 2-3
II) EB-2008-0272 Decision, page 21

a) Please provide a schedule identifying the planned 2009 capital spending included in the current Application for each of the projects included in the Directive from EB-2008-0187.

b) In Reference (ii) the Board made the following finding:

> *However, the Board finds that Hydro One's evidence as it relates to the factors driving the spending levels has been insufficient. In addition to the demographic data that was filed, Hydro One should have filed more real-life data samples related to the determinative factors referenced in the company's investment plan process. This need not have been a reproduction of all the company's documentation related to its internal decision-making but rather an illustrative cross-sectional sampling related to the determinative factors and pertaining to various asset groupings.*

Since Hydro One Networks uses the same investment planning prioritization process for transmission and distribution, please indicate how Hydro One Networks has refined the current application to address the concern expressed by the Board.

Response

a) The following table gives the year-end projection and budget, for the four projects detailed in EB-2008-0187 (in $M):

Description	**2009 Forecast**
New Connection & Upgrades	98.0
Smart Grids Pilot Projects	10.0
Leasehold Improvements Plan	0.0
Cornerstone Project (Phase 1 & 2)	94.5
Total	**202.5**

b) The "determinative factors" referred to by the Board in the EB-2008-0272 decision include asset condition, reliability requirements, customer requirements, safety requirements and environmental criteria. In the current application, (EB-2009-0096), there are multiple examples which fulfill the Board's request for information.

One example (pole replacement) serves as a "walk through" of the investment prioritization process (Work Program Prioritization, Exhibit A, Tab 14, Schedule 6). Other examples throughout the evidence contain data that would be inputs in the assessment of residual risk and decision-making regarding the prioritization of assets.

With reference to the Board's list of determinative factors above, such concrete "real life" examples include the following:

Asset Condition: An entire section of the evidence (Exhibit D1 Tab 2 Schedule 1) details the Asset Condition Assessment process and summarizes information relevant to the asset prioritization process. The data included covers a wide range of assets including wood poles, transformers, lines and rights-of-way.

Reliability and Health and Safety: On pages 20-22 of Exhibit D1 Tab 3 Schedule 2, evidence is provided regarding the impact of the pole replacement program on reliability and safety (i.e. the exhibit discusses the statistics surrounding the premature decay of red pine poles, and the potential negative effect on reliability, and the safety of the public and our employees.)

Environmental: In Exhibit D1 Tab 3 Schedule 2, page 23, data is presented regarding the PCB replacement program, (regulatory requirements and thresholds), which is relevant to the mitigation of environmental risks.

Other similar examples exist throughout the evidence of the various types of data that would be pertinent to decisions regarding asset investments, and the residual risk prioritization process.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #47 List 1

Interrogatory

Issue: #5.1

Reference: Exhibit B1/Tab 1/Schedule 1

a) Please confirm that, under Hydro One Networks' proposal, the Board-approved ROE and deemed short-term debt rate for its distribution business for 2010 and 2011 will likely differ from that applicable to the balance of the electricity distributors in the province who are regulated by the OEB.

b) What are Hydro One Networks' views regarding the establishment of a variance account to track the revenue requirement impact of such differences?

Response

a) Hydro One Networks proposal will likely differ from that applicable to the balance of electricity distributors in the province. Hydro One Networks proposal for the deemed short-term debt rate and ROE is to be based on the September 2009 and September 2010 Consensus forecast and Bank of Canada data rather than using January 2010 and January 2011 data. The reason Hydro One Networks is proposing to use the September forecasts, respectively is based on Hydro One rates becoming effective in January rather than May of 2010 and 2011 respectively.

b) Hydro One does not believe a variance account is required.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #48 List 1

Interrogatory

Issue: #1.2 and #5.2

Reference: Exhibit B1/Tab 2/Schedule 1, pages 6-7

a) If there is a more recent forecast available from Consensus Forecasts for 10-year government of Canada bond yields for 2009, 2010 and/or 2011, please update the Hydro One forecast yields set out in Table 4 using this forecast and the Hydro One credit spreads for the month the forecast was issued.

Response

Please refer to Exhibit H, Tab 3, Schedule 27.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #49 List 1

Interrogatory

Issue: #5.2

Reference: Exhibit B2/Tab 1/Scheule 2, page 4

a) The Updated Schedule shows two 10-year issues in 2009 – one in June and a second in September. Please confirm that the values shown are the actual values.

Response

The values shown are for planned debt issues - not actual debt issues.

Please refer to Exhibit H, Tab 3, Schedule 29.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #50 List 1

Interrogatory

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schedule 2, pages 4-10

a) With respect to Planned Station Maintenance (page 6), will the planned spending on PCB testing and retro-fills in 2010 and 2011 complete Hydro One Networks' obligations to retire PCBs in excess of 500 ppm?

b) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Station Sustaining OM&A that were considered during the prioritization process and identify the risks attributed to each.

Response

a) No. For added details refer to Exhibit H, Tab 3, Schedule 64, part (b).

b) For the purposes of the Investment Prioritization Process, Station Sustaining OM&A is divided into the following two categories:

1) Station Maintenance – Stations Demand and Corrective Maintenance and Planned Station Maintenance

2) Land Assessment and Remediation

For Category 1, the following table summarizes the funding levels considered.

Level	Total Cost Over 5 Yrs ($M)	Normalized Risk						
		Financial	Reputation	Regulatory	Reliability	Efficiency	Safety & Environment	Customer
Minimum	$99.9	Consequence: **Major** Likelihood: **Very Likely**	Consequence: **Major** Likelihood: **Very Likely**	Consequence: **Severe** Likelihood: **Medium**	Consequence: **Severe** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Likely**	Consequence: **Major** Likelihood: **Very Likely**	Consequence: **Major** Likelihood: **Very Likely**
Level 1	$119.3	Consequence: **Major** Likelihood: **Likely**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**
Level 2	$129.6	Consequence: **Major** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Major** Likelihood: **Unlikely**	Consequence: **Major** Likelihood: **Unlikely**

The higher levels represent an increase in the amount of planned and corrective maintenance activity.

For Category 2 (i.e. Land Assessment and Remediation), the following table summarizes the funding levels considered.

Level	Total Cost Over 5 Yrs ($M)	Normalized Risk						
		Financial	Reputation	Regulatory	Reliability	Efficiency	Safety & Environment	Customer
Minimum	$9.3	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Very Likely**	Consequence: **Major** Likelihood: **Likely**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Remote**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Likely**
Level 1	$12.1	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Major** Likelihood: **Likely**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Remote**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Medium**
Level 2	$12.1	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Remote**	Consequence: **Major** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Unlikely**
Level 3	$12.1	Consequence: **Minor** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Remote**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Minor** Likelihood: **Unlikely**

While the funding over the 5 year period is the same for levels 1 to 3, the higher levels represent the completion of remediation of priority sites at earlier dates. Once all priority sites are remediated, the program will be complete.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #51 List 1

Interrogatory

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schledule 2, pages 10-27

a) Please explain why the provision for storm-related OM&A expense was increased from the $6 M included in 2008 rates (EB-2007-0681, C1/2/2, page 10) to $8 M for 2010 and $8.3 M for 2011 (page 13).

b) The level of 2008 costs for Trouble Calls included in Hydro One Networks 2008 Rate Application was $58.9 M. The increased allowance for storm-related OM&A expenses explains some but not all of the higher $65.3 M and $68.2 M values forecast for 2010 and 2011. Please explain the balance of the increase, given that "trouble call volumes have remained relatively stable" (page 13, line 25).

c) Underground Cable Locate costs are forecast to increase from the Board approved level of $10.5 M in 2008 (EB-2007-0681, C1/T2/S2, page 10) to $12.8 M in 2010 and $13.3 M in 2011 (i.e., 22% between 2008 and 2010). At the same time the number of cable locates is forecast to increase from 75,800 to 82,250 per annum (8.5%). Please explain the remaining 12% plus increase over the two year period.

d) Service Disconnect costs are forecast to increase from the Board approved level of $7.5 M in 2008 to $8.9 M in 2010, more than 18%. At the same time the number of service disconnects is forecast to increase from 10,600 to 11,600 – 9.4%. Please explain the remaining 8.5% increase over the two years.

e) Please explain the reason for the higher level of spending on Line Patrols, Wood Pole Assessment & Asset Data Collection ($16.7 M) in 2009 relative to the approved 2008 level of $13.4 M and the actual 2008 spending level of $11.4 M (pages 16-19).

f) The level of spending proposed on Line Patrols, Wood Pole Assessment & Asset Data Collection for 2010 is $15.4 M (when the needed spending on TDR is excluded). Please explain the reason for this increase over the 2008 Board-approved spending level of $13.4 M (pages 16-19).

g) Please explain why the actual Waste Management costs for 2008 are more than 20% higher ($3.7 M vs. $3.0 M) than the Board approved value (page 22).

h) The cost of customer inquiries for 2010 is $4.4 M relative to the Board approved cost of $3.5 M for 2008. However, the referenced number of inquiries in the current Application is 8,000 (page 25) versus 9,000 in EB-2007-0681 (C1/2/2, page 22). Please reconcile and provide the reasons for the increase in costs given the decline in inquiries.

i) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Line Sustaining OM&A that were considered during the prioritization process and identify the risks attributed to each.

Response

a) Please refer to Exhibit H, Tab 1, Schedule 20.

b) Please refer to Exhibit H, Tab 1, Schedule 18.

c) Approximately 6% of the increase is associated with natural escalation. The remainder of the increase is based on experience from 2007 and 2008. In those years, unit costs exceeded the 2008 Board approved amount, excluding escalation, by approximately 6%. It is expected that unit costs in one year to the next can fluctuate based on a variety of factors including average travel times to locate sites and the complexity of the locates required.

d) Approximately 6% of the increase is associated with natural escalation. The remainder of the increase is based on experience from 2007 and 2008. In those years, unit costs exceeded the 2008 Board approved amount, excluding escalation, by approximately 2%.

e) Please refer to Exhibit H, Tab 3, Schedule 66.

f) Please refer to Exhibit H, Tab 3, Schedule 66.

g) The increased costs above the 2008 Board approved level are attributed to an increased amount of waste that required handling. The increased level of expenditure will be required going forward given the new legislated requirements to retire PCB contaminated equipment thereby increasing PCB handling and destruction costs.

h) The 2010 forecast is to respond to 8,500 customer inquiries at a cost of $4.4 million. In recent years, the overall number of inquiries has been trending downwards but the average time required to respond has been increasing. This increase is attributed to more complex or time consuming demands from third parties. For example, larger

road authority projects that would constitute a single inquiry have caused Hydro One Distribution to provide more pole holds (used to secure poles during earth works or excavations) and overhead line cover up. Going forward, the upward pressure on Customer Inquiry costs is expected to continue. One reason for this is that Hydro One Distribution's joint use partners have been alerted to the red pine pole issue described on page 17 of Exhibit D1, Tab 2, Schedule 1. Expectations are that joint use partners will be inquiring about the condition of specific poles in specific locations at an increasing rate, the cost of which will be charged to the Customer Inquiries Program.

i) As illustrated on page 11 of Exhibit C1, Tab 2, Schedule 2, Lines Sustaining OM&A is broken out into the following four categories of work:

1) Trouble Call, Cable Locates, Disconnect/Reconnects
2) Line Maintenance
3) PCB Equipment & Waste Management
4) Other Services

Category 1 is entirely demand in nature, and Category 4 is largely demand driven. For these demand programs only the minimum investment level was considered.

For Category 2 (i.e. Lines Maintenance), the following table summarizes the funding levels considered.

Level	Total Cost Over 5 Yrs ($M)	Normalized Risk						
		Financial	**Reputation**	**Regulatory**	**Reliability**	**Efficiency**	**Safety & Environment**	**Customer**
Minimum	$114.9	Consequence: **Severe** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Very Likely**	Consequence: **Severe** Likelihood: **Medium**	Consequence: **Severe** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Very Likely**	Consequence: **Major** Likelihood: **Very Likely**	Consequence: **Major** Likelihood: **Very Likely**
Level 1	$137.3	Consequence: **Major** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Likely**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**
Level 2	$155.2	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Minor** Likelihood: **Likely**	Consequence: **Minor** Likelihood: **Medium**	Consequence: **Minor** Likelihood: **Likely**	Consequence: **Minor** Likelihood: **Unlikely**	Consequence: **Minor** Likelihood: **Medium**	Consequence: **Minor** Likelihood: **Likely**
Level 3	$176.4	Consequence: **Moderate** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Unlikely**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Medium**

Increasing levels allow for additional testing activities and defect corrections.

For Category 3 (i.e. PCB Equipment & Waste Management), the following table summarizes the funding levels considered.

Level	Total Cost Over 5 Yrs ($M)	Normalized Risk						
		Financial	**Reputation**	**Regulatory**	**Reliability**	**Efficiency**	**Safety & Environment**	**Customer**
Minimum	$19.5	Consequence: **Major** Likelihood: **Likely**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Moderate** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Likely**	Consequence: **Minor** Likelihood: **Remote**
Level 1	$50.3	Consequence: **Moderate** Likelihood: **Likely**	Consequence: **Major** Likelihood: **Medium**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Unlikely**	Consequence: **Moderate** Likelihood: **Medium**	Consequence: **Minor** Likelihood: **Remote**
Level 2	$60.1	Consequence: **Minor** Likelihood: **Unlikely**	Consequence: **Minor** Likelihood: **Unlikely**	Consequence: **Minor** Likelihood: **Unlikely**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Remote**	Consequence: **Minor** Likelihood: **Likely**	Consequence: **Minor** Likelihood: **Remote**

The Minimum level does not contain any PCB inspection or testing activity in the five year period. Levels 1 and 2 represent increasing levels of PCB inspection and testing.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #52 List 1

Interrogatory

Issue: #3.1 and #6.1

Reference: Exhibit C1/Tab 2/Schedule 2, pages 27-32

a) Please confirm that the Metering OM&A does not include any OM&A costs for smart meters installed after the end of 2008 (page 30). If is does, what are costs included for 2010 and 2011?

b) Please explain why there is no Smart Meter OM&A reported for 2008 and 2009 (page 28) given that in EB-2007-0681 the Board approved the inclusion of smart meter installed up to December 31, 2007 in the 2008 rate base.

c) What were the 2008 and 2009 actual OM&A expenses associated with these meters (i.e., smart meters installed prior to December 31, 2007) and were any of these costs recorded in the Smart Meter Deferral Account?

d) The Application states (page 30) that the OM&A costs for this period (presumably 2010-2011) cover work needed to operate the data collection network and deliver the necessary meter data to the MDM/R.
- What are Hydro One Networks' assumptions regarding when the MDM/R will be up and running and Hydro One Networks will be required to "deliver" data to it?
- What is the basis for these assumptions?
- Please indicate what portion of the $6.7 M for 2010 and $6.9 M for 2011 is for OM&A related directly to the smart meters installed prior to December 31, 2008 and what portion is due to the work associated with the data collection network.

e) Please explain how the "increases in 2010 and 2011 of $1.2M and $1.3 M respectively" were calculated (page 32, lines 17-19).\

f) Please provide an estimate of the 2008 actual Customer Retail Meter and Wholesale Revenue Meters OM&A excluding the expenditures on Telecom and Control (page 32, lines 4-6).

Response

a) "Customer Retail Meters" does not include any Smart Meter costs after 2008.

b) There are no smart meter OM&A costs reported for 2008 and 2009, as this is consistent with the Board Decision in EB-2007-0681, which stated "specifically forecasted smart meter operating and capital costs for 2008 should continue to be tracked in the established deferral/variance accounts".

c) The OM&A costs are $6.9M in 2008 and forecast to be $14.7M in 2009. All of these costs were recorded in the Smart Meter deferral account.

d) The MDM/R is currently operational. Hydro One plans to start delivering meter data to the MDM/R starting mid November 2009. Initially on a very limited scale to confirm end-to-end operational readiness followed by a planned ramp up in volume starting early in 2010.

The following key milestones underpin Hydro One statement above:

- Successful completion of required system integration testing with the MDM/R by September 30th 2009. – This was successfully achieved.
- Completion of the required Qualification Testing with the MDM/R by mid November 2009. This is under way and on track for completion on schedule.
- Start of meter data delivery to the MDM/R in support of end-to-end operational readiness confirmation – mid November 2009.
- Ramp up of volume in data delivery to MDM/R – early 2010

Please refer to Exhibit H, Tab 1, Schedule 143 (c) for a breakdown of the summary a breakdown of the 2010 and 2011 OM&A costs.

e) Lines 17 – 19 on page 32 is poorly worded, it should correctly read “The increases in 2010 and 2011 (i.e. to $1.2 million and $1.3 million) are attributed to the increase in the number of MIST meters and the telecom monitoring of additional distribution equipment.”

f) The actual 2008 Customer Retail Meter and Wholesale Revenue Meters OM&A cost was $6.8M

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53 List 1

Interrogatory

Issue: #3.2

Reference: Exhibit C1/Tab 2/Schedule 2, pages 32-41

a) Please provide a schedule that sets out the number of km of line cleared in each year from 2006-2009 relative to the 14,300 km planned for 2011.

b) The proposal states that the 2007 and 2008 spending levels were commensurate with an eight-year cycle whereas the 2011 spending is reflective of a seven-year cycle. What cycle period is the 2009 spending reflective of?

Response

a) Please refer to Exhibit H, Tab 1, Schedule 34.

b) The 2009 spending level is reflective of a transition from an 8-year cycle to a 7-year cycle and equals about 7.5 years.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #54 List 1

Interrogatory

Issue: #3.1 and #9.2

Reference: i) Exhibit C1/Tab 2/Schedule 3
ii) Exhibit A/Tab 14/Schedule 2, page 12

a) Are any of the costs for Data Collection, Engineering and Technical Studies recoverable from either load or generator customers?
- If yes, what is the expected cost recovery for 2010 and 2011 from load customers and from generator customers? How do these recovery amounts compare with the OEB-approved and actual amounts for 2008?
- If no, why not?

b) Hydro One Networks' Green Energy Plan includes $3 M in Development OM&A related to renewable generation connection for 2010 and 2011. Is this the $2.8 M referred to in reference (i) at page 3 (lines 24-27)? If not, please indicate how the $3 M is split between the cost categories shown in Table 1.

c) Is the $3 M in Development OM&A related to renewable generation that is included in Hydro One Networks' Green Energy Plan recoverable through the GAM under Ontario Regulation 330/09? If not, please explain why?

d) Is any of the increased spending on R&D related to generation connections included in the Green Energy Plan (reference (i), page 6, lines 5-6)? If not, why not? If yes, why is the spending not included in the Green Energy Plan?

Response

a) None of the costs for Data Collection, Engineering and Technical Studies are recoverable from load or generator customers. These costs are proactive studies done by Hydro One to support investment decisions. This work covers System Impact Studies to determine distribution reinforcement needs and collection of feeder loading data. Costs related to managing the relationship with generators and resolving operating issues, as well as proactive feeder modeling in high wind areas are also included in this program. These costs are for day-to-day activities that are not attributable to a single customer and are therefore not recovered directly from load or generator customers.

b) Yes.

c) Hydro One Distribution has not assumed that the $3 M in Development OM&A related to renewable generation included in its Green Energy Plan will be recovered through the GAM. These costs reflect the increased complexity in the day-to-day activities associated with managing the Distribution business.

d) Please see response at Exhibit H, Tab 7, Schedule 51.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #55 List 1

Interrogatory

Issue: #3.1 and #9.2

Reference: Exhibit C1/Tab 2/Schedule 4

a) Please explain more fully how Operations costs vary based on storm activity and planned outage quantities (page 8).

b) Please explain more fully how distributed generation and smart meters lead to an increase in the cost of Operations from the approved 2008 level of $9.5 M to $12.4 M in 2010.

c) Given that the increases in Operations costs and Operating Support costs are, in part, attributed to greater distributed generation – why aren't any of these cost increases captured in the proposed Green Energy Plan? How much of these increases is attributable to renewable distributed generation?

d) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Operations OM&A that were considered during the prioritization process and identify the risks attributed to each.

Response

a) Increases in planned outages and storm activity increase the work efforts of operations staff. For forced outages, phone calls from customers are used to detect and locate system outages. Once the location of the faulted equipment is determined, the OGCC dispatches repair crews, tracks crews, records response times and repair statuses and composes and distributes stakeholder and media notifications. For planned outages, staff schedule planned outages, coordinate switching, identify and notify customers of upcoming outages and respond to customer concerns.

b) In 2008, the OGCC staffing was below approved staff compliment. Additional staff are required for Distributed Generation which necessitates greater operation visibility and control of the Distribution system for the safe and reliable supply of power. (See Exhibit H, Tab 1, Schedule 28).

c) The Green Energy Plan contains only specific investments driven by the Green Energy and Green Economy Act. OM&A costs associated with an increase in the

scope of work for day-to-day activities associated with renewable generation and Smart Grid were not included in the Green Energy Plan.

d) Only minimum level funding was considered for Operations OM&A.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #56 List 1

Interrogatory

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schedule 5

a) Please explain more fully how the forecasted bad debt expense of $17.1 M for 2010 was established (page 11).

b) What are the year-to-date bad actual bad debt expenses for 2009?

c) Please explain more fully the basis for the $3 M increase in Customer Service Operations attributed to managing planned customer demand from distributed generation customers (page 4).

d) Please provide a schedule that breaks out the annual spending on Customer Service Operations into its components (as set out on pages 5-10) for the years 2006 to 2011.

Response

a) The bad debt forecast for 2010 was set based on consideration of the 2008 year-end net bad debt expense of $15.5 million and looking at past trends and economic indicators, which suggested bad debt would continue to increase. Bad debt was forecast to grow by eight per cent in 2009, and a further two per cent in 2010.

b) The actual net bad debt expense as of August 31 2009 is $13.2 million

c) The increase in Customer Service Operations costs associated with services to renewable distributed generators are :
- call handling capacity at the Customer Communications Centres
- resources to pay renewable generators for power produced, and to settle with the IESO for the difference between payments made under generator contract prices and electricity commodity price.

d) A break-out of Customer Services Operations spending reflecting the service programs billing, contact handling and collections delivered by Inergi is not available. The contract for these services is bundled.

Settlements is contracted for separately and a break out is shown in table below:

$M	2006	2007	2008	2009	2010	2011
Customer Services	36.7	37.2	37.2	37.2	39.2	38.4
Settlements	2.3	2.1	2.3	2.5	3.6	3.6
TOTAL Customer Service Operations	39.0	39.3	39.5	39.7	42.8	42.0

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #57 List 1

Interrogatory

Issue: #3.3

Reference: Exhibit C1/Tab 2/Schedule 7, pages 1-22

a) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Corporate Functions and Services that were considered during the prioritization process and identify the risks attributed to each.

b) With respect to Corporate Management (pages 3-4), please explain more fully how the requirements of the GEGEA increase the costs for this category and precisely what the cost increases are for (e.g., staff increases, external consulting, etc.).

c) With respect to Finance (page 5), the EB-2007-0681 Application included Finance costs for 2008 of $26.9 M (Total) and $12.1 M (Dx Allocation). Please restate both of these values so that they exclude Outsourcing and Enablement and are comparable to the 2010 and 2011 costs in the current Application. Please indicate how much of the adjustment is due to the transfer of Outsourcing versus Enablement.

d) Please explain the increase in (Total) Finance costs from 2008 Approved (adjusted per part (c)) to $30.4 M in 2010.

e) Please explain the increase in Hydro One Inc. Insurance Premiums from $4.9 M in 2008 to $6.5 M in 2010 (page 8).

f) Please explain the increase in (Total) Human Resource cost from 2008 Approved ($12.6 M per EB-2007-0681) to $18.1 M in 2010, particularly since many of the issues raised in the current application (e.g., staff demographics, training for new hires, etc.) were also referenced in the previous application.

g) How many new hires is Hydro One Inc. planning for 2010 and 2011 and how does this compare with the planned (per EB-2007-0681) and actual hires for 2008?

h) With respect to First Nations and Métis Relations, what are the 2008 (approved and actual) and projected 2009 costs – both Total and Distribution (pages 13-14)?

i) With respect to Regulatory Costs (page 17, lines 21-23), the Application states that the $2.1 M and $4.8 M for 2008 and 2009 respectively were included in "Other Distribution Costs" but then goes on to state that the values include the costs of Transmission rate applications. Please reconcile and clarify what the Distribution Business' share of Incremental and Major Rate Hearing Costs was for 2008 and 2009.

j) With respect to Corporate Security (page 21), has the new Theft of Electricity Investigation Program led to increased recoveries for theft of power or an (implicit) reduction in losses? If yes, please indicate where these "savings" are captured in the application. If not, what is the justification for the program?

Response

a) Approximately 75% of Hydro One's costs are managed through the investment prioritization process. The remaining costs which include Corporate Functions and Services (CF&S) are approved by the Hydro One Executive Committee through specific submission. Each CF&S group conducts its own risk assessment as part of the corporate overall risk management process.

b) The corporate management function includes a newly created role of Special Advisor to the President and CEO that will provide strategic support on Hydro One matters relating to the GEGEA.

c) The 2008 figures for Finance as reported in EB-2007-0681 do not include Outsourcing Services (which was included in Asset Management) or Enablement (new function created in 2008 and reflected in the 2008 historic levels).

d) The reasons for the increase in total Finance costs from 2008 (per approved amounts in EB-2007-0681) to 2010 are explained in Exhibit C1, Tab 2, Schedule 7, Page 5.

e) Please refer to Exhibit H, Tab 1, Schedule 40.

f) Please refer to Exhibit H, Tab 10, Schedule 35 (c).

g) Within CCFS, headcount for regular staff personnel in 2008 was very close to the levels budgeted. The plan is to add roughly 55 positions through 2010 and 2011 compared to 2008.

h) Please refer to the table below for First Nations and Métis Relations. In the EB-2007-0681 Application, there was no Board-approved amount for First Nations and Métis Relations ("Aboriginal Relations"). All amounts in the table below are reported in $ millions:

Description	2008 Actual	2008 Approved	2009 Bridge
Distribution	0.1	0	0.7
Transmission	0.2	0	0.8

i) The total 2009 incremental major rate hearing costs in 2009 are approximately $4.8 million of which $2.0M is included in Distribution.

j) The Theft of Electricity Investigation Program has resulted in increased detection of theft of power which will implicitly reduce future losses. Though the program has produced some recoveries, the potential future recoveries are not included in this application as it is Hydro One's belief that the primary future benefit is reduced losses.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #58 List 1

Interrogatory

Issue: #9.2

Reference: Exhibit C1/Tab 2/Schedule 7, pages 1-22

a) For a number of the CFFS cost areas the GEGEA is cited as a reason for cost increases in 2010 and 2011. However, the proposed Green Energy Plan does not include any of these costs or associated activities. Please reconcile.

b) Please provide a schedule that sets out for each CCFS function/service area the 2010 and 2011 Total Cost and Dx Allocation attributable to the GEGEA and, more specifically, smart grid and renewable energy generation.

Response

a) Please refer to Exhibit H, Tab 12, Schedule 12.

b) Although the core activities of the groups comprising CCFS are fundamentally unchanged compared to the previous application, the requirements of the GEGEA, Smart Grid and renewable energy generation are contributing to increased overall work. However, the underlying activities in the shared services model are not aligned with specific activities associated with GEGEA, Smart Grid and renewable energy generation and consequently, an attribution of costs to these programs is not possible.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #59 List 1

Interrogatory

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schedule 7, pages 22-25

a) With respect to the Environmental Provision, the Application states that the "resultant impact on OM&A expense is nil". In Exhibit C1/Tab 2/Schedule 2 the increase in 2010 OM&A costs attributed to the new Federal Government's PCB regulations is $3.8 M for Stations (page 8) and $5.5 M for lines (page 22). However, the increase in the provision from 2008 is only $3.7 M – please reconcile.

Response

Please note that the amounts included in Exhibit C1, Tab 2, Schedule 2 represent planned waste management program costs for lines and stations, not increases.

PCB spend has increased approximately $4M between 2008 and 2010 which corresponds to the approximately $4M increase in the environmental provision from 2008 to 2010. The overall increase in the amounts included in the environmental provision reflect increased expenditures required to comply with the new Federal PCB regulations that came into force in late 2008.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #60 List 1

Interrogatory

Issue: #3.4

Reference: Exhibit C1/Tab 2/Schedule 8

a) Please confirm that the totals shown in Table 1 for 2006-2011 are for Hydro One Networks. Please also confirm that the Asset Management function does not provide any services/support to Hydro One Remotes Inc. or other affiliates.

b) For Strategy and Business Development (page 5), please explain the new activities that lead to an increase in costs from $6.3 M in 2008 to $11.0 M in 2010.

c) With respect to System Investment (page 7), please confirm that for the EB-2007-0681 Application the cost of "Processes and Policies" were part of System Investment.

d) With respect to System Investment (page 7), please explain what leads to the increase in the portion of costs allocated to Distribution from less than 25% in 2008 (EB-2007-0681, C1/T2/S6, page 41) to almost 50% in 2010.

e) Real Estate and Facilities costs increase between 2008 and 2010 by 38% (page 16). The application makes reference to expanded work space needs due to increased staff levels (page 18). Please provide increases in year-end staff count or other metrics over the same period that would support this level of increase.

f) With respect to Contracts and Business Relations, please explain the more than 25% increase between 2008 and 2010 (page 20).

g) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for the following functions/services that were considered during the prioritization process and identify the risks attributed to each:
   - Strategy and Business Development
   - System Investment

   If Asset Management OM&A was considered on a envelop basis during the investment prioritization process, please describe the different levels of overall funding that were considered during the prioritization process and the relative risks attributed to each.

Response

a) We can confirm that the totals shown in Table 1, (historic year 2006 to test year 2011) found on page 3 of Exhibit C1, Tab 2, Schedule 8 represents Hydro One Networks. We also confirm that the Asset Management function does not provide any services/support to Hydro One Remotes Inc. or any other affiliates.

b) The main activities leading to the increases are: increased spending on property, boiler and machinery insurance, increased activities relating to the design and implementation of existing OPA and Ministry of Energy funded CDM initiatives, and increased activities to develop and implement Hydro One internally funded CDM initiatives, increased activities to support the corporate vision in the rapidly changing business environment, increased activities relating to overseeing the Customer Advisory Board, and increased activities relating to the efficient leveraging of the transmission and distribution systems, including smart grid.

c) We can confirm that "Processes and Policies" were part of System Investment prior to 2008 for the EB-2007-0681 Application.

d) Groups within Asset Management including System Investments, provides support to both the transmission and distribution businesses, based on the demands and requirements of the overall capital and OMA work programs. The overall increases in costs are driven by additional efforts to replace the end-of-life assets across the transmission and distribution systems, as well as the Green Energy initiatives. The upward pressure on System Investment costs can be seen on page 8 in Exhibit C1, Tab 2, Schedule 8. Overall, System Investment costs have increased in 2009, 2010 and 2011. The increases in cost allocations to Distribution in 2009, 2010 and 2011 resulted from specific focus on initiatives such as - smart meter and smart grid, replacement of end-of-life assets, and the expected demand resulting from the Green Energy initiatives

e) The 38% increase in Real Estate and Facilities costs in 2010 over 2008 represents the ongoing, as well as the additional activities being undertaken by the function. This increase is being driven by the demands and the requirements for Real Estate and Facilities to support the increased growth in the transmission and distribution capital and OMA work programs. The activities driving the costs increases for Real Estate Services can be found in Exhibit C1, Tab 2, Schedule 8, pages 16 to 17, and the activities driving the costs increases for Facilities can be found on pages 18 to 20 of the same exhibit.

The level of costs increases forecasted for test years 2010 and 2011 are not exclusively driven by planned staff increases across the organization. Instead, costs are forecasted for ongoing and increased activities being undertaken by Real Estate and Facilities such as – the management of Hydro One new and existing rights

portfolio, management and upkeep of the transmission and distribution stations, management and upkeep of over 90 administrative and service centre locations including the OGCC, the London Call Centre and head office, and management of leases and lease renewals across the province. The support of the Green Energy initiatives also resulted in increased costs.

Hydro One planned staff increases to support the demands and the requirements of the growing transmission and distribution capital and OMA work programs from 2008 to 2010 can be seen in the response at Exhibit H, Tab 7, Schedule 67.

f) The drivers behind the costs increases of more than 25% in 2010 over 2008 are related the increased activities to fulfill the requirements of the growing transmission and distribution work programs, such as – additional efforts to manage the relationships with our large segment distribution and transmission customers, additional efforts to manage customer contracts and to address customer communications, and the expected increases in distributed generation requests and connections.

g) Please refer to the response at Exhibit H, Tab 7, Schedule 51.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #61 List 1

Interrogatory

Issue: #9.2

Reference: Exhibit C1/Tab 2/Schedule 8

a) The Application states (page 4) that the GEGEA has an impact on the Asset Management spending for 2010 and 2011. However, none of the costs associated with Asset Management are included in the proposed Green Energy Plan. Please reconcile.

b) Please provide a schedule that sets out for each Asset Management function/service area the 2010 and 2011 Total Cost and Dx Allocation attributable to the GEGEA and, more specifically, smart grid and renewable energy generation.

Response

a) The Green Energy Plan as included in Exhibit A, Tab 14, Schedule 2 provides a high-level overview of the major 'green' programs and initiatives that Hydro One will be undertaking.

This exhibit is intended to summarize only the program and project investments required because of the Green Energy Act.

The Green Energy Plan Evidence focuses on direct program costs. Indirect costs in support of the GEP such as Asset management and CF&S costs will remain in their respective functions and are not charged directly to the GEP initiatives.

b) The schedule is set out below.

Asset Management Function - Estimated GEA related costs 2010-2011 ($ Millions)

Function/Service	Total 2010	Total 2011	GEA Portion* 2010	GEA Portion* 2011	Allocation to Distribution 2010	Allocation to Distribution 2011
Strategy & Business Development	11.0	12.5	1.3	2.8	0.9	2.0
System Investment	37.1	38.6	0.0	1.5	0.0	0.8
Work Program Optimization	4.5	4.9	0.4	0.8	0.1	0.2
Business Integration	14.2	16.3	0.8	2.9	0.4	1.4
Business Transformation	2.4	2.5	0.0	0.1	0.0	0.0
Real Estate & Facilities	57.8	59.9	3.4	4.1	1.7	2.1
Contract & Business Relations	6.2	6.3	0.3	0.4	0.1	0.1
Processes and Policies	4.5	4.6	0.0	0.0	0.0	0.0
Total Costs	**137.9**	**145.7**	**6.2**	**12.5**	**3.1**	**6.5**

***** GEA Portion is estimated and smart grid and renewable energy generation related work is not specifically identified.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #62 List 1

Interrogatory

Issue: #3.4

Reference: Exhibit C1/Tab 2/Schedule 9

a) The 2009 review undertaken by Black and Veatch (Exhibit C1/Tab 5/Schedule 1) addresses CCFS costs and Asset Management costs but does not appear to cover Shared Services for IT. Please confirm if this is the case.
   - If IT costs were addressed, please indicate where the discussion and conclusions can be found.
   - If not, why not and what process was assess the reasonableness of the allocation of IT costs to Distribution.

b) For OMS Incremental Sustainment, the total costs for 2010 are less than those include in EB-2007-0681 for 2008 ($6.1 M vs. $6.6 M). However, the Distribution portion of the costs increases from $3.8 M to $4.9 M. Please explain the significant shift in cost responsibility to the Distribution business.

Response

a) Information Technology shared services costs were addressed in Black & Veatch's (B&V) report included in the prefiled evidence under Exhibit C1, Tab 5, Schedule 1, Attachment 1. Information Management and Information Technology Costs are referenced in Exhibit A, page A-2 of B&V's report and are grouped in "Corporate Services". As stated on page A-2 of the report, Information Management and Information Technology Costs comprise Enterprise IT Architecture and Governance, Business Analysis and Information Management, Project Management, Inergi & Telecom Services Management. Inergi IT costs are referenced on page A-5 under "Inergi Functions". Section II of the report addresses the procedures performed by B&V and Section III presents their conclusions with respect to Hydro One's application of the B&V shared cost allocation methodology.

b) In the 2008 Dx rate filing evidence, the breakdown of the sustainment distribution spend for Base, OMS and Incremental sustainment was calculated using the overall ratio for sustainment (57.3%) rather than the specific line item ratios. In the 2010 test year, the Dx sustainment distribution was calculated using the specific row by row ratios. For OMS sustainment the proper ratio is 79.8%.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #63 List 1

Interrogatory

Issue: #3.3

Reference: Exhibit C1/Tab 2/Schedule 9

a) With respect to IT Sustainment, please explain why the actual 2008 costs are 20% higher (i.e., $51.4 M vs. $42.8 M) than those forecast in EB-2007-0681 (C1/T2/S6, page 59).

b) What was the COLA cost factor for 2008 – both the value used for EB-2007-0681 and the actual value?

c) Does a change in the COLA cost factor from $9.9 M in 2009 to $11.3 M in 2010 mean that Base IT Sustainment Costs increase by $1.4 M? If not, please explain how the change in COLA cost factor influences annual costs.

d) If the response to part b) is yes, please explain why the changes for Base IT Sustainment costs in 2010 and 2011 do not reconcile with the changes in the "cost factor".

e) With respect to Other Incremental Sustainment (page 4), please explain why the actual costs for 2008 ($14.8 M) are 45% higher than those forecasted for 2008 in EB-2007-0681 (C1/T2/S6, page 59).

f) How much of the overall increase in Other Incremental Sustainment between 2008 (actual) and 2010 is due to Cornerstone Phase 1 and Phase 2?

g) With respect to Voice Services, what are the "new site builds" (page 18)? How do they plus the increased head count (page 18, line 20) result in an almost 80% increase in costs over approved 2008 levels from EB-2007-0681 (i.e., $6.1 M vs. $3.4 M)?

h) With respect to IT Management & Project Control Expenditures, costs increase by more than 30% between 2008 and 2009 even after excluding the new Enablement costs for 2009. Please explain the reason for the increase.

i) With respect to IT Management & Project Control Expenditures, what is the additional cost allowance included in 2010 and 2011 related to the Inergi Outsourcing contract reaching end of term (page 21, lines 11-12) and what was the cost of this contract for 2008 and 2009?

j) With respect to IT Management & Project Control Expenditures and the $16.4 M increase between 2008 and 2010 ($23.9 M vs. $7.5 M), how much of this increase remains unexplained after consideration is given to i) the transfer of the Enablement Department ($6.6 M), ii) the transfer of the Information Assets Department ($5.2 M) and iii) the increased allowance for the termination of the Inergi contract? If more than $0.5 M – please provide an explanation.

k) With reference to page 22 (lines 15-20), please indicate where in Exhibit C1/Tab 2/Schedule 8 (i.e., Asset Management) it is acknowledged that the Information Asset Department was transferred out to IT and the costs for 2010 (and onward) reduced accordingly.

Response

a) The actual 2008 IT Sustainment cost are 20% higher (ie, $51.4M vs $42.8M) than those forecasted in EB-2007-068 primarily due to:

- The additional IT infrastructure delivered from the Cornerstone Phase 1 project was greater than originally planned.
- The finalization of increase in COLA (Cost of Living Adjustment).
- The increased support cost as a result of the deployment of a second mainframe as an enhancement to the Disaster/Recovery program.
- The additional headcount in HelpDesk and Deskside support to handle the increased volume of calls/contacts and to increase level of service to IT user community.

b) The COLA cost factor for 2008 used in EB-2007-0681 was 15.02%, whereby the actual COLA cost factor for 2008 was 16.32%. Note that this COLA cost factor is cumulative relative to the start of the Inergi service provider contract and the year over year increase is based on two labour economic indices published by Statistics Canada. The actual increase in 2008 over 2007 was 1.30% greater than the increase assumed when the 2008 Budget was constructed, resulting in the higher overall factor.

c) No, COLA is not the only cost factor. The actual Base IT Sustainment Cost is a total of all components (e.g. COLA, PST, Pension, Inergi Base services).

d) Not applicable – see response to c).

e) The forecast for Other Incremental Sustainment for 2008 in EB-2007-0681 was $10.2M and the actual for 2008 was $14.8M, an increase of 45%. The increase is mainly due to:

- The increase in licensing cost for new Oracle technology tools to support audit and security requirements.
- The increase in actual cost for the application support of Cornerstone Phase 1 for the implementation of SAP.
- The increase in the Work Execution Program application support.
- The increase in additional Microsoft licenses and maintenance for desktop and server software due to staff and headcount growth realized.

f) In 2008, incremental SAP application support costs for the partial year was $2.2M.

With full-year Cornerstone Phase 1 and Phase 2 in-service in 2010, total incremental SAP application maintenance is estimated to be $10.0M.

g) The new site builds planned for 2010 are:

- Expand and renovate floors in the downtown headquarter (483 Bay Street);
- Build new metering facility at Matheson Boulevard;
- Add modular training facilities at Kleinberg;
- Commission new sites in the province (e.g. Picton, Kenderry gate, Quinte).

The Voice Services cost includes monthly charges and usage fees for voice grade business telecom (local and long distance) which are primarily driven by personnel headcounts. The increase in Voice Services cost are largely due to the Green Energy and Green Economy Act (GEGEA) work program.

h) Excluding the Enablement costs for 2009, IT Management & Project Control costs increased by $2.3M, from $7.5M in 2008 to $9.8M in 2009. The increase is primarily due to:

- The transfer of the Finance Control and Acquisition department from Corporate Finance into IT ($0.6M)
- Hiring of additional IT personnel to support execution of the enterprise work programs serving program management, architecture, and outsourcing management roles. ($0.4M)
- Additional services for assessing the outsourced telecom service arrangement, assessing the enterprise content management strategy, development of architectural (SAP) roadmap and IT strategy, various security initiatives, and project management Quality Assurance methodology ($1.3M).

i) The estimated cost allowance relating to the Inergi Outsourcing contract is $0.4M. The IT portion of the Outsourcing contract for 2008 was $62.2M and for 2009 the forecast is $68.0M.

j) Excluding the Enablement Department and Information Assets Department transfer, and the increased allowance for the termination of the Inergi contract, there remains $4.6M increase between 2008 and 2010. This is primarily due to:

- Transfer to the Finance Control and Acquisition department from Corporate Finance into BIT (Business Information Technology) (+$0.6M)
- Hiring of additional IT personnel to support execution of the enterprise work programs serving program management, architecture, and outsourcing management roles. (+$0.4M)
- Additional resources in 2010 for the support of Business Intelligence functionality as part of Cornerstone Phase 2 and Smart Grid initiatives. (+$0.5M)
- Allowance for escalation of labour costs and benefits for existing staff. (+0.4M)
- Additional services for assessing the outsourced telecom service arrangement, assessing the enterprise content management strategy, development of architectural (SAP) roadmap and IT strategy, various security initiatives, and project management Quality Assurance methodology ($1.3M).
- Assessments for the upgrading of Microsoft desktop, office and server technology, Unified Communication, assessment on the implementation of security enhancement and operations centre initiatives, roll out of end-user and professional training, refresh of internal portal intranet/extranet technology, and increase in PMO resources for program management. (+$1.4M)

k) The Information Asset department reduction is in the evidence Exhibit C1, Tab 2, Schedule 8, page 3, Table 1 under Asset Management in the Business Integration division.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #64 List 1

Interrogatory

Issue: #2.2

Reference: Exhibit C1/Tab 2/Schedule 11

a) For each Cost of Sales Category (page 1), please indicate what the corresponding revenue is for the work. In particular, is the $3.0 M in revenue for 2010 New Connects/Upgrades shown in Exhibit E1/Tab 1/Schedule 2, page 3 directly associated with the $2.7 M in costs shown here? Similarly, is the 2010 Other External Work of $6.2 M directly associated with the Lines-Contestable Work shown here? If not, please explain the differences.

Response

The corresponding revenues are included in the table below. Yes, the $3M in revenue for 2010 New Connects/Upgrades shown in Exhibit E1, Tab 1, Schedule 2, page 3, table 2 is directly associated with the cost of sales amount of $2.7 M shown in Exhibit C1, Table 2, Schedule 11, page 1, table 1.

The amount of $6.2M in test year 2010 for other external work shown in Exhibit E1, Tab 1, Schedule 2, page 3, table 2 is directly associated with the cost of sales amount of $5.2M shown in Exhibit C1, Table 2, Schedule 11, page 1, table 1 for Lines – Contestable Work.

	$M's					
	2006	2007	2008	2009	2010	2011
Unregulated Revenues						
New Connects/Upgrades & Other Contestable Work	**6.6**	**7.9**	**8.4**	**8.2**	**9.2**	**9.3**
New Connects & Upgrades	4.3	4.9	3.3	3.2	3.0	3.1
Total A+B	**2.3**	**3.1**	**5.1**	**5.0**	**6.2**	**6.2**
A - Lines - Other Contestable Work	1.1	2.0	3.9	3.8	5.0	5.0
B - Health, Safety & Environment Training	1.2	1.1	1.2	1.2	1.2	1.2
Non-Regulated Miscellaneous Revenue	**0.9**	**0.8**	**0.0**	**1.4**	**1.7**	**1.7**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #65 List 1

Interrogatory

Issue: #3.7

Reference: Exhibit C1/Tab 2/Schedule 12

a) Please explain the decrease in Rights Payments for 2008 and why it is not maintained going forward.

Response

The 2008 reflects a one time reduction due to timing of payments issued. Hydro One expects the rights payments to be in the range of approximately $0.3M across the bridge and test years.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #66 List 1

Interrogatory

Issue: #3.5

Reference: i) Exhibit C1/Tab 3/Schedule 2
ii) EB-2008-0272, Exhibit I/Tab 1/Schedule 19
iii) EB-2008-0272, Exhibit I/Tab 6/Schedule 37

a) Please update the schedule provided in Reference (ii) so that it covers the years 2006 to 2011.

b) Please update the schedule provided in Reference (iii) – part a-i) (i.e. Splitting Wages between Capital and OM&A) so that it covers the period 2006-2011.

c) With respect to Reference (i), page 9 (lines 20-22), please indicate the basis for the 33% and 16% figures (i.e., show the data values used and their sources).

d) If practical, please prepare comparisons between Hydro One Networks and Hydro One – Brampton Networks for PWU Staff and MP Staff positions similar to those found on pages 14 and 15.

Response

a) Please see Attachment 1.

b) Please see Attachment 2.

c) Hydro One work program consists of both Transmission and Distribution work. The total Networks work program is $2,552 million in 2009 and $3,401 million in 2011. This is the sum of the Distribution work volumes in the EB-2009-0096 prefiled evidence submitted July 13, 2009 and the Transmission work volumes in the current Hydro One Business Plan (as provided in Exhibit H, Tab 13, Schedule 1). These work volumes include smart meter program expenditures, capital expenditures assumed to be funded through the Global Adjustment Mechanism, environmental provision costs and deferred Transmission Development OM&A costs.

d) Please see Attachment 3.

2006

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay	Incentive as % of Base
PWU Reg	2,862	262,294,356	202,358,005	53,457,558	4,200	6,474,593	70,705	0.00%
SOCIETY Reg	687	65,175,105	62,356,208	1,466,238	0	1,352,659	90,766	0.00%
MCP Reg	469	59,489,433	49,471,987	55,767	4,397,964	5,563,716	105,484	8.89%
Total Reg	**4,018**	**386,958,894**	**314,186,200**	**54,979,563**	**4,402,164**	**13,390,968**	**78,195**	
PWU Temp	110	2,509,937	2,582,255	111,845		-184,162	23,475	0
Society Temp	45	1,269,193	1,336,917	19,831		-87,555	29,709	0
MCP Temp	7	218,523	215,324	1,165		2,035	30,761	0
Total Temp	**162**	**3,997,654**	**4,134,495**	**132,841**		**-269,682**	**25,522**	
CASUAL	1121	68,368,828	49,638,768	11,375,466		7,354,595	44,281	0
TOTAL	**5301**	**459,325,376**	**367,959,463**	**66,487,869**	**4,402,164**	**20,475,881**	**69,413**	

2007

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay	Incentive as % of Base
PWU Reg	3,084	276,571,977	226,331,027	48,126,236	500	2,114,215	73,389	0.00%
SOCIETY Reg	712	67,398,484	65,268,684	2,332,197	6,500	(208,898)	91,670	0.01%
MCP Reg	516	67,420,494	56,665,378	63,511	6,636,752	4,054,852	109,817	11.71%
Total Reg	**4,312**	**411,390,956**	**348,265,090**	**50,521,944**	**6,643,752**	**5,960,170**	**80,766**	
PWU Temp	143	2,826,419	3,116,973	50,825		-341,379	21,797	0%
Society Temp	92	3,019,335	3,350,706	19,862		-351,234	36,421	0%
MCP Temp	8	297,149	290,565	0		6,584	36,321	0%
Total Temp	**243**	**6,142,903**	**6,758,244**	**70,687**		**-686,029**	**27,812**	
CASUAL	1338	77,992,251	59,693,098	10,343,821		7,955,332	44,614	0
TOTAL	**5893**	**495,526,109**	**414,716,432**	**60,936,452**	**6,643,752**	**13,229,473**	**70,374.42**	

2008

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay	Incentive as % of Base
PWU Reg	3,202	297,833,419	237,235,359	51,987,917		5,924,105.15	74,089.74	0.00%
SOCIETY Reg	945	86,896,084	80,956,623	3,485,454		(232,030.09)	85,668.38	0.00%
MCP Reg	567	76,768,050	63,928,396		8,073,994	10,153,617.45	112,748.49	12.63%
Total Reg	**4,714**	**461,497,554**	**382,120,378**	**55,473,371**		**15,845,693**	**81,060.75**	
PWU Temp	156	3,720,781	3,932,868	61,875		-273,963	25,210.70	0.00%
Society Temp	68	2,899,699	2,988,034	30,367		-118,701	43,941.67	0.00%
MCP Temp	12	746,558	705,783	0		6,847	58,815.23	0.00%
Total Temp	**236**	**7,367,037**	**7,626,685**	**92,242**		**-385,818**	**32,316.46**	0.00%
CASUAL	1597	97,252,291	74,314,292	12,197,874		10,740,125	46,533.68	0.00%
TOTAL	**6547**	**566,116,882**	**464,061,355**	**67,763,487**	**8,073,994**	**26,200,000**	**70,881.53**	

2009

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay	Incentive as % of Base
PWU Reg	3,382	320,845,988	260,132,508	55,633,899		5,079,580.06	76,916.77	0.00%
SOCIETY Reg	1,147	105,822,873	101,902,654	4,283,592		(363,373.39)	88,842.77	0.00%
MCP Reg	656	96,426,378	75,468,898		8,900,000	12,057,479.39	115,044.05	11.79%
Total Reg	**5,185**	**523,095,239**	**437,504,061**	**59,917,491**	**8,900,000**	**16,773,686**	**84,378.80**	
PWU Temp	172	4,289,825	4,570,272	96,561		-377,008	26,571.35	0.00%
Society Temp	75	3,322,020	3,439,819	45,778		-163,577	45,864.25	0.00%
MCP Temp	13	793,278	783,923	2,234		7,120	60,301.79	0.00%
Total Temp	**260**	**8,405,123**	**8,794,014**	**144,573**		**-533,464**	**33,823.13**	
CASUAL	2011	125,299,638	97,601,925	14,537,935		13,159,778	48,534.03	0.00%
TOTAL	**7456**	**656,800,000**	**543,900,000**	**74,600,000**	**8,900,000**	**29,400,000**	**72,947.96**	

2010

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay	Incentive as % of Base
PWU Reg	3,754	372,678,682	308,707,183	61,219,886		2,751,613.00	82,234.20	0.00%
SOCIETY Reg	1,362	132,734,188	128,733,487	5,252,602		(1,251,901.37)	94,517.98	0.00%
MCP Reg	732	111,637,923	87,678,697		10,600,000	13,359,225.67	119,779.64	12.09%
Total Reg	**5,848**	**617,050,793**	**525,119,367**	**66,472,488**	**10,600,000**	**14,858,937**	**89,794.69**	
PWU Temp	189	5,298,943	5,741,521	142,912		-585,490	30,378.42	0.00%
Society Temp	82	3,933,478	4,120,509	66,072		-253,103	50,250.11	0.00%
MCP Temp	14	924,339	911,691	5,245		7,404	65,120.77	0.00%
Total Temp	**285**	**10,156,760**	**10,773,721**	**214,229**		**-831,189**	**37,802.53**	
CASUAL	3419	222,292,448	181,206,912	20,913,284		20,172,252	52,999.97	0.00%
Total	**9552**	**849,500,000**	**717,100,000**	**87,600,000**	**10,600,000**	**34,200,000**	**75,073.28**	

2011

REPRESENTATION	TOTAL NO. EMPLYS	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other	Average Base Pay	Incentive as % of Base
PWU Reg	3,909	401,769,014	334,886,365	64,527,180		2,355,469	85,670.60	0.00%
SOCIETY Reg	1,396	141,139,915	137,258,755	5,538,033		-1,656,873	98,322.89	0.00%
MCP Reg	748	**117,693,003**	91,664,190	32,323	12,200,000	13,796,490	122,545.71	13.31%
Total Reg	**6,053**	**660,601,932**	**563,809,310**	**70,097,536**	**12,200,000**	**14,495,085**	**93,145.43**	
PWU Temp	208	6,183,624	6,709,901	163,587		-689,864	32,259.14	-
Society Temp	90	4,523,232	4,745,429	75,263		-297,460	52,726.99	-
MCP Temp	15	1,034,600	1,020,657	6,243		7,700	68,043.77	-
Total Temp	**313**	**11,741,455**	**12,475,987**	**245,093**		**-979,624**	**39,859.38**	
CASUAL	3879	261,756,613	215,514,703	23,157,371		23,084,539	55,559.35	-
TOTAL	**10,245**	**934,100,000**	**791,800,000**	**93,500,000**	**12,200,000**	**36,600,000**	**77,286.48**	

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 and variable for data restrictions

Total Wages
Hydro One Networks Inc.

M$	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test	2011 Test
OM&A	281.4	302.3	336.3	387.5	500.2	550.5
Capital	177.9	193.2	229.8	269.3	349.3	383.6
Total	**459.3**	**495.5**	**566.1**	**656.8**	**849.5**	**934.1**

Power Workers' Union – Wage Scale Comparisons, 1999 and 2009

	1999	2009	Percent Change
Mechanical Maintainer/Regional Maintainer - Mechanical			
Hydro One	$ 28.23	$ 38.30	36%
OPG	$ 29.08	$ 44.72	54%
Bruce Power	$ 29.08	$ 50.73	74%
HON Brampton	-	-	-
Shift Control Technician/Regional Maintainer - Electrical			
Hydro One	$ 28.23	$ 38.30	36%
OPG	$ 30.31	$ 44.72	48%
Bruce Power	$ 30.31	$ 50.88	68%
Substation Electrician	$25.83	$ 35.75	
Clerical – Grade 56 (based on 35-hour work week)			
Hydro One	$ 21.46	$ 29.12	36%
OPG	$ 21.46	$ 28.56	33%
Bruce Power	$ 21.46	$ 31.62	47%
Hydro One Brampton (IBEW)	$ 17.97	$ 24.46	36%
Clerical – Grade 58 (based on 35-hour work week)			
Hydro One	$ 24.20	$ 32.84	36%
OPG	$ 24.20	$ 34.79	44%
Bruce Power	$ 24.20	$ 35.65	47%
Hydro One Brampton (IBEW)	$ 22.00	$ 29.42	34%
Regional Field Mechanic/Transport & Work Equipment Mechanic			
Hydro One	$ 26.20	$ 35.56	36%
OPG	$ 26.20	$ 44.72	71%
Bruce Power	$ 26.20	$ 42.58	63%
Hydro One Brampton (CAW)	$ 25.01	$ 34.65	39%
Stockkeeper			
Hydro One	$ 23.27	$ 33.15	42%
OPG	$ 23.27	$ 34.79	50%
Bruce Power *	$ 23.27	$ 39.87	71%
Hydro One Brampton (CAW)	$ 20.35	$ 28.42	40%
Labourer			
Hydro One	$ 19.03	$ 25.82	36%
OPG	$ 19.03	$ 34.79	83%
Bruce Power *	$ 19.03	$ 39.87	110%
Hydro One Brampton (CAW)	$ 15.11	$ 21.40	42%

**** Assumes that the position falls within the Civil Maintainer II classification and corresponding wage rate.***

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #67 List 1

Interrogatory

Issue: #3.5

Reference: Exhibit C1/Tab 3/Schedule 2, Appendix A

a) Please explain how the pension costs are allocated between transmission and distribution (page 2).

b) Could a similar methodology be used to reasonably split Hydro One Networks' Total Wages cost between transmission and distribution? If not, why not?

c) If the response to part (b) is yes, please perform the analysis to split the Hydro One Networks' wages as presented in response to Question #66, part (b).

Response

a) Pension costs are allocated between transmission and distribution based on their respective portion of estimated base pensionable earnings. This is based on standard labour charge rates and other allocation methodologies developed to assign costs consistent with work effort (e.g. time studies and B&V common cost allocation).

b) Yes.

c) 2010 Wages: $849.5M
Tx: 42%* $356.8M
Dx: 58%* $492.7M

2011 Wages: $934.1M
Tx: 42%* $392.3M
Dx: 58%* $541.8M

* allocations based on Exhibit C1, Tab 3, Schedule 2, Appendix A, page 2

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #68 List 1

Interrogatory

Issue: #3.4

Reference: Exhibit C1/Tab 5/Schedule 1

a) The Application states that B&V was commissioned to update the methodology used to allocate common costs (page 1). The Application goes on (page 2) to discuss the impact of updating the cost drivers. Please clarify whether the referenced to "updating the cost drivers" means i) simply that the values of the defined drivers were updated to reflect more recent data or ii) the actual cost drivers used were reviewed.

b) With respect to part (a), please provide a schedule that sets out all instances where the actual cost driver used (as oppose to simply the value of the driver) was changed and in each case indicate:
- The cost category involved
- The total 2010 and 2011 costs
- The impact on the allocation of distribution of changing the driver
- The rationale for the change.

c) Please provide a schedule that breaks down the $148 M in 2010 Distribution CF&S costs reported in Exhibit C1/Tab 5/Schedule 1/Attachment 1, page 10 into sufficient detail that it can be reconciled with the OM&A costs proposed in the Application and provide the reconciliation. For example, the schedule should show the contribution of the CF&S costs assigned to Distribution to each of the Shared Services costs proposed for Distribution as set out at Exhibit C1/Tab 2/Schedule 6, page 3. Similarly, it should show the contribution of allocated CF&S costs to the OM&A proposed for Asset Management and Customer Care.

Response

a) The reference to the update of cost drivers in Exhibit C1, Tab 5, Schedule 1 constitutes both the update of driver values to reflect more recent data and the review of cost driver assignments as outlined in the report from B&V.

b) The following table summarizes the impact of changes to cost driver assignments by cost category in the current application for the years 2010 and 2011. In all cases, the change in the driver assignments were discussed and reviewed with B&V:

2010 Impact (in $millions):

Cost Category	Impact to Distribution	Impact to Transmission	Impact to Others	Total
Finance	0	0.1	-0.1	0
Information Technology	0.2	-0.1	-0.1	0
Total	0.2	0	-0.2	0

2011 Impact (in $ millions):

Cost Category	Impact to Distribution	Impact to Transmission	Impact to Others	Total
Finance	0	0.1	-0.1	0
Information Technology	0.3	-0.2	-0.1	0
Total	0.3	-0.1	-0.2	0

c) Please refer to the chart below for the breakdown of 2010 Distribution costs (in $ millions):

Description	CCFS Distribution (B&V report)	Other Costs	Total Distribution (2)
CCFS Costs	47.5		47.5
Asset Management	1.6	66.7	68.3
Information Technology	57.8	21.3	79.1
Cornerstone		(4.6)	(4.6)
Cost of Sales		9.6	9.6
Other OM&A		(107.8)	(107.8)
Subtotal	**106.9**		**92.1**
Inergi costs reported in Customer Care	41.1		
Total	**148.0 (1)**		

i. per Exhibit C1, Tab 5, Schedule 1, Attachment 1, page 10
ii. per Exhibit C1, Tab 2, Schedule 6

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #69 List 1

Interrogatory

Issue: #3.4

Reference: Exhibit C1/Tab 5/Schedule 2

a) Page 1 (lines 20-23) makes reference to B&V being commissioned to update the capital overhead methodology. It also refers to the 2010-2011 rates being calculated consistent with this revised methodology. The B&V Report (Attachment 1, page 1) states that the methodology used conforms to the OEB-accepted methodology as opposed to stating that the OEB-accepted methodology is used.
   - Is the methodology (as opposed to the data inputs) used in this application the same as that used in EB-2007-0681 and accepted by the OEB?
   - If not, please provide a description of any changes to the "methodology" (as opposed to the inputs) used for this Application versus the methodology used in EB-2007-0681. In doing so, please explain the reasons for the changes and the overall impact on the capitalization rates for 2010 and 2011. Note: If B&V prepared a separate report outlining the revised methodology please provide it.

b) With respect to Attachment 1, Appendix A, page 1 – please provide the equivalent schedule with the years 2008 (actual) and 2009 (forecast).

Response

a)

i – The methodology used in this application is the same as that used in EB-2007-0681 except for the application of the E-factor adjustment. Refer to EB-2009-0096- Exhibit C1/Tab 5/Schedule 2/Page 11/Section 8. The E-factor is now calculated and adjusted at the end of the year instead of the subsequent year per the previous study.

ii – As noted above, there were no changes to the calculation of overheads methodology from EB-2007-0681. No separate B&V report outlining this revised methodology was done. The updated process was documented in the above noted Section.

b) 2008 Actuals

HYDRO ONE DISTRIBUTION CALCULATION OF DISTRIBUTION OVERHEAD CAPITALIZATION RATE		
DISTRIBUTION CAPITAL		
Capital, inc. Cap OH		541.5
Less: Minor Fixed Assets		(56.2)
Less: Capitalized Overhead		(43.5)
Less: Capitalized Interest		(7.5)
Add: Capital contributions		46.9
Add: Removal costs		31.8
DISTRIBUTION CAPITAL		513.1
APPLICABLE Dx CCFS COSTS		
Dx CCFS Costs from Cost Distribution Model		129.3
Dx LBSS Facilities costs		20.0
Operating-Type Dx CCFS costs:		
Inergi-CSO in Dx CCFS		(37.9)
Inergi-ETS CSO Apps in Dx CCFS		(6.7)
Inergi-ETS Market Ready in Dx CCFS		(4.5)
Inergi-Settlements in Dx CCFS		(2.6)
		(51.7)
APPLICABLE Dx CCFS COSTS		97.7
Dx LABOUR CONTENT		
Labour in OM		246.7
Labour in Capital		200.2
		447.0
Dx LABOUR CONTENT		44.8%
Weighted Rate	50.0%	22.4%
Dx TOTAL SPENDING		
OM Spending		338.0
Capital Spending (excluding Overhead Capitalized)		513.1
		851.0
Dx TOTAL SPENDING		60.3%
Weighted Rate	50.0%	30.2%
Dx CCFS Cap=Capitalized Dx CCFS costs		
Weighted Average Rate		**52.5%**
Applicable CCFS Costs		97.7
Dx CCFS Cap=Capitalized Dx CCFS costs		**51.3**
Capitalized Asset Management Costs		
Non-operators		62.7
Non-operator costs to Dx Capital		9.0%
Capitalized Non-operators		5.6

HYDRO ONE DISTRIBUTION
CALCULATION OF DISTRIBUTION OVERHEAD CAPITALIZATION RATE

Operators	37.9	
Operator Costs to Dx Capital		3.0%
Capitalized Operators	1.1	
Customer Care	6.7	
Customer Care to Dx Capital		2.0%
Capitalized Customer Care	0.1	
Dx AM Cap = Capitalized Asset Management Costs	**6.9**	

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	51.3	10.0%
Dx AM Cap = Capitalized Asset Management Costs	6.9	1.3%
E-Factor	(14.4)	-2.8%
Total	**43.8**	**8.5%**
Capital	**513.1**	

2009 Q2 Forecast

HYDRO ONE DISTRIBUTION CALCULATION OF DISTRIBUTION OVERHEAD CAPITALIZATION RATE		
DISTRIBUTION CAPITAL		
Capital, inc. Cap OH		596.2
Less: Minor Fixed Assets		(41.4)
Less: Capitalized Overhead		(62.6)
Less: Capitalized Interest		(14.2)
Add: Capital contributions		43.3
Add: Removal costs		32.5
DISTRIBUTION CAPITAL		553.8
APPLICABLE Dx CCFS COSTS		
Dx CCFS Costs from Cost Distribution Model		142.6
Dx LBSS Facilities costs		21.0
Operating-Type Dx CCFS costs:		
Inergi-CSO in Dx CCFS		(37.8)
Inergi-ETS CSO Apps in Dx CCFS		(8.4)
Inergi-ETS Market Ready in Dx CCFS		(5.7)
Inergi-Settlements in Dx CCFS		(2.5)
		(54.4)
APPLICABLE Dx CCFS COSTS		109.2
Dx LABOUR CONTENT		
Labour in OM		277.7
Labour in Capital		154.4
		432.1
Dx LABOUR CONTENT		35.7%
Weighted Rate	50.0%	17.9%
Dx TOTAL SPENDING		
OM Spending		402.9
Capital Spending (excluding Overhead Capitalized)		553.8
		956.7
Dx TOTAL SPENDING		57.9%
Weighted Rate	50.0%	29.0%
Dx CCFS Cap=Capitalized Dx CCFS costs		
Weighted Average Rate		**46.8%**
Applicable CCFS Costs		109.2
Dx CCFS Cap=Capitalized Dx CCFS costs		**51.1**
Capitalized Asset Management Costs		
Non-operators		74.0
Non-operator costs to Dx Capital		9.0%
Capitalized Non-operators		6.7

HYDRO ONE DISTRIBUTION
CALCULATION OF DISTRIBUTION OVERHEAD CAPITALIZATION RATE

Operators	43.0	
Operator Costs to Dx Capital		3.0%
Capitalized Operators	1.3	
Customer Care	8.0	
Customer Care to Dx Capital		2.0%
Capitalized Customer Care	0.2	
Dx AM Cap = Capitalized Asset Management Costs	**8.1**	

E-Factor	
Amount capitalized for prior year (2007)	43.8
Amount that would have been capitalized for prior year (2007)	43.8
E-Factor	0.0

TOTAL OVERHEAD CAPITALIZATION RATE	**Total Capitalized**	**Capital-ization Rate**
Dx CCFS Cap=Capitalized Dx CCFS costs	51.1	9.2%
Dx AM Cap = Capitalized Asset Management Costs	8.1	1.5%
E-Factor	0.0	0.0%
Total	**59.2**	**10.7%**
Capital	**553.8**	

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #70 List 1

Interrogatory

Issue: #4.4

Reference: Exhibit C1/Tab 5/Schedule 3, Attachment 1, page 1

a) The B&V report states that "no common assets are allocated to Telecom and Remote Businesses, because these amounts would be very small". Please provide the order of magnitude involved.

Response

As part of our common asset allocations to Transmission and Distribution Hydro One conducted review of all our common assets to determine the allocation/attribution to all the Hydro One Business Units. It is recognized that some of the common assets, on occasion, could be used for Hydro One Telecom Inc. and/or Hydro One Remote Communities Inc. the frequency of usage was so negligible that it would not make business sense for us to build reporting mechanisms to track such usage. Consequently, it was decided that we would not attempt to track this usage nor provide an allocation percentage for Hydro One Telecom Inc. and Hydro One Remote Communities Inc.

Hydro One reviews this approach on an annual basis to ensure it is still appropriate.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #71 List 1

Interrogatory

Issue: #3.6 & #8.3

Reference: Exhibit C1/Tab 6/Schedule 1

a) With respect to page 2, Table 1, please explain why there are no Smart Meter Exclusion costs for 2006-2008, as in each of these years depreciation costs for that year (and in some cases earlier years) were tracked in a deferral account.

b) Please confirm that the Smart Meter Exclusions costs for 2009 and beyond are for Smart Meters installed after December 31, 2008. If not please explain. Also, please indicate if the "exclusion" includes any smart meter program costs besides those directly related to the meter installed (e.g., communication system costs, central data management costs, etc.).

c) Please confirm that the Depreciation and Amortization expense for 2010 and 2011 does not include any depreciation/amortization for conventional meters subject to replacement under the Smart Meter Program. If any such costs are included please explain.

Response

a) The 2006 to 2008 Distribution Depreciation expense shown in Table 1 of Exhibit C1, Tab 6, Schedule 1 reflects the actual depreciation expense, which includes the depreciation associated with Smart Meter, for Hydro One Distribution. As footnoted in Table 1 the depreciation associated with the Smart Meter spend is excluded from the Revenue Requirement calculation.

The Smart Meter depreciation expense included in Table 1 for 2006 is $0.1M, for 2007 is $2.2M and for 2008 is $4.6M.

b) Confirmed. Exclusions for smart meter costs in Table 1 of Exhibit C1, Tab 6, Schedule 1 pertain only to the depreciation of smart meter capital.

c) Hydro One Distribution confirms that it has included depreciation expense attributable to conventional meters in 2010 and 2011 in its submission. This is consistent with the previous recommendations of the Company's external depreciation Foster Associates (Ref: EB-2005-0378 Exhibit C1, Tab 7, Schedule 2, page 11) that assigned a 5 year straight-line amortization period to these meters.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #72 List 1

Interrogatory

Issue: #3.1

Reference: Exhibit C2/Tab 1/Schedule 1, page 1

a) Please clarify Footnote #1 by indicating the Smart Meter OM&A costs included and excluded from each year's reported OM&A. For example, does the 2008 value include the OM&A for smart meters installed in 2006 and 2007 but not that for the smart meters installed in 2008? Similarly, does the 2006 and 2007 OM&A exclude all Smart Meter OM&A?

Response

To clarify Note 1 in Exhibit C2, Tab 1, Schedule 1:

The OM&A expense of $399.3M in 2006, $486.4 in 2007 and $471.3M in 2008 excludes all Smart Meter related OM&A. The Smart Meter OM&A expense amounts excluded from OM&A are $4.9M in 2006, $6.2M in 2007 and $6.9M in 2008.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #73 List 1

Interrogatory

Issue: #4.1 and #8.3

Reference: Exhibit D1/Tab 1/Schedule 1, pages 2-3

a) Please clarify whether the In-Service Additions and Gross Asset Balance values reported in Table 2 included the capital cost for smart meter additions after December 31, 2008.

b) Please clarify whether the Accumulated Depreciation values reported in Table 1 include the depreciation for smart meter additions after December 31, 2008.

c) The footnote to Table 1 explains that the Smart Meter adjustment is meant to exclude from the Revenue Requirement the depreciation associated with Smart Meters that is currently tracked in a deferral account.
   - Is the reference to "currently" include the depreciation for smart meter additions in 2008?
   - Please explain more clearly how the $2.3 M for 2010 and 2011 was calculated and how the values relate to the Smart Meter Exclusions of $16.5 for 2010 and $24.2 M for 2011 discussed in Exhibit C1/Tab 6/Schedule 1, page 2.

d) Please confirm that the Distribution Rate Base set out in Tables 1 and 2 does not include any costs for conventional meters subject to replacement under the Smart Meter Program. If any such costs are included please explain.

Response

a) The test year values in Table 2 for In-Service Additions and Gross Asset Balance figures do not include capital costs for smart meter additions after December 31, 2008.

b) Accumulated Depreciation test year values in Table 1 do not include the depreciation for smart meter additions after December 31, 2008.

c) Please be advised that the original note filed in the evidence under Table 1 within Exhibit D1, Tab 1, Schedule 1, page 2, is incorrect. The note should have been the following: "a) This adjustment is to exclude from Revenue Requirement the working capital associated with Smart Meters that is currently tracked in a deferral account."

Smart Meter additions in 2008 are included in rate base. Smart Meter additions in 2009 and onward are tracked in the deferral account.

$2.3M is the working capital exclusion related to Smart Meter OM&A in 2010 and 2011 test years. The figure is calculated by taking the planned 2010 and 2011 spend of $15.4M per year multiplied by 15% as the estimated working capital ratio. As this amount is included in the calculation of Smart Meter revenues in the deferral account, it is excluded from the calculation of Hydro One distribution rate base. The $2.3M amounts are not related to the $16.5M and $24.2M. The $16.5M and $24.2M amounts for 2010 and 2011 respectively in Exhibit C1, Tab 6, Schedule 1 are the depreciation amounts related to the 2010 and 2011 Smart Meter additions.

d) Please refer to Exhibit H, Tab 7, Schedule 72, part c).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #74 List 1

Interrogatory

Issue: #9.2

Reference: Exhibit D1/Tab 1/Schedule 3

a) Are the Development capital additions shown in Table 1 net of the external funding to be provided by the GAM? What is the external (GAM) funding associated with the capital additions for 2010 and 2011?

b) The text on page 3 suggests that capital additions are increasing in 2010 and 2011 relative to historic years due to a higher level of New Connections and Upgrades activity. However, Exhibit D1/Tab 3/Schedule 3, page 5 (lines 12-15) states that the level of customer contributions is expected to remain at historic levels (prior to Update and adjustment for proposed DSC changes). Please reconcile.

Response

a) Yes, the Development capital additions shown in Table 1 are net of the external funding. The external (GAM) funding associated with the capital additions for 2010 and 2011 are summarized in the table on page 1 of Exhibit A, Tab 14, Schedule 2 and in the footnote to Table 1 of Exhibit D1, Tab 3, Schedule 3.

b) Capital additions are increasing due to increases in Transport, Work and Service Equipment, the increase in the number of new connections and the replacement of existing plant to meet Regulation 22/04 that cannot be recovered from new customers. Customer contributions are dependent on the mix of "lies along" customers who are given a basic connection at no cost versus expansion customers who may contribute a capital contribution based on a DCF calculation. In addition for expansion customers, residential customers contribute more than general service customers whose loads generally provide greater financial support.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #75 List 1

Interrogatory

Issue: #4.5

Reference: Exhibit D1/Tab 1/Schedule 4, page 3

a) Please provide a schedule setting out the calculation of Cost of Power values for 2010 ($2,008.4 M) and for 2011 ($1,994.6 M). In doing so please provide the rates and volumes assumed for each cost of power component.

b) Are any of Hydro One Networks' customers (i.e., Retail customers or Embedded LDCs & Directs) registered as "Market Participants" with the IESO? If yes, what percentage of total forecast load for 2010 and 2011 do these customers represent and has this been taken into account in the Cost of Power calculations?

Response

a) Refer to Exhibit H, Tab 3, Schedule 23, part a).

b) Yes, a portion of Hydro One Networks' customers are registered as Market Participants. Market Participants make up approximately 35% of total forecasted load for both 2010 and 2011. Market Participants are not included in the cost of power calculation.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #76 List 1

Interrogatory

Issue: #4.6

Reference: Exhibit D1/Tab 2/Schedule 1

a) With respect to Section 4.2 (pages 19-26), please comment on the change in asset condition for each of the P2 categories from that documented for purposes of EB-2007-0681.

Response

For most P2 assets, conditions have not changed appreciably from those that existed at the time of our 2008 Distribution Application (EB-2007-0681). The two exceptions are PCBs (Stations and Lines) that were moved to a P2 from a P3 in EB-2007-0681, and Submarine Cable.

As discussed on pages 22 and 23 of Exhibit D1, Tab 2, Schedule 1, the significant change with PCB equipment is that new legislative requirements were passed into law in September 2008. Prior to that date, Hydro One Distribution had suspended PCB expenditures pending the new legislative requirements. As a result, the amounts of PCB remaining in-service have not been reduced appreciably since EB-2007-0681. Given that the new PCB legislative has fundamentally altered the interpretation of PCB conditions, Hydro One Distribution is proposing increases in expenditures to retire PCB equipment and address the unacceptable presence of PCBs on the distribution system.

The second exception is submarine cables. Since EB-2007-0681, visual inspections and cable failures have continued to signal the deterioration of the submarine cable population due to corrosion. The level of deterioration has been significant and given that corroded cables pose significant safety risks to the public, Hydro One Distribution has implemented a new cable testing program as discussed at the bottom of page 18 of Exhibit C1, Tab 2, Schedule 2, and on page 24 of Exhibit D1, Tab 2, Schedule 1.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #77 List 1

Interrogatory

Issue: #4.1

Reference: Exhibit D1/Tab 3/Schedule 1

a) Please provide a schedule setting out the 2008 Board approved capital spending consistent with Table 1 (page 2).

Response

Description	Historic			Bridge		Test		
	2006	Board approved 2006	2007	2008	Board approved 2008	2009	2010	2011
Sustaining	172.2	119.6	146.9	170.7	152.3	176.5	185.8	202.5
Development	146.8	137.2	154.2	153.2	167.7	167.9	205.7	252.4
Operations	2.1	3.5	2.0	0.9	3.6	2.4	8.1	11.2
Shared Services & Other Capital	57.4	72.7	96.8	110.6	77.8	103.5	164.8	110.8
TOTAL	**378.5**	**333.0**	**399.9**	**435.3**	**401.4**	**450.5**	**564.4**	**576.9**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #78 List 1

Interrogatory

Issue: #4.2

Reference: Exhibit D1/Tab 3/Schedule 2, page 3

a) Please explain the increase in 2008 capital spending (over the Board approved values) for Stations and Lines.

Response

Stations:

Actual expenditures were $12.5 million compared to a Board approved amount of $10.3 million. The difference of $2.2 million is predominantly attributed to the need for additional investment in component replacement to address conditions found during routine maintenance and inspections. The largest single component of this was expenditures on both planned and emergency station grounds and fences. These particular investments were influenced by copper theft and the need to both secure stations and replace stolen grounds.

Lines:

Actual expenditures were $157.2 million compared to a Board approved amount of $139.5 million. The difference of $17.7 million is attributed to:

- An $8.6 million increase in Trouble Call and Storm Damage costs (i.e. $62 million actual costs compared to a Board approved level of $53.4 million). The difference is due to increased storm activity in 2008 and in particular a significant storm restoration effort during the last week of 2008 following a severe winter storm.

- A $7.5 million increase in Joint Use and Line Relocations (i.e. $31.2 million actual costs compared to a Board approved level of $23.7 million) due to increased activity by joint use partners and road authorities above the level of demand anticipated.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #79 List 1

Interrogatory

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 2, pages 6-8
ii) Exhibit D2/Tab 2/Schedule 3 – ISD #S1
iii) EB-2007-0681, D2/T2/S1, IJD #S1

a) According to Reference (iii) the capital spending proposed in EB-2007-0681 for 2008 was to address the current gap in the number of spare transformers. However, Reference (ii) suggests that the gap still exists and, indeed, includes the purchase of more transformers than the 2008 Rate Application. Please reconcile.

Response

The 2008 spare transformer purchase did result in an increase of the compliment of spare transformers. Recent analysis has revealed that a gap still exists between the existing compliment and the number of spares required as a result of factors such as transformer failures, immediate end-of-life replacements, and PCB requirements. The 2010 and 2011 funding will address the current spare transformer inventory requirements.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #80 List 1

Interrogatory

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 2, pages 10-13
ii) Exhibit D2/Tab 2/Schedule 3 – ISD #S3 & #S4
iii) EB-2007-0681, D2/T2/S1, IJD #S3 & #S4

a) Please confirm that there was no allowance for Spill Containment projects (Reference (i), page 11) in the EB-2007-0681 Application. If there was, what was the proposed 2008 capital spending?

b) With respect to Station Refurbishment projects, please explain why the Iroquois Dam DS is one of the projects in the current Application (Reference (ii), S#4) when it was also included in the 2008 Rate Application (Reference (iii), S#3).

c) Please explain the increase in Station Refurbishment costs from 2008 approved ($2.5 M) to $3.2 M in 2010 and $3.4 M in 2011, particularly when the number of stations being refurbished in each year (per Reference (ii), S#4) appears to be less than the number that were included for 2008 in Reference (iii), S#3.

d) Please explain why the 2010 and 2011 spending on Component Replacement and Demand is higher (i.e,, $3.8 M and $4.0 M) than that proposed and approved for 2008 - $2.6 M.

Response

a) In EB-2007-0681, $0.3 million was allowed for under Station Refurbishment Projects and $0.1 million was spent.

b) Iroquois Dam DS was not completed in 2008 due to land ownership issues. The project was halted pending a review of site ownership. The current plan is to complete the project over the 2010 and 2011 period.

c) The costs associated with individual station refurbishment projects vary significantly according to project size, specifications, location, station voltage and complexity of work to be done. Given the relatively low number of station refurbishment projects completed in a given year (i.e. less than 10), there can be significant year-to-year variability for the total program costs. The proposed test year spending reflects the costs for the specific station refurbishment work planned in those years.

d) The increase of $1.2 million over the 2008 Board approved spending level is attributed to:

- $0.4 million associated with an increasing need to address deteriorated components such as surge arrestors, fences and switches that have reached end-of-life as identified through inspections and routine maintenance.

- $0.6 million associated with the replacement of obsolete reclosers as detailed in ISD S6 in Exhibit D2, Tab 2, Schedule 3.

The remainder of the increase is associated with expected escalation.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #81 List 1

Interrogatory

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 2, pages 20-22
ii) EB-2007-0681, D1/T3/S2, page 20

a) The 2008 Application projected 7,000 pole replacements at a cost of $39.8 M. Actual replacements were 6,736 at a cost of $43.0 M. Please explain the variance and whether the higher unit cost is carried forward in the projections for 2010 and 2011.

b) How many of the pole replacements planned for 2011 are attributable directly to the red pine pole problem?

Response

a) Actual unit costs for pole replacements can vary based on a variety of factors including pole heights and classes, ground conditions and pole settings, the number of circuits supported, and location (e.g. rural vs. urban). As the precise mixture of these factors varies from one year to the next, so does the actual unit cost. In 2008, the actual unit cost was $6,385 due to a more time consuming and challenging mixture of poles being replaced. The 2008 unit cost was not carried forward into 2010 and 2011 as evidenced in the estimated unit costs (i.e. $6,023 for 2010 and $6,264 for 2011).

b) 2,000 poles.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #82 List 1

Interrogatory

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 3, page 5

a) Please confirm that the Customer Connections referred to in Section 2.1.1 are load customer connections. If not, please discuss the relationship between this Section and Section 2.2.

b) Please reconcile the increase in customer connection costs (2010 vs. 2008) when the number of connections in 2010 is actually forecast to be less than in 2008.

c) Please confirm that the impact of the DSC changes (per lines 14-18) is to reduce the estimated capital contributions by $2 M per annum. If not correct, please provide the impact.

d) Please discuss what types of investment activities Hydro One Networks considers to be "enhancements" as opposed to "expansion" for the purpose of applying the cost recovery provisions of the DSC, particularly with respect to load and non-renewable energy generation customers.

Response

a) Yes, this is confirmed.

b) The factors contributing to the increase in connection costs are detailed in the response at Exhibit H, Tab 1, Schedule 84, most of which also contribute to the increase relative to 2008.

c) Yes, this is confirmed.

d) Hydro One will use the same definitions for expansion and renewable enabling improvements for non-renewable generation customers as those that have been proposed for renewable generation customers in the DSC.

Hydro One considers the following work as an "expansion" of the distribution system when connecting load customers:

1) building a new line,
2) upgrading an existing single phase line to three phase to connect a three phase customer, and

3) bringing in a higher voltage line to supply loads above 500 kW.

Hydro One considers the following work as an "enhancement" of the distribution system when connecting load customers:

1) increasing the size of the distribution station transformer,
2) reconductoring an existing line,
3) modifications to, or the addition of voltage regulating equipment,
4) increasing the size of the breakers or reclosures, and
5) modifications that improve system operating characteristics such as the ability to change supply configurations.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #83

Interrogatory

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 3, pages 7-10
ii) Exhibit D2/Tab 2/Schedule 3

a) With respect to ISD #D3, when is the feeder expected to reach "overloading" conditions?

b) Why are none of the costs of the new transformers required in ISD #D7 recoverable from the new customer?

c) Why are none of the costs for ISD #D8, D13, and D16 recoverable from the new customers?

d) Why is none of the costs of ISD #D15 recoverable from Orillia Power Corporation or the cost of ISD #D24 recoverable from Wasaga Distribution or the cost of ISD #26 recoverable from the Midland or Newmarket LDCs?

e) Many of the ISD descriptions make reference to ongoing load growth (D3, D4, D5, D6, D7, D10, D11, D12, D13, D15, D16, D17, D18, D19, D20, D21, D24, D25, and D26). At the same time, Hydro One Networks is forecasting a steady decline in total distribution load from 2006 to 2011. Please reconcile and, in doing so, indicate those areas of Hydro One Networks' service area where load is forecast to decline sufficiently to produce a net year over year reduction in total distribution load.

Response

a) The feeder is expected to reach its design loading limit during the summer of 2012.

b) The investment is being made to reinforce the existing system and provide for future load growth.

c) These investments are being made to reinforce the existing system and provide for future load growth.

d) Under the Distribution System Code (DSC), a distributor shall continue to plan and build the distribution system for reasonable forecast load growth. Reasonable forecast load growth is not easily defined when it pertains to an embedded distributor, and in situations where a feeder supplies more than one embedded distributor this becomes even more difficult. In considering the various scenarios it was decided that costs to support normal load growth when supplying an embedded distributor should be pooled. This follows the same rationale that pools the costs for an individual customer's normal load growth. On this basis, the costs of these investments are included in the sub-transmission rate pool.

e) As shown in Table 4, page 19 of Exhibit A, Tab 14, Schedule 4, total distribution load has been declining since 2006. Selected stations and feeders however, are still experiencing growth in the number of new customer connections. The Investment Summary Documents noted in the above question indicate the specific stations and feeders that are experiencing growth and/or requiring new investment. Due to the economic climate that Ontario is presently in and the impact of Hydro One's CDM programs the total distribution load is declining. The load reduction is generally occurring across all service areas.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #84 List 1

Interrogatory

Issue: #4.2 and #9.3

Reference: Exhibit D1/Tab 3/Schedule 3, pages 12-14

a) The discussion does not distinguish between the treatment of renewable energy generation projects and non-renewable energy generation projects.
   - Please indicate any differences that exist in the cost responsibility treatment of the two types of projects.
   - Is Hydro One Networks assuming that all new generators will be renewable energy generation facilities?

b) The text on page 12 (lines 8-11) describes connection assets as assets that lie between the point of connection on the distribution system and the facilities on the customer's property. The text on page 12 (lines 22-28) suggests that "connection" spending could i) include the replacement of existing assets and ii) be of benefit to other customers.
   - Please reconcile this classification of "replacement" costs as connection costs with the OEB's September 11, 2009 DSC (section 3.2.30) amendments which classify such costs as "expansion".
   - Please explain how connections could involve replacement of existing assets when (by Hydro One Networks' own definition) connections start at the point of connection to the distribution system.

c) Please clarify whether the Total Capital costs in Table 4 are just the cost for "connections" as defined on page 12 or whether they also include the costs for "expansion" and "enabling improvements" as defined on the same page.

d) How does Hydro One Networks distinguish between the enhancement spending reported in Table 4 and that reported in Table 5?

Response

a) Hydro One follows the requirements of the DSC which will specify different cost treatment for renewable vs non-renewable generators once the proposed amendments to the DSC are approved. Among other things, the $90K/MW expansion cost cap will only apply to renewable generators. Non-renewable generators will pay contributions as per the current DSC requirements. Hydro One expects that the vast majority of generation connection applications will be for renewable energy generators, particularly until such time as the Clean Energy Standard Offer Program is launched.

b) The referenced paragraph (page 12, lines 22-28) describes the historical treatment of connection assets and further the term "connection" used in that paragraph refers to all three categories of facilities as defined in the proposed DSC amendments (i.e. i) Connection Assets, ii) Expansion, iii) Renewable Enabling Improvements). Expansion and Renewable Enabling Improvement investments could involve the replacement of existing assets.

c) The Total Capital costs in Table 4 include the costs for "connection assets", "expansion" and "Renewable enabling improvements" ("REI").

d) Spending in Table 4 is demand driven work to connect generators, where as spending in Table 5 is related to investments that commence in 2010 to enable government objectives, as defined in the Green Energy and Green Economy Act, to shorten connection process times by building the necessary infrastructure for anticipated future renewable generation connections.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #85 List 1

Interrogatory

Issue: #9.3

Reference: Exhibit D1/Tab 3/Schedule 3, page 16

a) Please explain how the ratepayer funded portion was determined for the first two categories in Table 5.

Response

Hydro One's criteria for determining the ratepayer funded portion of Expansion investments is outlined in Exhibit A, Tab 14, Schedule 2, page 16 to 19. The total benefit to Hydro One Distribution customers from Expansion projects was estimated at 18% of the investment, which means that approximately 82% of Expansion investments is proposed to be funded by all electricity consumers in the province. The first category in Table 5, "Targeted Enhancements to Support Distributed Generation", is considered an Expansion activity and therefore, the above allocation methodology was applied:

$ Millions	Total Capital Costs		Externally Funded Costs		Net Capital Costs	
	2010	2011	2010	2011	2010	2011
Targeted Enhancements to Support Distributed Generation	31.6	87.0	(31.6 * 82%) 25.9	(87 * 82%) 71.2	5.8	15.8

Hydro One's criteria for determining the ratepayer funded portion of investments for Renewable Enabling Improvments (REI) is outlined in Exhibit A, Tab 14, Schedule 2, page 20 to 23. The second category in Table 5, "Station Upgrades for Protection, Control, & Load Rejection", is an REI investment that contains three separate REI components. The table below summarizes how the portion of this investment to be funded by all electricity consumers in the province was determined.

	Gross Cost ($M)		Portion allocated to Global Adjustment	Costs Externally Funded	
	2010	2011		2010	2011
Load Rejection at Distribution Stations	2.2	5.1	100%	2.2	5.1
Protection Modification for DS with Downstream Generation	0.8	1.0	100%	0.8	1.0
SCADA for Distribution Stations	18.2	30.7	91%	16.5	27.9
Total	21.1	36.8		19.5	34.1

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #86 List 1

Interrogatory

Issue: #4.2 and #9.2

Reference: Exhibit D1/Tab 3/Schedule 3

a) Please provide a schedule that maps the Generation Connection Program and Generation Connection Enhancement costs set out in Tables 4 & 5 into the cost categories used in Hydro One Networks' Green Energy Plan (i.e., Connection Assets, Expansion and Renewable Enabling Improvements) and reconcile the totals (both gross and net).

Response

Generation Connection Program Costs by DSC Cost category

$ Millions		Total Capital Costs		Generator Funded Costs		Externally Funded Costs		Net Capital Costs	
		2010	2011	2010	2011	2010	2011	2010	2011
Mid-size Generation connections	Connection Assets	12.7	26.1	12.7	26.1	0.0	0.0	0.0	0.0
	Expansion	21.1	37.4	0.0	0.0	18.1	31.5	2.9	5.9
	REI	49.5	82.1	0.0	0.0	47.0	76.7	2.5	5.4
	sub-TOTAL	83.2	145.6	12.7	26.1	65.1	108.2	5.4	11.3
Upgrades and Transfers	Connection Assets	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Expansion	17.8	16.7	0.0	0.0	14.6	13.6	3.2	3.0
	REI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	sub-TOTAL	17.8	16.7	0.0	0.0	14.6	13.7	3.2	3.0
Other Generation Connections Work	Connection Assets	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0
	Expansion	1.9	1.8	0.0	0.0	1.5	1.5	0.3	0.3
	REI	2.5	2.4	0.0	0.0	2.4	2.2	0.1	0.2
	sub-TOTAL	5.1	4.8	0.7	0.7	3.9	3.6	0.5	0.5
Total		**106.0**	**167.1**	**13.3**	**26.8**	**83.6**	**125.5**	**9.1**	**14.8**

Generation Connection Enhancements Program Costs by DSC Cost Category

$ Millions		Total Capital Costs		Externally Funded Costs		Net Capital Costs	
		2010	2011	2010	2011	2010	2011
Targeted Enhancements to Support Distributed Generation	Connection Assets	0.0	0.0	0.0	0.0	0.0	0.0
	Expansion	31.6	87.0	25.9	71.2	5.8	15.8
	REI	0.0	0.0	0.0	0.0	0.0	0.0
	sub-TOTAL	31.6	87.0	25.9	71.2	5.8	15.8
Station Upgrades for Protection, Control, & Load Rejection	Connection Assets	0.0	0.0	0.0	0.0	0.0	0.0
	Expansion	0.0	0.0	0.0	0.0	0.0	0.0
	REI	21.1	36.7	19.5	34.1	1.6	2.7
	sub-TOTAL	21.1	36.8	19.5	34.1	1.6	2.7
Feeder Control Infrastructure	Connection Assets	0.0	0.0	0.0	0.0	0.0	0.0
	Expansion	0.0	0.0	0.0	0.0	0.0	0.0
	REI	5.8	4.0	5.8	4.0	0.0	0.0
	sub-TOTAL	5.8	4.0	5.8	4.0	0.0	0.0
Wholesale Revenue Metering Modifications	Connection Assets	0.0	0.0	0.0	0.0	0.0	0.0
	Expansion	0.0	0.0	0.0	0.0	0.0	0.0
	REI	1.7	1.2	1.7	1.2	0.0	0.0
	sub-TOTAL	1.7	1.2	1.7	1.2	0.0	0.0
Wireless Telecommunications Stop-Gap	Connection Assets	0.0	0.0	0.0	0.0	0.0	0.0
	Expansion	0.0	0.0	0.0	0.0	0.0	0.0
	REI	2.1	0.0	2.1	0.0	0.0	0.0
	sub-TOTAL	2.1	0.0	2.1	0.0	0.0	0.0
TOTAL		**62.4**	**129.1**	**55.0**	**110.5**	**7.4**	**18.6**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #87 List 1

Interrogatory

Issue: #4.2 and #9.2

Reference: i) Exhibit D1/Tab 3/Schedule 4
ii) EB-2007-0681, D1/T3/S4, page 2

a) Please explain why the level of Operations Capital spending in both 2008 and 2009 (per Reference (i), Table 1) was less that the Board Approved 2008 level of $3.6 M.

b) Please provide a schedule that sets out how much of the Operations Capital spending in 2010 and 2011 is related to i) renewable energy generation (per Reference (i), page 2, lines 12-20) and ii) smart meters (per Reference (i), page 2, lines 22-28).

c) Why isn't any of the Operations Capital Spending attributable to distributed generation included in the Renewable Generation portion of the Green Energy Plan?

Response

a) Four factors contributed to the lower than plan capital spending:

- The anticipated capital work associated with integration of Smart Meter Data into the Outage Management System ($0.5M in 2008) was delayed as dependant technology specifications have not yet been finalized.
- Enhancements to ORMS archiving functionality eliminated the need for the anticipated investment in a historical data management ($1.3M in 2008, $0.4M in 2009).
- Cost associated with Facilities Sustainment/Refresh elements are lower due to delays in procurement.
- The investment in Real Time Feeder Analysis was deferred ($0.2M in 2008 and $1.8M in 2009) as this work will be completed in conjunction with the proposed Distribution Management System.

b) The following schedule sets out how much of the Operations Capital spending in 2010 and 2011 is related to renewable energy generation and Smart Meters.

YEAR		**2010**	**2011**
Investments related to renewable energy generation	M$	4.9	8.6
Incorporate Smart Meters Into ORMS	M$	1.8	1.2
TOTAL		**6.7**	**9.8**

c) The Operations Capital spending associated with distributed generation is included in the Smart Grid portion of the Green Energy Plan, Exhibit A, Tab 14, Schedule 2, pages 29-30.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #88 List 1

Interrogatory

Issue: #4.3

Reference: i) Exhibit D1/Tab 3/Schedule 8, pages 3-4
ii) Exhibit D2/Tab 2/Schedule 3, IED #C1

a) Please provide a schedule that breaks down the projected spending on Field Facilities Requirements between i) spending on new facilities and additions to accommodate staff increases and ii) replacement/renovation of existing facilities.

b) Please indicate the top 5 field locations experiencing staff increases that give rise to the need for new facilities and explain the reasons for the staff increases in each.

c) What has "changed" in the last year that gives rise to the material increase in spending requirements to maintain existing facilities in Field Facilities?

Response

a)

Description	Historic			Bridge	Test	
	2006	2007	2008	2009	2010	2011
Field Facilities Total $ Million	$3.4	$6.9	$5.8	$21.4	$18.9	$17.9

The major investments decisions in the field facilities are not driven exclusively by growth or replacement of existing facilities alone. They are made based on facilities assessment that considers a number of factors including facilities that are near the end of their life, inadequate for changing business needs (this includes providing accommodation for additional staff) or which historically were experiencing operating deficiencies including health and safety issues. In addition to these criteria the requirements of business units are examined for short and long term needs and acceptable accommodation alternatives available in the local real estate markets. Based on these considerations decisions are made to build new facilities, conduct major renovations including building additions to existing promises or consider limited lease options. In addition structural and other building improvements are conducted on priority bases to existing facilities as result of asset condition assessments. The level of the capital facilities sustainment spending varies from year to year and depends on business circumstances.

Hydro One currently estimates minimum of $5M in 2010 and $5M in 2011 in additional investments required to accommodate staff in the field (considering on high level assumptions temporary leased modular buildings accommodations) as result of anticipated increase in the work activities mainly due to Green Energy Act.

As result of anticipated work program increases space assessments will be conducted with respective business units to establish more accurate work space needs in response to the Green Energy Act, modernization of distribution systems and connecting distribution generation work initiatives as more information will become available.

b) The Company experiences work program growth across the Province which affects all field facilities. The investments decisions in the field facilities are not driven exclusively by growth or replacement of existing facilities (existing locations) alone but rather are made based on facilities assessment that considers number factors. During investment decisions some of the main factors taken into consideration include: existing facilities conditions including facilities that are near the end of their life and/or which historically were experiencing operating deficiencies including health and safety issues, facilities that are inadequate for changing and increasing business needs (this includes providing accommodation for additional staff and/or work equipment). Ultimately the accommodation needs of lines of business are examined in terms of short and long term needs, logistics and geographic proximity to service areas, work sites and corresponding acceptable accommodation alternatives available in the local real estate markets.

c) The capital investment is required for field facilities in order to continue to provide adequate workspace accommodation for various types of staff resources (e.g. regular, temporary) and accommodate lines of business operating requirements. The investment need is driven by the following key factors:

- aging facilities asset base that are near the end of their life;
- emerging accommodation needs from the development and growth of Company new work programs / initiatives, (e.g. Distributed Generation, Green Energy Act); and
- lines of business expanding work programs and changing business requirements.

Please also refer to response at Exhibit H, Tab 1 Schedule 96.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #89 List 1

Interrogatory

Issue: #4.3

Reference: i) Exhibit D1/Tab 3/Schedule 8, pages 4-5

a) What is the current Head Office space currently leased (square footage) and how many staff positions did it accommodate as of December 31, 2008? Note – Please include positions that are vacant but for which there is "space" provision.

b) Please provide an organization chart outlining those business areas accommodated at the Head Office Facility and the number of staff in each (including approved vacant positions) as of December 31, 2008.

c) Please provide an organization chart outlining the business areas that will be accommodated at the newly leased Head Office Facility and indicate the number of staff in each, including the planned growth of 500 staff.

Response

a) Hydro One experienced continued growth in work space demand driven by increased workloads and new programs and initiatives.

In 2005 Hydro One exercised lease renewal option and entered into five year lease agreement with current landlord at 483 Bay Street for a total rentable area of approximately 190,000 sq. feet. In 2007 a decision was made to relocate Inergi LP staff from Hydro One head office location in order to accommodate at that point in time Hydro One head office workspace requirements. As result, Hydro One secured additional leased office space of approximately 40,000 sq. feet at Atrium on Bay location (20 Dundas West) to accommodate relocation of Inergi Staff. In the subsequent year Hydro One continued to experience work program expansion, and in 2008 approximately 60,000 sq. feet of additional office space was subleased at 483 Bay Street as result of the staff growth.

As of December 31, 2008 the total consolidated head office space consisted of 290,000 sq. feet, which included approximately 190,000 sq. feet that corresponds to current lease agreement that will expire in January 2010 and approximately 100,000 sq. feet of additional office space (including Inergi) that was secured during the time period prior to December 31, 2008 to meet Company accommodations requirements. These workspace requirements include space accommodation for various types of staff resources e.g. regular, temporary, contractors and consultants. The total number

of workstations accommodated at 483 Bay Street as of December 2008 was approximately 1580.

A new eleven year lease term at 483 Bay Street commencing February 1, 2010 will compromise of approximately 285,000 sq. feet and will replace the total current leased and recently subleased space at 483 Bay Street of 190,000 sq. feet and 60,000 sq. feet respectively. (The Inergi LP workspace requirements are not included in a new head office lease at 483 Bay Street and will continue to be accommodated at 20 Dundas Street West).

b) The table below outlines respective business units that were accommodated at 483 Bay Street and their respective share of head office work space as of December 31, 2008. (There were no space vacancies as of December 31, 2008)

Business Unit	Total work space by Line of Business (in thousand sq. feet)	Total work space by Line of Business by (%)
Asset Management	59	24%
Corporate Functions & Services	62	25%
Customer Operations	9	3%
Grid Operations	11	5%
Engineering & Construction Services	109	43%
Total:	250	100%

c) The table below outlines the approximate planned share of head office work space by business areas that will be accommodated at the newly leased head office facility at 483 Bay Street commencing as of February 1, 2010. The staff workspace requirements include space accommodation for various types of staff resources e.g. regular, temporary, contractors and consultants. The newly leased head office space at 483 Bay Street will provide accommodation to approximately 1,700 staff. (This represents an increase in workspace accommodation for approximately 500 staff from the point when Hydro One assumed total rentable area of 190,000 sq. at 483 Bay Street by relocating Inergi staff in 2007.)

This does not include Company accommodation requirements as result of Green Energy Act, modernization of distribution systems and connecting distribution generation work initiatives.

Business Unit	Total work space by Line of Business (in thousand sq. feet)	Total work space by Line of Business by (%)
Asset Management	54	19%
Corporate Functions & Services	69	24%
Customer Operations	14	5%
Grid Operations	15	5%
Engineering & Construction Services	133	47%
Total:	285	100%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #90 List 1

Interrogatory

Issue: #4.3

Reference: Exhibit D1/Tab 3/Schedule 8, page 6

a) Why is there no capital spending on security infrastructure prior to 2010?

Response

Please refer to Exhibit H, Tab 1, Schedule 97.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #91 List 1

Interrogatory

Issue: #4.3 and #9.2

Reference: Exhibit D1/Tab 3/Schedule 9, page 5

a) Please document how the $83 M capital spending on TWE attributed to the GEGEA was determined. Why is none of this included in the Green Energy Plan?

Response

The Green Energy Plan outlined in Exhibit A, Tab 14, Schedule 2 provides a high-level overview of the major 'green' programs and initiatives that Hydro One will be undertaking. The A-14-2 exhibit is only intended to summarize the program and project investments required because of the Green Energy Act. The exhibit consolidates information found in the exhibits addressing the broad areas of Sustainment, Development, Operations and Shared Services OM&A and Capital.

The planned capital expenditures for T&WE Services for supporting the overall capital and OMA work programs including the initiatives outlined in the Green Energy Plan are reflected in Exhibit D1, Tab 3, Schedule 9 for both 2010 and 2011.

The $83 million is an estimate of the equipment requirements based on the expected levels of staff and equipment utilization required to fulfill the demands of the growing Transmission and Distribution capital and OM&A work programs, including the expected increased activities from the initiatives of the Green Energy Act in 2010 and 2011. The breakout of the GEA amounts for T&WE are in the table below.

Type of Equipment	GEA Capital Allocation (M$)	Additional # of Units Required
Light Transport	$ 7.6	213
Work Equipment	$ 75.4	394
Total	**$ 83.0**	**607**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #92 List 1

Interrogatory

Issue: #4.5

Reference: Exhibit D2/Tab 4/Schedule 1

a) Please explain why the "smart meter adjustment" was included in the determination of working capital.

Response

a) The $2.3M smart meter adjustment is the working capital exclusion related to Smart Meter OM&A in 2010 and 2011 test years. The figure is calculated by taking the planned 2010 and 2011 spend of $15.4M per year multiplied by 15% as the estimated working capital ratio. As this amount is included in the calculation of Smart Meter revenues in the deferral account, it is excluded from the calculation of Hydro One distribution rate base.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #93 List 1

Interrogatory

Issue: #1.1 and #1.5

Reference: Exhibit E1/Tab 1/Schedule 1, Attachment 1
OEB Filing Requirements for Transmission and Distribution Applications, May 2009, page 18

a) Please revise the schedule so that it sets out 2010 and 2011 distribution revenues at current (2009) rates and the revenue sufficiency/deficiency for each year excluding rate riders.

Response

a) Please see the revised schedule below that sets out 2010 and 2011 distribution revenues at 2009 rates, excluding rate riders.

Particulars	2010	2011	
Rates Revenue Requirement (excl. riders)	1,101.4	1,215.5	a
Revenue at 2009 rates (excl. riders)	981.8	981.1	b
Revenue deficiency/(sufficiency)	119.6	234.4	c = a - b

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #94 List 1

Interrogatory

Issue: #2.2

Reference: Exhibit E1/Tab 1/Schedule 2

a) With the increased distributed generation (arising from the GEGEA) does Hydro One Networks expect to receive revenues from Standby Charges (pages 6-7) in 2010 and 2011? If not, why not.

b) Would external revenues from New Connections and Upgrades include work done for new generator customer connections? If not, why not and where is such revenue captured? If yes, why is there no additional revenue shown for 2010 and 2011 given the projected increase in new generator connections?

c) For what portion of the new generator connections projected for 2010 and 2011 (D1/T3/S3, page 11) will generation studies be completed by year end 2009?

d) With respect to the projected volume of Generation Studies for 2010 and 2011, the Green Energy Plan indicates (A/T14/S2, page 7) the recent changes introduced by the GEGEA and the OPA will lead to increased interest in renewable distributed generation. Based on this, why isn't the number of requests for generation studies forecast to increase during the test period (page 10)?

Response

a) Hydro One Networks does not expect to receive revenues from Standby Charges due the increased number of distributed generators (DG) as a result of the GEGEA. It is expected that almost all DG in Hydro One Networks' planning horizon will be a result of the OPA's FIT program. DG with a generating capacity greater than 10 kW will be included in Hydro One Networks' DGen rate class and do not attract Standby Charges. Standby Charges do not apply to generators with a capacity equal to or less than 10 kW. The application of Standby Charges to an associated load account would not be appropriate given that the recent OEB decision EB-2009-0303 requires that settlement and billing in relation to a renewable generation facility that has a FIT contract and the associated load customer should be based on a "gross load billing" approach.

b) External Revenues for New Connections and Upgrades does not include work done for generator connections. The external revenues associated with line work for others is discussed in Section 3.2.4 of Exhibit E1, Tab 1, Schedule 2. In accordance with the

proposed Distribution System Code amendments issued by the Board on September 11, 2009, the work that was previously captured under external revenues was re-classified as Expansion investments, and included as part of the Development capital investments that contribute to Hydro One Distribution's Green Energy Plan.

c) Since the FIT Program launch period is Oct 1 through Nov 30 in 2009, and the Commercial Operation Date is the test for shovel-readiness which will determine the priority of each project that applies for FIT with respect to getting capacity allocated, Hydro One cannot determine what portion of generation studies will be completed by year end 2009.

d) Hydro One had based its forecast for the number of requests for generation studies based on historical numbers. As well, at the time that Hydro One submitted its distribution rate filing, the FIT rules had not been finalized, so Hydro One was unaware of the FIT rule that required existing CIAs to be rescinded. Therefore, Hydro One expected the historical number of requests for generation studies to continue.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #95 List 1

Interrogatory

Issue: #1.1 and #6.1

Reference: Exhibit F1/Tab 1/Schedule 1, pages 2-6
OEB Filing Requirements for Transmission and Distribution Applications, May 2009, Section 2.10.1

a) For each of the accounts listed in Table 2, please provide a continuity schedule for the period January 1, 2005 to present showing the opening balance, annual adjustments, accruals, interest and closing balance for each year.

b) For the RSVA accounts please provide a continuity schedule (per part (a)) for each separate account. In doing so, please provide a separate schedule for the RSVA Power – Global Adjustment SubAccount.

Response

a) Please refer to Exhibit H, Tab 1, Schedule 110, part a.

b) Please refer to Exhibit H, Tab 1, Schedule 110, part a.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #96 List 1

Interrogatory

Issue: #8.2

Reference: Exhibit F1/Tab 1/Schedule 1, pages 3-6

a) For the Minimum Functionality January 1-December 31, 2008 Account, please provide a schedule that sets out the determination of the revenue requirement recorded in the account. Please also explain how any "revenues" recorded in the account were determined.

b) For the Smart Meter Exceeding Minimum Functionality January – December 2008 Account, please provide:
   1. A schedule that sets out the determination of the revenue requirement recorded in the account.
   2. Details regarding the nature of the activities/equipment for which costs were recorded in this Account.
   3. How any revenues recorded in the Account were determined.

c) Please provide a schedule that compares the actual 2008 capital and OM&A spending for Smart Meters (as recorded for recovery) and the number of smart meters actually installed in 2008 with that forecast for 2008 in EB-2007-0681 and explain any variances of more than 5%.

Response

a)

	2007 MF Approved	2007 MF Not Yet App	2008 MF Not Yet App	Total
OM&A	0.0	0.0	6.9	6.9
Depreciation	0.5	0.9	2.7	4.0
Capital tax	0.0	0.0	0.1	0.1
Return on debt	0.2	0.4	1.3	1.9
Return on equity	0.2	0.4	1.3	1.9
Income tax	0.1	0.1	(1.1)	(0.9)
	1.0	1.8	11.1	14.0
Interest improvement				0.1
Smart Meter Adder Recovered				(13.2)
SM Minimum Functionality Under-Recovery to Dec 31 08				0.9

The Minimum Functionality Account includes 4 months of return in 2008 for 2007 life to date capital expenditures of $21.1M for Minimum Functionality Approved and $38.3M for Minimum Functionality Not Yet Approved and 12 months of return in 2008 for 2008 capital expenditure of $76.4M for Minimum Functionality Not Yet Approved and $6.9M of actual OM&A expenditures. The return is calculated using the revenue requirement model.

The total revenue requirement and interest improvement of $14.1M is offset by revenues collected of $13.2M.

b)

1. Please refer to interrogatory Exhibit H, Tab 1, Schedule 114, part b.

2. The associated activities include ensuring the effective use of the smart meters to provide time-differentiated billing to customers as well as providing Hydro One Distribution the ability to leverage its AMI system for other business benefits. Specific activities include:

   - 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 where time of use rates are an integral part;

   - Integration of the end to end systems including business process redesign and optimizing the handling of transactions and exceptions. This integration ties the AMI systems with the IESO's MDMR and Hydro One Distribution's CIS system to provide ongoing synchronization functionality as well as to enable the collection of time differentiated consumption data required for TOU billing; and

   - Integration of super capacitors in meters and batteries in the regional collectors (AMRC) that enable real time outage reporting after and during power outages.

3. The Exceeding Minimum Functionality Account includes 4 months of return in 2008 for 2007 life to date capital expenditures of $4.9M and 12 months of return in 2008 for 2008 capital expenditure of $15.6M. The return is calculated using the revenue requirement model.

c)

$Millions	2008 Actual	Forecast in EB-2007-0681	Variance from Forecast
# of Smart Meters Installed	456,019	370,000	
Capital Costs			
All Meter Installations	93.0	125.3	Below forecast due to a contingency for meters that was not required and delays in network deployment.
AMI Infrastructure	1.6	3.9	Below budget due to no price increase to the meter head end software license and less cost for head end system hardware servers, partially offset by higher AMI implementation costs.
MDMR Integration	2.5	23.1	Below forecast resulting from the delay in finalizing the MDMR specifications and the resulting changes to the delivery of the MDMR application.
Customer Information System	9.1	12.6	Same as above for MDMR integration.
Total Capital Costs	106.2	164.8	
OM&A Costs	6.9	9.7	Below forecast due to no maintenance requirement for integration systems resulting from delays in finalization of MDMR specifications and a delay in the commissioning of the meter head end system.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #97 List 1

Interrogatory

Issue: #1.1 and #6.1

Reference: i) Exhibit F1/Tab 1/Schedule 1, page 8
ii) OEB Filing Requirements for Transmission and Distribution Applications, May 2009, Section 2.10.1
iii) Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative, July 2009

a) For each of the accounts listed in Section 3.0, please provide a continuity schedule for the period January 1, 2005 to present showing the opening balance, annual adjustments, accruals, interest and closing balance for each year.

b) Please indicate when each of the Rate Riders #2-#4 is scheduled to terminate.

c) There is no reference here to a Rate Rider #5. However, the proposed recovery of the current outstanding balances is designated as Rate Rider #6 (G1/5/1, page 7). Please indicate if there was a Rate Rider #5 and, if so, what the status of the Rate Rider is, including the current Deferral/Variance account balance.

d) In accordance with Reference (iii), page 13, please explain why Hydro One Networks is not proposing disposition of the following accounts:
- Rural or Remote Electricity Rate Protection
- Deferred Pension
- Bill Impact Mitigation

Response

a) Please refer to Exhibit H, Tab 01, Schedule 110, part a.

b) Rate Rider #2 is scheduled to terminate April 30, 2010. Hydro One is proposing that Rider #2 ends at the same time the new 2010 Distribution rates are implemented. Any over/under recovery will be cleared at a future Proceeding.
Rate Rider #3 is scheduled to terminate April 30, 2011.
Rate Rider #4 is scheduled to terminate April 30, 2011.

c) Rate Rider #5 was approved in EB-2008-0187 and comprised revenues associated with the incremental capital relief, tax rate changes, and foregone revenue between May 1, 2009 and May 31, 2009 (fixed and volumetric portions). Rate Rider #5 is to be recovered from June 1, 2009 to April 30, 2010. Hydro One is proposing that rider 5 end at the same time as the new 2010 Distribution rates are implemented. Hydro

One does not intend to recover any shortfall resulting from ending rider 5 before April 30, 2010.

Rate Rider #5 does not have a Deferral/Variance account because there are no assets or liabilities associated with Rider #5. In addition, there is no requirement to track the differences between approved amounts and collected amounts in a variance account.

d) Hydro One Distribution is not requesting disposition of the following accounts due to the following reasons:

- Rural and Remote Electricity Rate Protection (RRRP) – Ontario Regulation 442/01 established an annual true-up mechanism. The balance in the RRRP variance account will decrease with OEB approval of a new RRRP rate as of May 1, 2009. Hydro One collects the RRRP amount paid by all customers in Ontario, not just Hydro One customers. For these reasons Hydro One is not proposing at this time to clear the RRRP variance account.

- Deferred Pension – There was no balance in the Deferred Pension accounts at December 31, 2008.

- Bill Impact Mitigation – The Bill impact mitigation account is still active. Impact mitigation continues to be applied to customers until January 31, 2010, so it would be premature to clear this variance account in this Proceeding.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #98 List 1

Interrogatory

Issue: #6.2

Reference: Exhibit F1/Tab 1/Schedule 2

a) Please explain how the requested Pension Cost Deferral Account differs from the existing Deferred Pension Account.

b) If the Pension Cost Deferral account had existed in 2008, please provide the amount that would have been recorded in the account and the supporting calculations.

c) With respect to the Pension Cost Deferral Account:
- Why is the Account required?
- Why should these costs be treated differently from other cost in the revenue requirement?
- Is this request just for 2010 and 2011 or for a permanent account?
- What are the 2010 and 2011 costs included in the application?

d) If the OEB Cost Differential Account had existed in 2008, please provide the amount that would have been recorded in the account and the supporting calculations.

e) Please provide a schedule that sets out the 2010 and 2011 expenditures include in the current Application and requested revenue requirement for:
- Annual OEB Assessments
- Intervenor Cost Awards
- OEB-initiated Studies.

f) With respect to the OEB Cost Differential Account, please clarify what is meant by OEB-initiated studies. For example, would Hydro One Networks' costs associated with sponsoring Concentric Energy Advisors participation in the current Cost of Capital review be considered an "OEB-initiated study"?

g) With respect to the Bill Impact Mitigation Account, please explain what types of "incremental costs associated with implementing any additional mitigation measures" would be recorded in the account. Were there any such costs associated with implementing the bill impact mitigation measures adopted for the 2008 rates and, if so, what were they?

Response

a) This account is an extension of the existing Pension Cost Deferral Account approved in EB-2007-0681.

b) The Pension Cost Deferral account existed in 2008. There was no amount to recover from customers as the valuation was available and the OEB reduced the pension cost by $1.5M for the purpose of setting 2008 rates in its EB-2007-0681 decision.

c) This account is required please see response at interrogatory Exhibit H, Tab 1, Schedule 117. The cost should be treated differently from other cost in the revenue requirement, since the actuarial valuation which determines the 2010 and 2011 expense will not be finalized until September 2010. There deferral account being requested ensures the ratepayers are not over or under charged given the difficulty in estimating those costs. This request is for 2010 and 2011 rate period. The 2010 and 2011 estimated costs are included in the application in Exhibit C1 Tab 3 Schedule 2, Appendix A.

d) If the OEB Cost Differential Account had existed in 2008, the amount that would have been recorded in the account is $(354)K. Please see Attachment 1 for the supporting calculations.

e)

$ Millions

	DX Allocation	
Description	**2010**	**2011**
Annual OEB Assessments	5.3	4.7
Intervenor Cost Awards	0.8	0.1
OEB-initiated Studies*	0	0

* Hydro One does not budget for OEB-initiated Studies

f) OEB initiated studies relate to work that Hydro One would be required to undertake at the specific direction of the OEB. The Concentric study would not be included in this category as it was not required to be done by the OEB.

g) The costs tracked in the additional mitigation account are the implementation costs and the actual mitigation provided. For 2008, the cost of implementing additional mitigation was approximately $0.1 million required to make changes to the billing system.

Dx OEB Costs Jan 1, 2008 to Dec 31, 2008

Interest Rate	5.14%	Q1 2008
Per Day	0.000140437	
Interest Rate	4.08%	Q2 2008
Per Day	0.000111475	
Interest Rate	3.35%	Q3 and Q4 2008
Per Day	0.000091530	

# Days in Month	Month	Principal	Cum Principal	Interest	Cum Interest	Cum Total
31	Jan-08	(288,240.00)	(288,240.00)	0.00	0.00	(288,240.00)
29	Feb-08	0.00	(288,240.00)	(1,173.91)	(1,173.91)	(289,413.91)
31	Mar-08	0.00	(288,240.00)	(1,254.87)	(2,428.78)	(290,668.78)
30	Apr-08	68,384.00	(219,856.00)	(963.95)	(3,392.73)	(223,248.73)
31	May-08	0.00	(219,856.00)	(759.76)	(4,152.49)	(224,008.49)
30	Jun-08	0.00	(219,856.00)	(735.26)	(4,887.75)	(224,743.75)
31	Jul-08	68,385.00	(151,471.00)	(623.83)	(5,511.57)	(156,982.57)
31	Aug-08	0.00	(151,471.00)	(429.79)	(5,941.36)	(157,412.36)
30	Sep-08	0.00	(151,471.00)	(415.92)	(6,357.29)	(157,828.29)
31	Oct-08	(194,213.00)	(345,684.00)	(429.79)	(6,787.08)	(352,471.08)
30	Nov-08	0.00	(345,684.00)	(949.21)	(7,736.29)	(353,420.29)
31	Dec-08	0.00	(345,684.00)	(980.85)	(8,717.14)	(354,401.14)

Notes:

OEB Cost Assessments per
EB-2007-0681 Exhibit C1 / Tab 2 / Schedule 6 pg 28
Jan 1, 2008 to Dec 31, 2008 5,600,000.00

a)	Base	1,400,000.00
	Jan 1 - March 31 2008 Actual OEB Invoice	1,111,760.00
	Q1 Var for Reg Asset	(288,240.00)
b)	Base	1,400,000.00
	Apr 1 - June 30 2008 Actual OEB Invoice	1,468,384.00
	Q2 Var for Reg Asset	68,384.00
c)	Base	1,400,000.00
	July 1 - Sept 30 2008 Actual OEB Invoice	1,468,385.00
	Q3 Var for Reg Asset	68,385.00
d)	Base	1,400,000.00
	Oct 1 - Dec 31 2008 Actual OEB Invoice	1,205,787.00
	Q4 Var for Reg Asset	(194,213.00)

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #99 List 1

Interrogatory

Issue: #8.1

Reference: Exhibit F1/Tab 1/Schedule 3

a) Please provide a schedule that sets out for the years 2010 and 2011 the capital spending broken down as follows:
   - Spending on Residential Smart Meters – per page 3, lines 13-14
   - Spending on Smart Meters for >50 kW customers – per page 3, lines 15-16
   - Spending on the AMRC and the AMCC – per page 3, lines 18-2

b) Please provide a schedule that sets out the capital spending on smart meter installation, the number of smart meters installed and the average capital cost per installed smart meter incurred annually from 2006 to 2010 (forecast). Please explain any year over year variances.

c) Please explain why there is capital spending for Meter Installations in 2011 (Table 3) when all smart meters will be installed by the end of 2010.

d) Is the OM&A shown in Table 1 – i) the OM&A expense associated with installing Smart Meters each month (assuming all such costs are not capitalized); or ii) the OM&A associated with maintaining the Smart Meters that are in-service. If the later, is it just for the Smart Meters installed in 2010 or for all in-service Smart Meters?

e) Please provide a schedule that sets out the total Smart Meter related OM&A incurred annually for the period 2006-2011 and for each year provide the average number of smart meters in-service. In the same schedule provide a breakdown between the OM&A required: i) to maintain the smart meters in-service; ii) to maintain supporting related hardware, software, telecommunication systems and iii) to install smart meters and related equipment (i.e., assuming all such costs are not capitalized).

Response

a) Please see table below outlining a breakdown of costs as requested.

By Year

$K	**2010 Forecast**	**2011 Forecast**
Spending on Smart Meters	56,887	9,599
Spending on Smart Meters >50 kW customers	791	4,214
Spending on AMRC	15,638	1,161
Spending on AMCC		1,506
Other AMI Capital Costs Related To Minimum Functionality	3,700	2,488
Total	77,016	18,968

b) Please see table below outlining a breakdown of costs as requested.

By Year

$K	**2006 Act**	**2007 Act**	**2008 Act**	**2009 Forecast**	**2010 Forecast**
# of Smart Meters Installed	27,600	222,831	456,019	370,000	115,000
Capital Costs					
All Meter Installations	4,645	64,012	92,999	132,374	80,562
AMI Infrastructure	950	5,074	1,632	2,144	
MDMR Integration	70	3,780	2,465	21,772	16,918
Wimax	968				
Customer Information System	1,035	4,639	9,141	10,421	5,646
CDM Funding - Capital	6,400				
Annual Total	14,067	77,505	106,237	166,710	103,126
Total Cost Per Meter	$509.68	$347.82	$232.97	$450.57	$896.74
% Change from Previous Year		-32%	-33%	93%	99%

See response at Exhibit 1, Tab1, Schedule 143 part b) for a discussion of the variances in total cost per meter.

c) In 2011 we expect to continue to install network devices such as AMRC's and Repeaters and associated backhaul facilities where suitable cellular coverage is not available. These components are included under the heading of "Meter Installations".

d) The OM&A in Table 1 (Exhibit F1, Tab 1, Schedule 3, page 5 of 17), summarizes costs for all meters installed after December 31, 2008. The costs are for maintaining and operating smart meters and network hardware, software and monthly recurring telecommunications charges.

e) Please see table below outlining a breakdown of costs as requested. The installation costs are capitalized.

By Year

$K	**2006 Act**	**2007 Act**	**2008 Act**	**2009 Forecast**	**2010 Forecast**	**2011 Forecast**
# of Smart Meters Installed	27,600	222,831	456,019	370,000	115,000	
OM&A Costs						
Project Setup	4,879					
Maintain Smart Meters in Service		4,605	6,217	10,084	12,968	12,715
Maintain Supported Related Hardware, Software & Telecommunication Systems	25	1,607	727	4,615	9,144	9,630
Annual Total	4,904	6,212	6,945	14,700	22,112	22,345

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #100 List 1

Interrogatory

Issue: #7.1

Reference: i) Exhibit G1/Tab 2/Schedule 3, page 2, lines 2-6
ii) EB-2007-0681, Exhibit H/Tab 12/Schedule 41, part (b)
iii) EB-2007-0681, Exhibit H/Tab 12/Schedule 44, part (b)

Preamble: In Reference (ii) Hydro One Indicated that a study had not been undertaken to determine if R2 Legacy customers qualify for R1 status and that the Company would wait until better information was available from its GIS system. Reference (iii) outlines the process customers should follow if they want to question their density classification.

a) With respect to Reference (ii), was such a study undertaken for the current Application?

b) If yes, please provide the results.

c) If no, what initiatives have been undertaken to improve the customer connectivity and lines detail in the GIS system and when will such a review be performed?

d) With respect to Reference (iii), how many customers reclassified in 2008 as a result of customer queries?

Response

a) No. A comprehensive review of R2 Legacy customers to see if any qualified for R1 status has not been undertaken.

b) Not Applicable

c) Hydro One is undertaking an initiative to process and consolidate DX spatial asset information which will also include linking customers to Distribution Assets. This work is targeted for completion in 2012.

A comprehensive density review of R2 Legacy customers is not included in the work plans covered by the test years in this application. Once GIS is fully available the feasibility of performing comprehensive density reviews utilizing the new solution will be evaluated some time after it is available in 2012.

d) In 2008 38 customers were reclassified as a result of customer queries.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #101 List 1

Interrogatory

Issue: #7.1

Reference: Exhibit G1/Tab 2/Schedule 3, page 9

a) Please explain how generators that meet the eligibility requirements under the OPA's FIT and microFIT programs will be "classified" for purposes of cost allocation and rates.

b) What assumptions has Hydro One made in the current Application regarding the number of such customers in 2010 and 2011 (i.e., number, load, etc.)?

c) Please reconcile the response to part (b) with the number of new generator connections assumed in Exhibit D1/Tab 3/Schedule 3, pages 10-11.

Response

a) Generators that meet the eligibility requirements for OPA's FIT program will be classified as directed by the OEB in *"Notice of a Proceeding to Determine a Just and Reasonable Rate to Recover the Costs Associated With Embedded Generators Having a Nameplate Capacity of 10 kW or Less, Procedural Order No. 1"* issued September 21, 2009 under Proceeding EB-2009-0326.

b) Please refer to Exhibit H, Tab 1, Schedule 54, line 53 – 55.

c) Exhibit H, Tab 1, Schedule 54, line 53 – 55 only includes assumptions for the number of FIT and microFIT generators. Exhibit D1, Tab 3, Schedule 3, pages 10 – 11 as noted in lines 13 – 15 of page 11, is based on the number of applications received under the RESOP program and makes provision for demand under the FIT program. As noted in Table 3, the numbers in this exhibit exclude micro-generators which is the size that is eligible for the OPA's microFIT program.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #102 List 1

Interrogatory

Issue: #7.3 and #7.4

Reference: Exhibit G1/Tab 2/Schedule 4, pages 3-5

a) Please confirm that the "group" referred to on page 4 (lines 12-14) refers to all Urban Residential customers including both the Legacy and Acquired UR customers.

b) Please explain why the current acquired fixed charges are "truncated downward" as opposed to simply using the actual and adjusting it ½ the way to the target rate (page 3).

Response

a) Yes, the "group" referred to on page 4 (lines 12-14) in Exhibit G1, Tab 2, Schedule 4, pages 3-5 refers to all Urban Residential customers including both legacy and Acquired UR customers.

b) Acquired fixed charges are truncated downward rather than using the actual service charge and then adjusting it in order to reduce the number of basic distribution rates. Using the actual existing service charge and adjusted to ½ the way to the target rate would have resulted in 88 Service Charges for the Acquireds in the R1 rate class.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #103 List 1

Interrogatory

Issue: #7.4

Reference: Exhibit G1/Tab 2/Scheduel 4, pages 6-7

a) Does the General Service class in Table 3 include all four GS classes?

b) Are the impacts shown in Table 3 based on specific customer consumption profiles and, if so, what is the profile used for each class?

c) Please produce a comparable table for 2011.

d) With respect to page 7 (lines 24-27), please explain what is meant reference to "on average" when discussing 2010 bill impacts.

Response

a) Yes the General Service class in Table 3 includes all four GS customers.

b) Yes the impacts are based on specific customer profiles as follows:

- General Service Energy Billed and Urban General Service Energy Billed customer impacts are based on average consumption of 2000 KWh per month
- General Service Demand Billed and Urban General Service Demand Billed customer impacts are based on average consumption of 36 MWh and 117 kw.

c) The table below provides the range of impacts for Acquired Residential and General Service in 2011. To measure the impacts, it is assumed customers have already harmonized to 2010 end state rates. Revenue requirement and smart meter charge for 2011 are estimated at 10.39% and $4.45 respectively.

Customer Class	Number of customers	Range of impacts on total bill (percent)
Residential	139,991	4.2 to 7.7
General Service	21,484	3.8 to 5.2

d) Reference to the term “on average” on page 7 (lines 24-27) in Exhibit G1, Tab 2, Schedule 4 refers to the average consumption level for each rate class upon which bill impact are calculated.

For details on the average consumption levels used to estimate the impact for each rate class, please refer to Exhibit H, Tab 7, Schedule 113.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #104 List 1

Interrogatory

Issue: #1.1

Reference: i) Exhibit G1/Tab 2/Schedule 5
ii) Exhibit G1/Tab 2/Schedule 5, Attachment 1

a) On page 2 Hydro One Networks states that it believes "a staged approach to addressing the Board direction is a reasonable way to proceed". Please indicate what Hydro One Networks considers to be the various stages in its approach and when they will be undertaken.

b) Does Hydro One Networks agree that there is a distinction between incorporating density considerations in the cost allocation process and defining customer classes based on density as Elenchus has done on pages 2-4 of Reference (ii)? For example, one could not use density-based customer class definitions but still include density considerations in the cost allocation methodology in order to more fairly allocate the costs between customer classes. If not, please explain.

c) Please indicate whether or not ERA's survey of other jurisdictions (Reference (ii), page 3) examined whether density was used elsewhere in utilities' cost allocation methodologies as opposed to in their definition of customers. If yes, what were the findings?

Response

a) The first stage was to identify the principles that could be applied if Hydro One undertook the study to determine the relationship between density and costs. This approach was agreed upon by the majority of stakeholders. Please see Exhibit H, Tab 1, Schedule 123.

The next stage will be determined on the basis of the direction provided by the Board with respect to the principles it endorses with respect to density based rates. In particular, before undertaking an expensive and time consuming methodology for defining density based residential and GS classes, and allocating costs to those classes, it would be desirable for the Board to provide direction as to (i) the appropriateness of maintaining separate urban and rural classes, (ii) the preferred approach to assigning customers to the urban and rural classes if they are maintained (e.g., municipal boundaries rather than density criteria; and (iii) whether it considers cost-effective proxy methods for allocating costs to urban and rural classes to be appropriate.

b) It is not clear how density could be used to allocate costs to classes that are not based on a density-based definition, or a proxy such as the separation of the residential (and GS) classes into urban and rural residential (and GS) classes. For example, HONI is not aware of any precedents for allocating costs between residential and GS classes on the basis of the density of customers within those classes.

c) ERA did not review the use of customer density in cost allocation studies in other jurisdictions.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #105 List 1

Interrogatory

Issue: #7.1

Reference: Exhibit G1/Tab 2/Schedule 5

a) On pages 2-3 Hydro One Networks notes that the weighting factor for Seasonal customers was set to one, as is done for other customer classes that have no density based weighting.
   - Please confirm that the setting of the Seasonal class weighting factor to one was done for purpose of Cost Allocation. If not, please explain.
   - Please confirm that that the reference to other customer classes that have no density based weighting was with regard to other customer classes "definition".

b) Please indicate the impact on the cost allocation results shown at Exhibit G1/Tab 3/Schedule 1, page 3 if the density weightings were retained for the Seasonal class.

Response

a) Yes, the seasonal class weighting was set to one for cost allocation purposes. This is a similar approach to all other customer classes that have no density based differentiation.

Yes, the following classes have no density based weighting:
- Distributed Generation
- Street Light
- Sentinel Light
- Sub Transmission Class and
- Seasonal class.

b) The table below compares the current proposed cost allocation results with the results if the density weights were retained for Seasonal class.

	UR	R1	R2	Seasonal	UGSe	UGSd	GS e	GS d	ST	DG	Street Light	Sen Light	Total
Rev/cost ratio with new Seasonal Density	**1.09**	**0.93**	**1.04**	**1.03**	**1.20**	**1.25**	**1.07**	**0.88**	**1.01**	**1.00**	**0.70**	**0.70**	**1.00**
Proposed Rev/cost ratio EB-2009-0096	**1.09**	**0.92**	**1.02**	**1.15**	**1.20**	**1.25**	**1.07**	**0.89**	**1.01**	**1.00**	**0.70**	**0.70**	**1.00**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #106 List 1

Interrogatory

Issue: #7.1

Reference: Exhibit G1/Tab 3/Schedule 1

a) With respect to page 1 (lines 17-20), please indicate where in its Decision regarding EB-2007-0681 the Board explicitly discusses and approves Hydro One Networks' modified cost allocation methodology.

b) Please confirm that the "Revenue Adjusted at Current Rates" row in Table 1 is net of any discounts for transformer ownership or the USL meter credit.

Response

a) The OEB in its decision on Proceeding EB-2007-0681 did not explicitly approved Hydro One's cost allocation methodology, but by the OEB having approved the new proposed 12 customer classes, the customer classes revenue to cost ratios, the fixed and variable distribution rates for Hydro One, all of which affect or are a result of the cost allocation study, the OEB implicitly approved Hydro One's cost allocation methodology.

b) Yes, "Revenue Adjusted at Current Rates" in Table 1 Exhibit G1, Tab 3, Schedule 1, is net of any discounts for transformer ownership and USL meter credits.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #107 List 1

Interrogatory

Issue: #7.3

Reference: i) Exhibit G1/Tab 4/Schedule 1
ii) Exhibit G1/Tab 4/Schedule 2, page 2

a) With respect to Reference (i), page 1 (lines 21-23), please provide a schedule that sets out for each customer class (except DG and R2) whether the proposed fixed charges (per Reference (ii)) were set based on i) avoided cost from the cost allocation study or ii) the service charge from the predominant class. If the latter, please indicate what was considered to be the "predominant class" and whether the proposed fixed charge is based on the current (2009) service charge or the 2009 service charge escalated by the average rate increase for the class.

b) For DG and R2 customers please clarify whether the fixed charge is set at the current 2009 level or at the 2009 level escalated by the average rate increase for the class.

c) The Application states (Reference (i), page 2, line 3) that the only incremental facility required for a micro-generator is a meter.
- This assumes that all micro-generators situated at the same location as the customer's main account. Please explain why this assumption is reasonable and how Hydro One will treat the micro-generator if this is not the case.
- Please confirm that the USL credit includes OM&A costs for meter reading. Does it also include any allowance for billing cost and, if not, should the charge to micro-generators reflect such costs?

Response

a) The table below shows how the proposed fixed charge was determined, by either avoided costs for the cost allocation study or the service charge of the predominant class. If the later is used, the fixed charge is based on the 2009 service charge.

	Proposed fixed charge determinant		Predominant Class
Rate Class	Avoided Cost	Predominant Class Service Charge	
UR		Yes	UR
R1		Yes	R1 Legacy
Seasonal		Yes	R3
GSe		Yes	G1 Legacy
GSd		Yes	G3 Legacy
UGe		Yes	UGe
UGd	Yes		UGd
St Lgt		Yes	Street Light
Sen Lgt		Yes	Sentinel Light

b) For both DG and R2 customers, the fixed charge is set at the current 2009 level.

c)

- It is expected that generators that meet the eligibility requirements for OPA's microFIT program will be installed at an existing load customer connection in order to minimize the cost of connection incurred by the generator. Generators pay all connections costs. In order to connect a micro-generator on a standalone basis, the generator would incur the cost of a transformer, switch, meter & conductor plus installation. It is expected that these incremental costs would make such an installation uneconomic. Further, due to the OPA pricing schedule, the majority of micro-generator installations are expected to be rooftop installations.

- Yes, the USL credit includes OM&A costs for meter reading. It does not include any allowances for billing costs as shown in Exhibit G2, Tab 1, Schedule 1, Attachment 1 Tab O3.5 (USL meter credit).

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #108 List 1

Interrogatory

Issue: #7.3

Reference: Exhibit G1/Tab 4/Schedule 2, pages 2-3

a) Please confirm that the proposed fixed and variable charges set out in Table 1 will recover revenue requirement allocated to each class per the proposed revenue to cost ratios set out at Exhibit G1/Tzab 3/Schedule 1, Table 1 (after also allowing for the recovery of the USL and CSTA credits).

Response

a) Yes, the proposed fixed charges set out in Table 1 of Exhibit G1, Tab 4, Schedule 2 are set to recover the revenue requirement allocated to each class per the proposed revenue to cost ratios set out in Exhibit G1, Tab 3, Schedule 1, Table 1. The fixed charges allow for the recovery of the USL credit. CSTA credit is not included in this table.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #109 List 1

Interrogatory

Issue: #7.3

Reference: i) Exhibit G1/Tab 4/Schedule 3, pages 2-7
ii) Exhibit G2/Tab 4/Schedule 1

a) With respect to Reference (i), please confirm that the difference between the energy rates set out in Tables 1 and 2 for each class is due to the fact the rates in Table 2 have been increased to recover the revenue shortfall due to the phase-in of the target service charges.

b) Please confirm that in principle the energy rates set out in Reference (i), Table 2 for each class should be the same as those proposed for the same class in Reference (ii) and any differences are due to rounding.

Response

a) No, the difference between Table 1 and 2 in Exhibit G1, Tab 4, Schedule 3 is not due to increased rates to recover the revenue shortfall. Table 1 shows the proposed target rates in 2010 for all customers in a particular class. As the Acquired LDC customers are still on the harmonization path, these rates are used to derive the harmonized rates for customers over the remaining two year period. Table 2 shows the rates for 2010 (third step of the Harmonization Plan) for the Acquired LDCs customer classes prior to the application of any mitigation.

b) Yes, in principle the energy rates set out in Exhibit G1, Tab 4, Schedule 3, Table 2 should be the same as those proposed in Exhibit G2, Tab 4, Schedule 1 for the same rate class at the end of the Harmonization plan. Yes, any difference is due to rounding.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #110 List 1

Interrogatory

Issue; #7.4

Reference: Exhibit G1/Tab 4/Schedule 7

a) It is noted that the harmonization period for the Low Use Secondary Customer rate is 5 years as opposed to the 4 years used for other classes. Please provide a schedule that sets out the 2010 bill impacts for these customers of using a 4 year versus a 5 year period.

Response

a) Please see attached schedule that sets out 2010 bill impacts for Low Use Secondary customers using a 4 year harmonization path.

Total Bill Impacts of Proposed Distribution Rates:

Classes		Scenario			2009 + IRM Incl Rate Riders									Existing Dx	2010 Incl Rate Riders							New Dx	Non-Dx Compoent					Other Reg		600.0 Commodity Bands				Existing	New	$ Incr	% Incr
Low Use New Class	Old Class	kWh	kW	LF	SrChg [$/cust]	Rider4 [$/cust]	base [c/kWh]	Rider2 [$/cust]	Rider3 [$/cust]	Rider4 [c/kWh]	Rider 5ab [$/cust]	VarChg [$/cust]	[$/month]		SrChg [$/cust]	Rider4 [$/cust]	base [c/kWh]	Rider3 [c/kWh]	Rider4 [c/kWh]	Rider 6 [c/kWh]	VarChg [c/kWh]	[$/month]	RTSR old c/kWh	RTSR new c/kWh	WMSC c/kWh	DRC c/kWh	TLF	Old $	New $	Band 1 5.7 kWhs	Band 2 6.6 kWhs	Old Total $	New Total $	Total Bill [$/month]	Total Bill [$/month]	Total Bill $	Total Bill %
GSe	F1	50			13.71	1.00	3.298	0.100	(0.130)	0.384	0.062	3.714	16.57		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	27.23	0.73	0.69	0.65	0.70	1.092	1.10	1.08	50	-	3.11	3.11	20.78	31.43	10.64	51.2%
Low Use Secondary		75			13.71	1.00	3.298	0.100	(0.130)	0.384	0.062	3.714	17.50		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	28.15	0.73	0.69	0.65	0.70	1.092	1.66	1.62	75	-	4.67	4.67	23.82	34.44	10.62	44.6%
		100			13.71	1.00	3.298	0.100	(0.130)	0.384	0.062	3.714	18.43		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	29.07	0.73	0.69	0.65	0.70	1.092	2.21	2.17	100	-	6.22	6.22	26.86	37.46	10.60	39.5%
		125			13.71	1.00	3.298	0.100	(0.130)	0.384	0.062	3.714	19.35		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	29.99	0.73	0.69	0.65	0.70	1.092	2.76	2.71	125	-	7.78	7.78	29.89	40.48	10.59	35.4%
		150			13.71	1.00	3.298	0.100	(0.130)	0.384	0.062	3.714	20.28		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	30.91	0.73	0.69	0.65	0.70	1.092	3.31	3.25	150	-	9.34	9.34	32.93	43.50	10.57	32.1%
		200			13.71	1.00	3.298	0.100	(0.130)	0.384	0.062	3.714	22.14		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	32.75	0.73	0.69	0.65	0.70	1.092	4.41	4.33	200	-	12.45	12.45	39.00	49.53	10.53	27.0%
		400			13.71	1.00	3.298	0.100	(0.130)	0.384	0.062	3.714	29.57		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	40.11	0.73	0.69	0.65	0.70	1.092	8.83	8.66	400	-	24.90	24.90	63.29	73.67	10.38	16.4%
GSe	F3	50			13.71	1.00	3.298	0.040	(0.130)	0.384	0.062	3.654	16.54		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	27.23	0.73	0.69	0.65	0.70	1.092	1.10	1.08	50	-	3.11	3.11	20.75	31.43	10.67	51.4%
Low Use Secondary		75			13.71	1.00	3.298	0.040	(0.130)	0.384	0.062	3.654	17.45		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	28.15	0.73	0.69	0.65	0.70	1.092	1.66	1.62	75	-	4.67	4.67	23.78	34.44	10.67	44.9%
		100			13.71	1.00	3.298	0.040	(0.130)	0.384	0.062	3.654	18.37		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	29.07	0.73	0.69	0.65	0.70	1.092	2.21	2.17	100	-	6.22	6.22	26.80	37.46	10.66	39.8%
		125			13.71	1.00	3.298	0.040	(0.130)	0.384	0.062	3.654	19.28		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	29.99	0.73	0.69	0.65	0.70	1.092	2.76	2.71	125	-	7.78	7.78	29.82	40.48	10.66	35.8%
		150			13.71	1.00	3.298	0.040	(0.130)	0.384	0.062	3.654	20.19		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	30.91	0.73	0.69	0.65	0.70	1.092	3.31	3.25	150	-	9.34	9.34	32.84	43.50	10.66	32.5%
		200			13.71	1.00	3.298	0.040	(0.130)	0.384	0.062	3.654	22.02		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	32.75	0.73	0.69	0.65	0.70	1.092	4.41	4.33	200	-	12.45	12.45	38.88	49.53	10.65	27.4%
		400			13.71	1.00	3.298	0.040	(0.130)	0.384	0.062	3.654	29.33		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	40.11	0.73	0.69	0.65	0.70	1.092	8.83	8.66	400	-	24.90	24.90	63.05	73.67	10.62	16.8%
GSe	G1	50			13.71	1.00	3.298	0.090	(0.130)	0.384	0.062	3.704	16.56		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	27.23	0.73	0.69	0.65	0.70	1.092	1.10	1.08	50	-	3.11	3.11	20.78	31.43	10.65	51.2%
Low Use Secondary		75			13.71	1.00	3.298	0.090	(0.130)	0.384	0.062	3.704	17.49		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	28.15	0.73	0.69	0.65	0.70	1.092	1.66	1.62	75	-	4.67	4.67	23.81	34.44	10.63	44.6%
		100			13.71	1.00	3.298	0.090	(0.130)	0.384	0.062	3.704	18.42		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	29.07	0.73	0.69	0.65	0.70	1.092	2.21	2.17	100	-	6.22	6.22	26.85	37.46	10.61	39.5%
		125			13.71	1.00	3.298	0.090	(0.130)	0.384	0.062	3.704	19.34		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	29.99	0.73	0.69	0.65	0.70	1.092	2.76	2.71	125	-	7.78	7.78	29.88	40.48	10.60	35.5%
		150			13.71	1.00	3.298	0.090	(0.130)	0.384	0.062	3.704	20.27		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	30.91	0.73	0.69	0.65	0.70	1.092	3.31	3.25	150	-	9.34	9.34	32.91	43.50	10.58	32.1%
		200			13.71	1.00	3.298	0.090	(0.130)	0.384	0.062	3.704	22.12		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	32.75	0.73	0.69	0.65	0.70	1.092	4.41	4.33	200	-	12.45	12.45	38.98	49.53	10.55	27.1%
		400			13.71	1.00	3.298	0.090	(0.130)	0.384	0.062	3.704	29.53		25.01	0.38	3.828	(0.130)	0.040	(0.057)	3.681	40.11	0.73	0.69	0.65	0.70	1.092	8.83	8.66	400	-	24.90	24.90	63.25	73.67	10.42	16.5%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #111 List 1

Interrogatory

Issue: #7.6

Reference: Exhibit G1/Tab 5/Schedule 1

a) Are the factors used to allocate the balances to customer classes consistent with the Board's Direction in its July 2009 Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EB-2008-0046)?

b) If there are instances where the response to (a) is no, please recalculate the allocation and the resulting adders based on the Board's direction.

c) Please explain more fully what the RSVA Provincial Benefit represents and why it is allocated to non-market participants.

d) Why is there no RSVA-Power (excluding the Global Adjustment Sub-Account) or RSVA –Global Adjustment Sub-Account balances to be refunded or recovered?

Response

a) The factors used to allocate variance accounts balances between customer classes in Exhibit G1, Tab 5, Schedule 1 are compared in the following Table with the factors from Table 1, page 21, of the Board Report in Proceeding EB-2008-0046 dated, July 31, 2009.

1

Account	EB-2009-0096	EB-2008-0046	Comments
RARA 1	2008 Actual RARA # 1 revenues	Residual Account balance to be allocated to rate classes in proportion to the recovery share as established when rate riders were implemented	The customer classes used in establishing RARA # 1 are different than the customer classes approved by the OEB in EB-2007-0681. Hydro One mapped the old classes to the new classes to develop the allocators
RSVA Wholesale Market Service Charge	GWh excl. Wholesale Market Participants	kWh	Wholesale Market Participants are billed by the IESO directly, so these customers should not be allocated any balances. This is also consistent with previous OEB approvals of Hydro One allocators
RSVA TX Network	GWh	kWh	same
RSVA TX Connection	GWh	kWh	same
RSVA LV	GWh	kWh	same
RSVA Provincial Benefit	GWh excl. Wholesale Market Participants	kWh for non-RPP customers	Hydro One used the same allocator as approved by the OEB for EB-2007-0681
RCVA	# of customers	# of customers	same
Smart Meter Minimum Functionality to December 31, 2008	# of customers	Case-by case basis	
Smart Meter Exceeding Minimum Functionality	# of customers	Case-by case basis	

b) Rider # 6 has been re-calculated, please see Attachment 1, using the allocators recommended in EB-2008-0046 for the following accounts:
- RSVA Wholesale Market Service charge
- RSVA Provincial Benefit

c) RSVA-Provincial Benefit is otherwise known as the RSVA Global Adjustment Sub-Account. This balance represents the difference between the global adjustment that Hydro One pays to purchase power and the global adjustment recovered from non-RPP customers. It is allocated to non-market participants as market-participants would be paying the global adjustment directly to the IESO for the electricity they consume off the grid. RSVA Provincial Benefit is allocated to non-market participants consistent with the allocator used by Hydro One in EB-2007-0681.

d) Please refer to Exhibit H, Tab 1, Schedule 110, part e).

EB-2009-0096 – EXHIBIT G1, TAB 5, SCHEDULE 1, ATTACHMENT 1

Determination of Rate Rider Amounts by Rate Class

RIDER # 6

		2010 statistics		UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST
2	# of Customers	1,195,542		140,540	412,455	367,107	156,901	98,776	7,361	10,577	1,130	-	-	88	607
3	GWh	36,168		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4	17,938
4	GWh excl LDC May 1, 08 to Jan 31, 09	22,777		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4	4,547
5	GWh excl WMP	23,303		1,311	4,397	5,375	718	2,196	3,122	364	600	122	21	4	5,073
5 a	*GWh excl WMP and RPP 2008 data*	*9,188*		*236*	*569*	*466*	*13*	*324*	*2,076*	*54*	*440*	*22*	*2*	*3*	*4,981*
5b	*billing kW excl WMP and RPP 2008 data*	*19,618,717*							*6,217,826*		*1,116,216*			*52,011*	*12,232,664*
6	Billing kWs	45,542,866							10,389,644		1,898,173			66,329	33,188,720
7	2008 RARA # 1 Revenue	100%		8.03%	23.18%	25.42%	7.52%	7.52%	6.46%	0.81%	1.18%	0.18%	0.06%	0.02%	19.62%
8	**Rider # 6 Development**														
9		$ 1000s	Allocator												
10	RARA 1	$ (22,975)	2008 RARA # 1 Rev	(1,843.91)	(5,326.07)	(5,840.69)	(1,727.66)	(1,727.44)	(1,483.98)	(187.02)	(270.00)	(40.34)	(14.08)	(5.28)	(4,508.46)
11	RSVA Wholesale Mkt SrChg	$ (18,710)	*GWh*	*(678.18)*	*(2274.56)*	*(2780.47)*	*(371.42)*	*(1135.98)*	*(1615.00)*	*(188.30)*	*(310.38)*	*(63.11)*	*(10.86)*	*(2.07)*	*(9279.28)*
12	RSVA Tx Network May 1, 08 to Jan 31, 09	$ (14,834)	GWh exc LDC	$ (853.84)	$ (2,863.71)	$ (3,500.67)	$ (467.62)	$ (1,430.23)	$ (2,033.32)	$ (237.07)	$ (390.77)	$ (79.46)	$ (13.68)	$ (2.61)	$ (2,961.41)
13	RSVA Tx Connection May 1, 08 to Jan 31, 09	$ (2,836)	GWh exc LDC	$ (163.21)	$ (547.38)	$ (669.13)	$ (89.38)	$ (273.38)	$ (388.66)	$ (45.31)	$ (74.69)	$ (15.19)	$ (2.61)	$ (0.50)	$ (566.06)
14	RSVA Tx Network Feb 1, 09 to Dec 31, 09	$ 7,657	GWh	$ 277.54	$ 930.85	$ 1,137.89	$ 152.00	$ 464.90	$ 660.93	$ 77.06	$ 127.02	$ 25.83	$ 4.45	$ 0.85	$ 3,797.49
15	RSVA Tx Connection Feb 1, 09 to Dec 31, 09	$ 3,575	GWh	$ 129.60	$ 434.66	$ 531.34	$ 70.98	$ 217.08	$ 308.62	$ 35.98	$ 59.31	$ 12.06	$ 2.08	$ 0.40	$ 1,773.24
16	RSVA LV Wheeling	$ 2,660	GWh	$ 96.40	$ 323.33	$ 395.25	$ 52.80	$ 161.48	$ 229.57	$ 26.77	$ 44.12	$ 8.97	$ 1.54	$ 0.29	$ 1,319.06
17	RSVA Provincial Benefit	$ 19,571	*GWh excl WMP and RPP*	*503.54*	*1211.04*	*993.64*	*27.96*	*689.54*	*4422.48*	*115.61*	*937.73*	*47.61*	*5.11*	*7.35*	*10609.86*
18	RCVA	$ (1,959)	# of Customers	$ (230.27)	$ (675.79)	$ (601.49)	$ (257.08)	$ (161.84)	$ (12.06)	$ (17.33)	$ (1.85)	$ -	$ -	$ (0.14)	$ (0.99)
19	Smart Meter Minimum Functionality to December 31, 200	$ 877	# of Customers	$ 103.07	$ 302.49	$ 269.23	$ 115.07	$ 72.44	$ 5.40	$ 7.76	$ 0.83	$ -	$ -	$ 0.06	$ 0.45
20	Smart Meter Costs Exceeding Minimum Functionality	$ 1,141	# of Customers	$ 134.12	$ 393.62	$ 350.35	$ 149.74	$ 94.27	$ 7.02	$ 10.09	$ 1.08	$ -	$ -	$ 0.08	$ 0.58
21	**Total Regulatory Assets for Approval**	$ (25,832)													
22															
23		$ (25,832.3)		$ (2,525.1)	$ (8,091.5)	$ (9,714.8)	$ (2,344.6)	$ (3,029.2)	$ 101.0	$ (401.8)	$ 122.4	$ (103.6)	$ (28.1)	$ (1.6)	$ 184.5
24															
25	Assuming a 24 month recovery	$ (12,916.2)		$ (1,262.6)	$ (4,045.8)	$ (4,857.4)	$ (1,172.3)	$ (1,514.6)	$ 50.5	$ (200.9)	$ 61.2	$ (51.8)	$ (14.0)	$ (0.8)	$ 92.2
26	*Rider 6 a*	*$ (22,701.9)*		*$ (1,514.3)*	*$ (4,651.3)*	*$ (5,354.2)*	*$ (1,186.3)*	*$ (1,859.4)*	*$ (2,160.7)*	*$ (258.7)*	*$ (407.7)*	*$ (75.6)*	*$ (16.6)*	*$ (4.5)*	*$ (5,212.7)*
27	*Rider 6 b*	*$ 9,785.7*		*$ 251.8*	*$ 605.5*	*$ 496.8*	*$ 14.0*	*$ 344.8*	*$ 2,211.2*	*$ 57.8*	*$ 468.9*	*$ 23.8*	*$ 2.6*	*$ 3.7*	*$ 5,304.9*
28	*Rider # 6 a ¢/kWh*			*(0.116)*	*(0.106)*	*(0.100)*	*(0.165)*	*(0.085)*	*(0.069)*	*(0.071)*	*(0.068)*	*(0.062)*	*(0.079)*	*(0.111)*	Note 1
29	*$/kW*								*(0.21)*		*(0.21)*			*(0.07)*	Note 1
	Rider # 6 b ¢/kWh			*0.107*	*0.107*	*0.107*	*0.107*	*0.107*	*0.107*	*0.107*	*0.107*	*0.107*	*0.107*	*0.107*	Note 1
	$/kW								*0.36*		*0.42*			*0.07*	Note 1
30	Note 1: Rider 6a = $0.034/kW, Rider 6b $0.056/kW, Rider 6c $(0.189)/kW														

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #112 List 1

Interrogatory

Issue: #7.4

Reference: Exhibit G1/Tab 7/Schedule 1

a) Please provide the average customer definition used for each Rate Class (per page 1, lines 15-16).

b) Please confirm that the rate impacts discussed in this section are prior to any phase-in or impact mitigation plan.

Response

a) Average customer definition used for each rate class is provided below:

Rate Class	Average Customer
Residential- UR	1000 kWh
Residential - Medium Density (R1)	1000 kWh
Residential - Low Density (R2)	1000 kWh
Seasonal Residential	500 kWh
Urban General Service Energy Billed	2000 kWh
General Service Energy Billed	2000 kWh
Urban General Service Demand Billed	36MWH+117 kW
General Service Demand Billed	36MWH+117 kW
General Service Energy Billed - unmetered	500 kWh
Distributor Generator	35MWH + 90kW

b) Yes, the rate impacts discussed in Exhibit G1, Tab 7, Schedule 1 are prior to any phase in or mitigation.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #113 List 1

Interrogatory

Issue: #7.4

Reference: i) Exhibit G1/Tab 7/Schedule 2

a) Please confirm that the rate impacts discussed in this section are prior to any phase-in or impact mitigation plan.

Response

a) Yes, the rate impacts discussed in Exhibit G1, Tab 7, Schedule 2 are prior to any phase in or mitigation plan.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #114 List 1

Interrogatory

Issue: #7.4

Reference: Exhibit G1/Tab 4/Schedule 1

a) How many customers are there in the new Seasonal class in total and, with respect to page 1 (lines 13-15), how many customers in the new Seasonal class fall into each of the following categories:
- Were formally R3 customers and have an average monthly usage greater than 1,500 kWh
- Were formally R4 customers and have an average monthly usage greater than 2,000 kWh
- Were formally Caledon OH 07 customers and have an average monthly usage greater than 1,000 kWh.

b) The text on pages 2-3 states that the volumetric charges were lowered so as to meet the 10% bill impact limit. Why were the volumetric charges reduced as opposed to reducing the fixed service charge?

c) The text on page 3 states that the revenue short fall from this specific initiative is being absorbed by the Legacy customers.
- What is the amount of the shortfall?
- Does this mean that the volumetric Rate for Legacy customers will be different (i.e., higher) than for Acquired LDC customers assigned to the same class who are not subject to this specific mitigation initiative?
- What is the impact on the volumetric rates for each Legacy customer class?

d) 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.

e) On the Schedule provided in response to part (d) please indicate of those customers 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 Fenelon Falls residential customers that use less than 500 kWh per month.
- The number of former Kirkfield residential customers that use less than 250 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 250 kWh per month.
- The number of former Thorndale residential customer that use less than 250 kWh per month.
- The number of former Tweed residential customers that use less than 250 kWh per month
- The number of former Woodville residential customers that use less than 250 kWh per month.

Response

a) The table below gives a breakdown of the Seasonal customer class based on 2008 data, as requested.

	Old Rate Class		
Seasonal	R3	R4	Caledon OH 07
Total	71400	85000	210
Greater than 1000			90
Greater than 1500	3530		
Greater than 2000		3670	

b) The volumetric charge is reduced to meet the 10% bill impact limit as opposed to the fixed charge as the former charge is more dominant in a customer's bill based on average consumption.

c)

- The amount of the shortfall being absorbed by Legacy Customers is $280,000.

- Yes, the volumetric Rate for Legacy customers will be different (i.e., higher) than Acquired customers in the same class who are not subject to the mitigation initiatives.

- The impact on Legacy customers volumetric rates for absorbing the revenue shortfall is shown in the table below for all the affected rate classes:

	Impact on volumetric rates	
Rate Class	Increase in Cents/ kWh	Percentage increase
R1	0.001	0.03%
GSe	0.011	0.33%
GSe unmetered	0.101	2.20%

d) The new R1 rate class composition is listed in the following table by Legacy Rate Class and Acquired Distributor, based on 2008 data.

Rate Class or Acquired Distributor	Number of Customers
R1	320,683
Ailsa Craig	344
Arkona	215
Arnprior	708
Arran-Elderslie	1,707
Artemesia	415
Bancroft	1,056
Bath	823
Blandford-Blenheim	869
Blyth	383
Bobcaygeon	1,688
Brighton	2,613
Brockville	1,143
Caledon CH 02	1,999
Campbellford-Seymour	1,463
Carleton Place	542
Cavan-Millbrook-North Monaghan	592
Centre Hastings	687
Chalk River	393
Champlain	1,735
Cobden	467
Deep River	1,750
Deseronto	695
Dryden	2,718
Dundalk	717
Durham	1,138
Eganville	558
Erin	897
Exeter	2,062
Fenelon Falls	971
Forest	1,181
GBE	1,158
Georgina	1,132
Glencoe	876
Grand Bend	1,024
Hastings	526
Havelock	530
Kirkfield	103
Lanark Highlands	339
Larder Lake	379

Rate Class or Acquired Distributor	Number of Customers
Latchford	191
Lindsay	1,416
Lucan Granton	905
Malahide	234
Mapleton	738
Markdale	647
Marmora	603
McGarry	291
Meaford	2,135
Middlesex Centre	391
Napanee	2,172
Nipigon	717
North Dorchester	697
North Dundas	1,579
North Glengarry	1,988
North Grenville	1,464
North Perth	2,504
North Stormont	333
Omemee	521
Perth	531
Perth East	535
Prince Edward	3,261
Quinte West	1,741
Rainy River	381
Ramara	100
Red Rock	373
Rockland	3,930
Russell	900
Schreiber	576
Severn	577
Shelburne	1,890
Smiths Falls	733
South Glengarry	452
South River	491
Springwater	793
Stirling-Rawdon	839
Thedford	296
Thessalon	554
Thorndale	135
Thorold	1,646
Tweed	676
Wardsville	153
Warkworth	261
West Elgin	1,006
Whitchurch Stouffville	279

Rate Class or Acquired Distributor	Number of Customers
Wiarton	898
Woodville	316
Wyoming	834
Terrace Bay	826

e) 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 2008 consumption data, as well as showing the total projected customers mapping to the new R1 rate class.

Type	LT 250	LT 500	Total R1
Ailsa Craig	23		344
Arkona		90	215
Fenelon Falls		263	971
Kirkfield	5		103
Perth East		121	535
Quinte West	161		1,741
Thorndale	11		135
Tweed	56		676
Woodville	8		316

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #115 List 1

Interrogatory

Issue: #7.4

Reference: Exhibit G1/Tab 9/Schedule 1

a) What is Hydro One Networks' proposal for 2010 and 2011 regarding interim TOU rates and the treatment of the one remaining customer?

Response

Hydro One is proposing to end the interim TOU rates at the same time as the 2010 distribution rates will be implemented and start charging the remaining customer on the interim TOU rate, the appropriate General Service demand billed rate.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #116 List 1

Interrogatory

Issue: #7.7

Reference: Exhibit G1/Tab 10/Schedule 1

a) Starting at page 3, line 13 the Application describes the treatment of losses for a number of specific situations. For each situation, please clarify whether the treatment described reflects current practice as approved by the Board or whether it describes a treatment that Hydro One Networks is proposing to apply starting in 2010. If the latter, please outline the current treatment of losses for the circumstance concerned.

Response

a) For each situation described, the treatment of losses reflects the current practice as approved by OEB in Proceeding EB-2007-681.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #117 List 1

Interrogatory

Issue: #7.1

Reference: Exhibit G2/Tab 1/Schedule 1, page 1 (lines 21-22) and Section 4.0

a) The description of the model changes implemented for this application differs from that included in EB-2007-0681. Please provide a schedule that lists all model changes that were implemented between EB-2007-0681 and the current Application.

Response

The following changes have been made to model between EB-2007-0681 and the current application and were documented in section 4 of Exhibit G2, Tab 1, Schedule 1:

4.0 MODEL CHANGES

Fixed Charge Floor Ceiling (Output Sheet 2)
Allocation of Miscellaneous Services Revenue (USoA 4235) has been divided into two sub accounts on row 181 and 182. This has been revised to allocate revenue in a manner similar to the allocation of associated costs.

Summary By Class and Accounts (Output Sheet 4)
An additional row has been added to reflect the new sub account 4235b.

Details By Class and Accounts (Output Sheet 5)
An additional row has been added to reflect the new sub account 4235b.

Categorization (Exhibit Sheet 1)
An additional row has been added to reflect the new sub account 4235b.

USoA 5340 categorization factor has been revised to allocate Miscellaneous Customer Accounts Expenses using O&M instead of using Weighted Number of Bills ("CWNB") as per OEB model.

Trial Balance Allocation Details (Exhibit Sheet 4)
An additional row has been added to reflect the new sub account 4235b.

Reconciliation (Exhibit Sheet 5)
An additional row has been added to reflect the new sub account 4235b.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #118 List 1

Interrogatory

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, page 10, lines 18-19
ii) Exhibit G2/Tab 1/Schedule 1, Sheet O1
iii) Exhibit E1/Tab 1/Schedule 2, pages 2-3

a) Using the originally filed version of Reference (iii) please show how the various categories of external revenues map into Row 89-95 of Sheet O1 in Reference (ii).

b) For each of the seven categories of External Revenue set out in Reference (ii) please describe the allocation factor used and explain why it was selected.

c) Based on the updated version of Reference (iii), please indicate how the external revenue assigned to each of the seven rows (Row 89-95) in reference O1 would change.

d) In the calculation of the Revenue to Cost Ratio based on the "unique" allocation of Miscellaneous Revenue (Sheet O1, Row 100), please explain why the value for Costs used in the denominator (O1, Row 97) is not the allocated Revenue Requirement (O1, Row 35) but is adjusted for the change in Miscellaneous Revenue allocation.

Response

a) The tables below show how the various categories of regulated and unregulated external revenue in Exhibit E1, Tab 1, Schedule 2, pages 2-3 have been mapped to Row 89-95 of Sheet 01 in Exhibit G2, Tab 1, Schedule 1, Sheet O1.

Table 1 - Regulated Revenues ($M)

$M	2010	Mapping
Joint Use	6.9	$6.7 million to Joint Use – Row 93 $0.2 million allocated to Other – Row 94
Sentinel Lights	3.3	$3.3 million to Sentinel Lights – Row 89
Retail Service Revenue	0.6	$0.6 million to Other – Row 94
Other Regulated Misc. Services	19.8	$14.1 million allocated to Late Payments – Row 90 $5.7 million allocated to other –Collections Row 57
Totals	30.6	

Table 2 - Unregulated Revenues ($M)

$M	2010	Mapping
Joint Use	3.5	$3 million to Joint Use $0.5 million to Other – Row 94
New Connects/Upgrades	3.0	$3.0 million to New connection and upgrades – Row 92
Generation Studies	3.2	$3.2 million to Other – Row 94
Other External Work	40.2	$40.2 million to Other – Row 94
Non-Regulated Misc. Rev.	1.7	$1.4 million to Other – Row 94 $0.3 million to Internal transfer
Totals	51.6	

b) The table below provides details on the allocation factor used for each category of External Revenue:

External Revenue	Allocator	Reason
Sentinel Lights	Directly allocated to Sentinel Light	Proper Allocation
Late Payments	Late Payment Historical Average	Best available information
Collections	# connections	Best available information
New Connects + Upgrades	# connections	Best available information
Joint Use	O&M	Generic
Other	1830 & 1835 D	Best available information as revenue in this class has been reclassified to USoA 5135. 1830 & 1835 D is the same allocator used for this account.

c) Based on the September 25, 2009 update to Exhibit E1, Tab 1, Schedule 2 only the External Revenue allocation to Row 94 would change from $46.1 million to $12.2 million. External Revenue assigned to all other rows would remain the same.

d) The Revenue Requirement is adjusted for the change in Miscellaneous Revenue allocation as this results in proper allocation of costs and revenue to each class. For example, 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.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #119 List 1

Interrogatory

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, pages 1-2
ii) EB-2007-0681, Exhibit H/Tab 12/Schedule 66

a) Please update the response to Reference (ii) – part (b).

b) Please re-do the density factor derivation (for both lines and transformers) but instead of just including the Residential, General Service – Energy and General Service – Demand in the analysis please include all of Hydro One Networks' customer classes.

Response

a) Density factors per rate class used in the current filing are given below:

	DxLines			Rtransf	
Rate Class	Customer	Demand		Customer	Demand
UR	0.17	0.17		0.55	0.58
R1	0.67	0.66		0.86	0.86
R2	1.70	1.48		1.34	1.21
Seasonal	1.00	1.00		1.00	1.00
GSe	1.09	1.14		1.05	1.08
GSd	1.11	1.15		1.07	1.07
UGe	0.20	0.17		0.56	0.51
UGd	0.32	0.27		0.59	0.65
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

b) Density factors including all rate classes are given below:

	DxLines			Rtransf	
	Customer	Demand		Customer	Demand
UR	0.15	0.32		0.54	1.12
R1	0.59	1.19		0.85	1.65
R2	1.51	2.68		1.32	2.33
Seasonal	1.12	2.94		1.01	2.74
GSe	1.20	1.82		1.12	1.79
GSd	2.98	1.16		1.38	1.24
UGe	0.22	0.26		0.60	0.84
UGd	0.86	0.27		0.76	0.76
Dgen	132.38	61.36		7.93	3.06
ST	71.97	0.17		7.03	0.07
St Lgt	1.00	1.00		1.00	1.00
Sen Lgt	1.00	1.00		1.00	1.00

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #120 List 1

Interrogatory

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, page 9
Ii) Exhibit G2/Tab 1/Schedule 1, Attachment 1

a) Reference (i) lists the various costs that Hydro One Networks states are directly allocated which total $7.797 M. However, in Reference (ii) (Sheet O1, Row 33) the costs directly allocated are reported as $7.948 M. Please reconcile.

b) Please confirm that Administration and General costs (excluding Property Insurance and Community and Safety Programs) are allocated to customer classes using the "O&M Allocator" as set out in Reference (ii) (Sheet O6, Row 173). If not, please indicate the Sheet and Row reference for the allocator used.

Response

a) The directly allocated costs sum up to a total of $7.948 M as shown in Exhibit G2 Tab 1, Schedule 1, Attachment 1. Numbers reported in Exhibit G2, Tab 1, Schedule 1, page 9 have been rounded to $0.1 M before being totaled resulting in the difference in the 2 values.

b) The Administrative and General Costs are allocated based on the default allocators per the Cost Allocation Model - E4 TB Allocation Details.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #121 List 1

Interrogatory

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, pages 17 & 19
ii) EB-2007-0681, Exhibit G2/Tab 1/Schedule 1, Attachment B

a) For conductors, the Minimum System Study assumes that all existing conductors are replaced by the "minimum system conductor" (Reference (ii), page 9). However, for purposes of determining the PLCC adjustment the Study assumed that each distribution station would supply a single feeder (page 12). Please reconcile this inconsistency.

b) Please indicate the actual number of feeders served by Hydro One Networks' distributing stations.

c) Please re-do the PLCC calculation (Reference (ii), page 13) using the actual number of feeders as opposed to assuming one feeder/distributing station.

d) Please re-do the cost allocation based on the PLCC calculations from part (c).

Response

a) The study being referenced in part (ii) was a study performed by an external consultant retained by Hydro One as part of Proceeding EB-2007-0681. The contract with that consultant was closed once the OEB issued its Decision on that Proceeding. To answer this question, Hydro One would have to issue a new Request for Proposal, select a consultant and have them respond to this question. his cannot be accomplished in the timeframe allowed for response to interrogatories.

b) The actual number of feeders served by Hydro One Networks' distribution stations is 2553.

c) Not Applicable, see response to part a).

d) Not Applicable, see response to part a).

Rogers Cable Communications Inc. INTERROGATORY #1 List 1

Interrogatory

[Reference: Ex. GI1T41S5] The evidence cites a fixed service charge for USL customers derived from the Cost Allocation Study of $27.80, being the sum of a starting fixed service charge of $33.95 and a derived USL credit of $6.15.

[Reference: Ex. GL1T41S2, p.2J The evidence cites a proposed fixed charge for the General Service Energy Billed customer class of $35.79.

(a) Please confirm the quantum of the fixed and variable charge components proposed for legacy general service energy billed customers for 2010.

(b) Please confirm that the variable charge for legacy USL customers is proposed to be the same as the variable charge for legacy GSe customers.

(c) Please reconcile the $33.95 fixed charge cited in the first referenced exhibit and the $35.79 fixed charge cited in the second referenced exhibit.

(d) Please document the derivation (i.e. component elements) of the proposed $6.15 USL fixed charge credit.

(e) In EB-2007-0681 the USL credit was derived as $6.86 [see Ex. G1/T4/S5 in that proceeding]. Please reconcile and explain the decrease in USL fixed charge credits from the EB-2007-0681 proceeding to the current proceeding.

Response

a) The fixed service charge for legacy general service energy billed customers is $33.62. The corresponding variable charge is 3.8 cents/kWh.

b) Yes, the variable charge for legacy USL customers is proposed at 3.8 cents/kWh the same as the variable charge for legacy GSe customers.

c) The fixed service charge of $33.95 for legacy GSe customers shown in Exhibit G1, Tab 4, Schedule 5 is composed of the fixed service charge of $33.62 plus USL meter charge of $0.33. The fixed service charge of $35.79 in Exhibit G1, Tab 4, Schedule 2 is the fixed service charge of $33.62 plus the smart meter charge of $2.17.

d) The USL fixed credit is derived from the cost allocation model. Further details on the component elements can be found in Exhibit G2, Tab 1, Schedule 1 Attachment 1, Tab O3.5 USL Metering Credit.

e) The USL credit has declined since the EB-2007-0681 proceeding for the following two reasons:

- USoA 5065 – Meter Expense has seen a significant reduction due to the mass deployment of Smart Meters for Residential and General Service Energy customers. As per OEB guideline, Smart Meter costs are being maintained in a separate Regulatory Asset Account.

- The mass deployment of Smart Meters has brought down the meter and meter related costs, changing the underlying meter capital costs and allocation to the General Service Energy class. Please refer to Exhibit G2, Tab 1, Schedule 1, Attachment 1, Tab 17.1 for further details.

Rogers Cable Communications Inc. INTERROGATORY #2 List 1

Interrogatory

[Reference: Ex. GI/T41S2, p.2 and GUT4/S5J The evidence proposes a fixed charge per account of $ 1.00 for street lights and sentinel lights, and a fixed charge of $27.80 per connection for USL customers (after application of the derived metering credit for USL customers).

(a) Please explain the difference between an account, as used in reference to street lights and sentinel lights, and a connection as used in reference to USL customers.

(b) Please explain the difference in distribution services provided to street lights and sentinel lights on the one hand, and to USL customers on the other, which explain the apparently significant difference in fixed charges.

Response

a) A Street Light or Sentinel Light account can have multiple connections, while USL is one account per connection.

b) The difference in the fixed charges for Street Light and Sentinel Light versus USL customers is due to the treatment of these classes in the cost allocation and rate design model. The difference can not be explained by differences or similarities in the distribution services provided.

Historically, Street Lights and Sentinel Lights have always been separate Rate classes in Hydro One as it is possible to more accurately estimate their consumption. In 2008, for the first time, these rate classes included a nominal fixed charge of $1.00. Prior to this, street light and sentinel light customers only paid volumetric rates.

Unmetered Scattered Load (USL) has historically been a sub-class of General Service class and hence the fixed rates are derived from the General Service Energy billed customer class. Hydro One Distribution received Board approval for the cost allocation and rate design treatment for USL in proceeding EB-2007-0681.

Rogers Cable Communications Inc. INTERROGATORY #3 List 1

Interrogatory

[Reference: Ex. Gl/T31SI] The referenced exhibit provides the revenue to cost ratios resulting from Hydro One's cost allocation study in support of this application.

(a) Please provide a revenue to cost ratio for legacy USL customers. Please provide all detail in support of the derivation of the ratio.

(b) If a precise revenue to cost ratio for legacy USL customers cannot be provided, please provide the basis for the requested approval for distribution charges proposed for USL customers in this application, and explain how the Board can conclude that the proposed USL charges are in accord with the directions provided in the Board's November 28, 2007 EB-2007-0667 report - Application of Cost Allocation for Electricity Distributors - at Page 9 regarding USL customers.

Response

a) To provide separate revenue to cost ratio for legacy USL customers, a substantial amount of effort and information that is not readily available, would be required to re-run the cost allocation. The effort would include making modifications to the OEB cost allocation model and developing load data for USL customers separately. This can not be accomplished within the Interrogatory response timelines.

b) The requested approval of the distribution charges proposed for USL customers is based on the review and approval of USL charges by the Board in proceeding EB 2007- 0681. Please see the OEB Decision with Reasons for proceeding EB 2007-0681, pages 26 - 28.

Consumers Council of Canada (CCC) INTERROGATORY #1 List 1

Interrogatory

GENERAL

Reference: Exhibit A/Tab 6/Schedule 1, page 1

The evidences states that the Application by HON Distribution is "substantially" consistent with the requirements of the 2006 EDR Handbook and with the Filing Requirements issued on November 14, 2009. Please specify where the application is not consistent with the documents noted above and explain why.

Response

Please refer to Exhibit H, Tab 7, Schedule 2.

Consumers Council of Canada (CCC) INTERROGATORY #2 List 1

Interrogatory

GENERAL

Reference: Exhibit A/Tab 14/Schedule 1, page 2

A part of the 20010-2014 planning cycle Business Plan instructions were issued in Quarter 1, 2009. Please provide a copy of those instructions.

Response

Please refer to Exhibit H, Tab 13, Schedule 1.

Consumers Council of Canada (CCC) INTERROGATORY #3 List 1

Interrogatory

GENERAL

Reference: Exhibit A/Tab 14/Schedule 1, page 4

Please provide a copy of the final investment plan, and any related material that was endorsed and confirmed by senior management that was prepared in 2009 and provided the basis for the 2010 and 2011 plans.

Response

As illustrated in Figure 1 of Exhibit A, Tab 14, Schedule 1, initial investment plan proposals are prepared as input into the prioritization and selection process. The capital and OM&A investments approved through this process comprise the investment plan component of Hydro One's business plan which can be found on pages 28-39 of the approved June, 2009 2010-2012 Corporate Business Plan filed in confidence in Exhibit H, Tab 13, Schedule 1 and in Exhibits C1 and C2 and D1 and D2.

Consumers Council of Canada (CCC) INTERROGATORY #4 List 1

Interrogatory

GENERAL

Reference: Exhibit A/Tab 14/Schedule 1, page 4-5

Please provide a copy of the financial plan and underlying assumptions provided to the HON Inc. Board of Directors in support of the 2010-2011 filing.

Response

Please refer to Exhibit H, Tab 13, Schedule 1

Consumers Council of Canada (CCC) INTERROGATORY #5 List 1

Interrogatory

LOAD AND REVENUE FORECASST

Reference: Exhibit E/Tab 2/Schedule 1, page 1

Please provide Board approved numbers for external revenues for the years 2006-2009.

Response

Board Approved amounts for external revenues for 2006 & 2008 are shown below. There are no Board Approved amounts for 2007 and 2009 as there were no Cost of Service applications for those years.

	2006	2008
Regulated Revenues		
Joint Use Revenue	**5.5**	**6.2**
Telecommunications		
	5.3	6.0
Street Lighting	0.3	0.2
Sentinel Revenue*	**3.6**	**4.0**
Retail Service Revenue	**N/A**	**1.1**
Miscellaneous Charges	**18.4**	**20.0**
Late Payment Charges	13.5	14.5
Other Miscellaneous Charges	4.9	5.5
Total Regulated	27.5	31.3
Unregulated Revenues		
Joint Use Revenue	**3.2**	**3.3**
Bell Canada	3.0	3.0
LDC's	0.2	0.3
DX Generation Studies	**0.1**	**0.5**
New Connects/Upgrades & Other Contestable Work	**8.1**	**6.2**
New Connects & Upgrades	5.0	4.0
Lines - Other Contestable Work	2.0	1.0
Forestry Contestable Work	0.1	0.1
Health, Safety & Environment Training	1.0	1.1
Non-Regulated Miscellaneous Revenue	**0.9**	**0.7**
Total Unregulated	12.3	10.7
Total External Revenue	**39.8**	**42.0**

1

Consumers Council of Canada (CCC) INTERROGATORY #6 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit A/Tab 8/Schedule 3, page 5

Please provide a schedule in the same format as Table 2 "Fees Payable to Networks for Services Provided" which includes the years 2006-2008.

Response

Fees Payable to Networks for Services Provided

FEES PAYABLE BY AFFILIATES TO NETWORKS FOR SERVICES TO BE PROVIDED BY NETWORKS: (in $Thousands)				
Services	**Hydro One Inc.**	**Remotes**	**Telecom**	**Brampton**
General Counsel and Secretary Services				
• **2006**	65	187	65	131
• **2007**	68	198	68	136
• **2008**	75	220	75	150
Financial Services				
• **2006**	29	230	370	457
• **2007**	112	201	389	240
• **2008**	57	308	354	236
Corporate Services				
• **2006**	0	56	92	18
• **2007**	0	79	106	45
• **2008**	0	89	146	28
Telecommunication Services				
• **2006**	0	163	286	0
• **2007**	0	126	202	0
• **2008**	0	118	195	0
Other Services				
• **2006**	0	547	1,033	0
• **2007**	0	481	920	0
• **2008**	0	479	1,086	0

FEES PAYABLE BY AFFILIATES TO NETWORKS FOR SERVICES TO BE PROVIDED BY NETWORKS: **(in $Thousands)**				
Services	**Hydro One Inc.**	**Remotes**	**Telecom**	**Brampton**
CEO/President Services				
• **2006**	0	80	0	0
• **2007**	0	80	0	0
• **2008**	0	80	0	0
Utility Operation Services				
• **2006**	0	725	0	0
• **2007**	0	325	0	0
• **2008**	0	325	0	0
Totals				
• **2006**	94	1,988	1,846	606
• **2007**	180	1,490	1,685	421
• **2008**	132	1,619	1,856	414

Consumers Council of Canada (CCC) INTERROGATORY #7 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit A/Tab 8/Schedule 3, page 7

Please provide a table in the same format as Table 3 that includes the years 2006-2008.

Response

Fees Payable by Networks for Services Received

FEES PAYABLE BY NETWORKS FOR SERVICES TO BE RECEIVED FROM HYDRO ONE INC AND TELECOM: (in $Thousands)			
Services provided by Hydro One Inc.	**2006**	**2007**	**2008**
General Counsel & Secretary	955	916	907
President / CEO / Chairman Services	4,242	4,080	3,366
Chief Financial Office Services	1,055	953	804
Totals	6,252	5,949	5,077
Services provided by Telecom			
Telecommunication Services	6,361	8,656	9,000
Totals	6,361	8,656	9,000

Consumers Council of Canada (CCC) INTERROGATORY #8 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 1, page 2

Please recast Table 1 including 2006-2008 Board approved numbers.

Response

Summary of Distribution OM&A Budget ($ Million)

Description	Historic (Actual)					Bridge	Test	
	2006	Board Approved 2006	2007	2008	Board Approved 2008	2009	2010	2011
Sustaining	250.8	230.3	272.6	284.5	270.3	296.4	318.5	340.5
Development	4.2	4.9	8.0	8.0	9.1	14.5	21.7	21.9
Operations	14.9	14.3	12.6	12.4	13.4	12.5	16.7	17.6
Customer Care	103.7	101.1	97.1	99.3	103.8	106.7	106.3	102.4
Shared Services and Other OM&A	21.2	67.9	91.8	62.9	65.2	92.4	92.1	88.1
Taxes Other Than Income Tax	4.5	4.6	4.2	4.3	4.5	4.6	4.7	4.8
Total	**399.3**	**423.1**	**486.2**	**471.3**	**466.3**	**527.1**	**560.0**	**575.2**

Consumers Council of Canada (CCC) INTERROGATORY #9 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 1, page 2

The evidence states that Increases in development expenditures are primarily attributed to the work required to integrate distributed generation and an increased focus on smart grid in response provided by the GEGEA. Please provide evidence to demonstrate that these expenditure are: a) related only to HON Distribution and not Transmission and b) that these expenditures are being undertaking for the sole benefit of HON Distribution customers.

Response

a) and b)

Hydro One understands the question to be referring to Development OM&A expenditures. The Development OM&A work is described in Exhibit C1, Tab 2, Schedule 3 which details the activities being undertaken and confirms that these expenditures are related only to Hydro One Distribution.

Development OM&A is a necessary component of a utility's program expenditures, and while the scope of this work is changing and expanding driven by the changing nature of the work required to serve the customers connected to the distribution system, Hydro One considers this work to be undertaken for the sole benefit of its customers.

Consumers Council of Canada (CCC) INTERROGATORY #10 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 1, page 3

Please recast Table 1 to include the Board approved numbers for the period 2006-2008.

Response

Please refer to Exhibit H, Tab 9, Schedule 8.

Consumers Council of Canada (CCC) INTERROGATORY #11 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 2, page 30

Please provide a complete breakdown of the $6.7 million and $6.9 million budgets for 2010 and 2011 for smart meter OM&A. Please provide a detailed explanation as to how these budget amounts were derived.

Response

Detailed breakdown is as follows:

Item	Derivation	2010 ($M)	2011 ($M)
Vendor maintenance fees (Trilliant, SmartSynch)	Forecast vendor fees based on the number of meters installed.	0.8	0.8
Bell/Rogers Fees for cell phones / backhaul	Forecast vendor fees based on the number of communicating devices.	0.6	0.7
Maintenance for AMCC, CMOM (Change Meter Order Management) paid to our sustainment service provider	Business IT maintenance costs for head end systems and Change Meter Order Management System	1.6	1.7
Billing System Maintenance	Maintenance costs for CIS associated with Smart Meters	0.6	0.6
Smart Meter and Network Operations Costs	Labour, materials and sundry costs associated with Smart Meter and Network Operations Department (monitor network for capturing reads and data for billing purposes sent to MDMR)	3.1	3.1
Total		6.7	6.9

These budget amounts relate to OM&A expenses forecast to be incurred in 2010 and 2011 for assets in service prior to 2009.

Consumers Council of Canada (CCC) INTERROGATORY #12 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 3, page 8

HON is proposing to spend $10 million per year on smart grid OM&A. Please provide a detailed explanation as to how the budgets were developed. Please indicate to what extent these expenditures have been subject to a business case analysis. If they have not been please explain why. Please explain in detail how HON chose the technologies its intends to pilot?

Response

HONI, and utilities globally, are faced with a number of new challenges. These include reacting to the paradigm shift from a few centrally located generators to large numbers of distributed generators, a rapid increase in conservation and demand management including in-home load control technologies, as well as new, potentially disruptive, technologies such as electric vehicles and plug-in hybrid electric vehicles. Ontario, through the GEGEA is taking a leadership role in these areas and there is a near term impact on HONI's distribution business.

Smart Grid OM&A spending is detailed in Exhibit H, Tab 9, Schedule 13 and includes R&D studies and Smart Zone spending. The specific studies will depend upon the response to the planned RFP described at Exhibit H, Tab 12, Schedule 46, as well as consultations with other industry stakeholders. In several areas, the R&D activities may be funded and jointly undertaken with Ontario Center of Excellence, Universities in Ontario and also with manufacturers. The R&D projects are expected to include utilization of renewable generation and storage technologies to reduce dependence on diesel in isolated areas of the distribution grid. Other projects being considered are DVAR, smoothing of power output from storage energy sources, plug in hybrid and charging systems etc.

Rather than being overly prescriptive in terms of detailed functional and technical requirements, Hydro One is looking to the market place to provide scalable solutions that cater to the radial distribution business and recognize the variety and type of enterprise applications in place today, as well as their associated business processes. Business cases will be developed as integrated solutions and technology are identified and completed after pilots have been undertaken.

Consumers Council of Canada (CCC) INTERROGATORY #13 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 3, page 8

Please identify all smart grid expenditures for 2010 and 2011 and explain how the specific technologies targeted were chosen. What is HON doing to ensure that: a) it is coordinating it smart grid activities with the Government and other LDCs and b) it is not piloting technologies that are being studied by others.

Response

The chosen technologies are based on business requirements. The business requirements are driven by the GEGEA.

The following table outlines Smart Grid Capital and OM&A costs for 2010 and 2011.

		2010	2011	References
Capital				
SG Related Operating Infrastructure				Exhibit D1/Tab 3/Sch 4 pp 3-8
	Distribution System Management	0.6	1.3	
	Real Time Feeder Analysis	0.3	1.2	
	Integrating Smart Meter Data in ORMS	1.6	2.1	
	ORMS Mobilt IT with CAD Integration	1.0	1.0	
	Geospatial Integration and Information Viewer	0.6	0.6	
	Network Operations Buildings Sustainment	2.4	2.3	
	ORMS Upgrade	0.2	1.5	
SG Related IT Development				Exhibit D1/Tab 3/Sch 6 p11
	Enterprise GIS Program	2.7	2.6	
SG Pilots and Studies				Exhibit D1/Tab 3 Sch 3 pp 22-24
	Energy Storage	1.9	1.8	

		2010	2011	References
	PHEV Trials	0.9	0.9	
	Distribution System Innovation	5.1	4.8	
Smart Zone Pilot				Exhibit D1/Tab 3/ SCh 3 pp22-24
	Equipment			
	Battery, Fuel Cell	1.0	1.0	
	Voltage Regulator / Cap Banks	0.0	1.0	
	Tie Points / Sectionalizers	0.0	1.0	
	Station RTUs	0.0	1.0	
System Integration		3.4	23.2	
Back Office Systems				
	Software	6.0	7.0	
	Other Hardware	0.0	4.0	
Other		2.4	4.2	
Total Capital		**30.1**	**62.5**	
OM&A				
Smart Grid Studies				Exhibit C1/Tab 2/Sch 3 pp3-8
	Energy Storage	1.4	1.4	
	PHEV Trials	0.9	0.9	
	DVAR Study	0.4	0.4	
	Other Studies	2.3	2.3	
Smart Zone Pilot				Exhibit C1/Tab 2/ Sch 3 pp6-8
	Business Process / Requirements	1.75	0.5	
	Communications	0.5	0.75	
	Data Model Design	0.75	1.5	
	Project Set-up	1.25	1.5	
	Other / Sundry	0.75	0.75	
Total OM&A		**10.0**	**10.0**	

a) and b) Please refer to the response at Exhibit H, Tab 7, Schedule 24 regarding Hydro One's collaboration and minimization of duplication of effort.

Consumers Council of Canada (CCC) INTERROGATORY #14 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 4, page 8

The 2010 and 2011 spending requirements for the Operations OM&A program are $12.4 and $12.8 respectively. The evidence indicates that the figures for 2010 and 2011 are greater than amounts in historic years as because of an increased focus on "distribution elements in alignment with distributed generation, smart meter and smart grid influences". If this is the case what elements of the Operations OM&A program are specifically related to these factors? Why are these expenditures not included in the Green Energy Plan?

Response

Please refer to Exhibit H, Tab 7, Schedule 56, parts a) and c)

Consumers Council of Canada (CCC) INTERROGATORY #15 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 4, page 9

The 2010 and 2011 spending requirements for Operating Support OM&A are $4.3 and $4.8 respectively. The evidence indicates that the amounts are greater than historic expenditures as a result of additional update and support tools associated with generation connections. If this is the case what elements of the Operating support budget are specifically related to the increase in generation connections? Why are these expenditures not included in the Green Energy Plan?

Response

All Operations functions will be impacted by Smart Grid and Distributed Generation influences. The existing processes and systems will be leveraged to the extent possible. The Outage Response Management System and the Network Management System will be expanded to capture generation connections. The Distribution Operating Diagrams and Station Operating Diagrams will be updated with the new connections and related system upgrades to provide accurate detailed information on the configuration of the distribution system to ensure the safe and reliable operation of the system. However these costs do not represent a major increase in historic Operating Support OM&A costs. Please refer to Exhibit H, Tab 7, Schedule 56, part c) with respect to the inclusion of these costs in the Green Energy Plan.

Consumers Council of Canada (CCC) INTERROGATORY #16 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 6, page 4

Of the Shared Services and Other OM&A Costs allocated to HON Distribution how much of that budget arises out of the implementation of the GEGEA? Please explain how HON allocates Shared Services and Other OM&A costs related to the implementation of the GEGEA to Transmission and Distribution.

Response

While Hydro One recognizes that work related to the Green Energy Plan is contributing to an increase in costs as described in the evidence, Shared Services costs have not been broken out between "green plan" vs "non-green plan" spending. Shared Services costs, which include support costs for GEGEA initiatives, are allocated to Distribution consistent with the B&V cost allocation methodology.

Consumers Council of Canada (CCC) INTERROGATORY #17 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 7, page 4

The evidence states that increases in the Corporate Management Function in 2010 and 2011 are mainly due to additional work requirements driven by the GEGEA. Please explain how the GEGEA impacts these costs.

Response

Please refer to response at Exhibit H, Tab 7, Schedule 58, part b).

Consumers Council of Canada (CCC) INTERROGATORY #18 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 7, page 5

The evidence states that the Outsourcing Services and Enablement were included in Finance in 2008 at a combined total cost of $4.5 million. Please recast Table 3 by removing the Outsourcing and Enablement Costs for the years 2006-2008. In addition, please provide the Board approved levels for each of those years.

Response

Please refer to response at Exhibit H, Tab 10, Schedule 35 (b) for a recasting of Finance costs for 2006-2008.

The table below shows the Board approved levels for 2006-2008:

$M	**2006**	**2007**	**2008**
Finance	26.5[1]	25.0[2]	26.9[3]

[1] EB-2005-0378
[2] EB-2006-0501
[3] EB-2007-0681

Consumers Council of Canada (CCC) INTERROGATORY #19 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 7, page 8

HON's Insurance costs are increasing significantly in the period 2009-2011. Are these part of the overall Finance Function budget ? Please explain, in detail, why the costs are increasing so significantly. Please explain what HON has done to attempt to mitigate these cost increases.

Response

Certain insurance premiums and costs are included as part of the Finance Function, as described in Exhibit C1, Tab 2, Schedule 7 page 7 lines 19 through to 24. The cost for other insurance premiums are charged to work programs or are included as an Asset Management cost as described in Exhibit C1, Tab 2, Schedule 7 page 8 lines 7 and 8. The increase in the insurance program costs is discussed in the Exhibit H, Tab 1, Schedule 40.

Consumers Council of Canada (CCC) INTERROGATORY #20 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 7, page 12

Please provide a detailed budget for all elements of the Corporate Communications Function. In addition, please recast Table 6 to include Board approved numbers.

Response

The attached table below provides the functions that comprise Corporate Communications and Services as well as the Board approved amounts for 2006-2008 (in $ millions):

Function	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
First Nations & Métis Relations	-	-	0.3	1.5	3.4	3.5
Communications	6.4	5.8	5.7	5.5	5.6	5.7
Outsourcing Services	-	-	-	2.6	3.5	3.2
Corporate Communications and Services	**6.4**	**5.8**	**6.1**	**9.6**	**12.5**	**12.4**

Board Approved Amounts	**2006**	**2007**	**2008**
Corporate Communications and Services	6.3[1]	5.5[2]	5.7[3]

[1] EB-2005-0378
[2] EB-2006-0501
[3] EB-2007-0681

Consumers Council of Canada (CCC) INTERROGATORY #21 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 7, page 16

Please provide a detailed budget for all elements of the General Counsel and Secretary Function. Please provide explain how the budget was derived, including all assumptions. In addition, please explain how the budget is impacted by the GEGEA.

Response

Attached in the table below is the composition of the budget for General Counsel and Secretary for 2010 and 2011 (in $ millions):

Function	**2010**	**2011**
Corporate Secretariat	1.7	1.7
Law Division	7.3	7.5
Total	**9.0**	**9.2**

The budget for General Counsel and Secretary budget comprises both labour and non-labour costs. Labour costs include all salaries and benefits payable to Hydro One staff. Non-labour expenses comprise external counsel and consultant fees and contractor expenses. Budgets are developed using approved assumptions for labour escalation and benefit cost rates. Total costs are expected to be higher in 2010 and 2011 compared to 2009 as a result of higher anticipated overall legal costs which includes planned support for matters related to the GEGEA.

Consumers Council of Canada (CCC) INTERROGATORY #22 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 8, page 3

Asset Management Function costs are increasing substantially in the period 2009-2011. The evidence states that the "largest influence" on the 2010 and 2011 capital and OM&A plan has been the introduction of the GEGEA. Please explain how the Asset Management Function relates to HON Distribution's Green Energy Plan. If costs within the Asset Management Function are increasing because of the GEGEA why are they not part of the Green Energy Plan. If those costs are being incurred in order to benefit Ontario more broadly then why are those costs specific to the GEGEA being recovered through the Global Adjustment Mechanism?

Response

The Asset Management function provides support to both the transmission and distribution work programs, based on the demands and the requirements of the capital and OM&A work programs including the initiatives of the Green Energy Act.

The increases in Asset Management costs between 2009 to 2011, are not exclusively driven by the initiatives of the Green Energy Act, but also support other areas of the capital and OMA work programs e.g. the increased efforts to replace end-of-life assets across the transmission and distribution systems. The ongoing and increased activities of the Asset Management function are described in Exhibit C1, Tab 2, Schedule 8.

Work driven by the Green Energy Plan has increased OM&A spending in a number of areas but Hydro One considers this to be an increase in the scope of work of its normal day-to-day activities necessary to address the changing nature of the investments required to service the customers connected to its system, and therefore believes it is appropriately recovered through its distribution rates.

Consumers Council of Canada (CCC) INTERROGATORY #23 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 8, page 5

Please indicate what portion of the Strategy and Business Development budget is related to LDC merger and acquisitions for each year 2008-20011.

Response

Approximately $700,000 was related to distribution rationalization, policy and regulatory matters pertaining to service area amendments and our relationships with LDCs. We did not forecast any significant expenditure for LDC merger and acquisitions in 2010 and 2011 and due to the closure of the transfer tax exemption window at the end of October 2009.

Consumers Council of Canada (CCC) INTERROGATORY #24 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 8, page 16

Please provide a detailed budget for all elements of the Real Estate and Facilities Function . In addition, please recast Table 7 to include Board approved numbers. Please explain, in detail, why this component of the Shared Services - Asset Management budget is increasing so significantly.

Response

	Historic Actuals			**Bridge**	**Test (Budget)**		*Allocation to Distribution*	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2010**	**2011**
Total Costs	38.7	37.5	41.9	48.1	57.8	59.9	28.7	29.7
Real Estate	6.6	6.4	7.0	8.5	8.6	8.8	1.6	1.6
Facilities	32.1	31.1	34.9	39.6	49.2	51.1	27.1	28.1
Board Approved	41.2	39.8	40.5	46.5	49.1			

Facilities costs are largely driven by company work programs and factors such as corporate staff levels, changing business and operating requirements and fixed cost contractual obligations. Also, the current regulatory environment (including health and safety requirements) ultimately impacts operating costs. Accommodation needs are influenced by the development and growth of Company work programs and initiatives, such as Distributed Generation and the Green Energy Act. The Facilities work program includes all aspects of company work space requirements which includes not only company-owned facilities, but management of the portfolio of leased facilities and oversight of the construction of new facilities.

Hydro One estimates that additional OM&A funding of approximately $3.0M in 2010, and $4.0M in 2011, will be required to meet current head office and GTA space requirements. This figure includes $2.0M in 2010 and $3.0M in 2011 to secure leased administrative office space within the GTA. The additional space is largely prompted by staffing needs generated by program growth associated with the Green Energy Act. The funding required also includes one-time costs resulting from new head office lease accommodation of $2.6M in both years 2010 and 2011 which covers the costs of employee moves and provides for temporary “swing space” for staff to allow for necessary tenant improvements.

Existing field facilities space is fully utilized and cannot accommodate additional staff. Additional accommodation needs of lines of business are examined in terms of short and long term needs, logistics and geographic proximity to service areas, work sites and corresponding acceptable accommodation alternatives available. The local real estate markets in the field offer limited or no leasing opportunities readily available that can accommodate Hydro One business requirements. The need for additional space in the field is being addressed now mainly by utilizing temporary trailers and/or modular buildings. Hydro One currently estimates minimum of $3.4M in both years 2010 and 2011 in additional OM&A funding required for field facilities are as result of anticipated increase in work activities mainly due to the Green Energy Act. It is assumed that the field staff growth will be accommodated by utilizing leased modular office buildings on short term bases.

The Real Estate work program includes acquisition activities, development work, management of real estate rights associated with distribution lands and stations, corridor leasing and other property-related activities.

Our assessment of space needs continues, in cooperation with the respective business units, and will clarify (as better information become available) the requirements associated with the increasing work program, especially the requirements resulting from the implementation of the Green Energy Act, the modernization of distribution systems and connecting distributed generation.

Consumers Council of Canada (CCC) INTERROGATORY #25 List 1

Interrogatory

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Reference: Exhibit C1/Tab 2/Schedule 9, page 20

Please provide a detailed budget for all elements of the IT Management & Project Control Expenditures. Please explain, in detail, why this component of Shared Services - Asset Management budget is increasing so significantly.

Response

Table 6
IT Management & Project Control Expenditures
($ Millions)

Description	Historic			Bridge	Test		DX Allocation	
	2006	2007	2008	2009	2010	2011	2010	2011
IT Management(a)	4.2	5.6	4.4	12.0	18.1	19.5	8.0	8.7
Project Support and Control(b)	0.8	1.1	3.1	4.4	5.8	5.4	3.3	3.0
Total	**5.0**	**6.7**	**7.5**	**16.4**	**23.9**	**24.9**	**11.3**	**11.7**

The IT management (a) budget for 2010 is $18.1M:

- $17.0M for labour costs to manage, plan and govern the extensive IT infrastructure, software applications, outsourced services
- $1.1M for non labour costs (eg: training, conferences, business expenses)

This portion (a) of the budget has increased a total of $13.7M from $4.4M in 2008 to $18.1M in 2010 because of the other departments and associated budgets being transferred to the IT organization. Please see response at Exhibit H, Tab 1, Schedule 51.

Additional cost increases due to the following (+$1.3M impact):

- $0.4M in 2009 for management of outsourced services as it approaches end of term, support of SAP architecture and overall program management
- $0.9M in 2010 for ongoing management and support of business warehouse (BI/BW) reporting tools delivered with Cornerstone Phase 2 $0.5M and allowance for escalation in labour & benefit cost for all staff $0.4M

The Project Support and Control (b) budget for 2010 is $5.8M:

Group	Item	$M
Architecture, Security and Standards	• Architectural development and updates to technology roadmap and standards for data/voice telecommunication convergence, infrastructure (desktop and servers), applications [$0.4M] • Security governance updates for compliance to NERC CIP and security standards and procedures updates. [$0.2M] • Research on the establishment of enterprise security monitoring and operations centre [$0.8M] • Assessment on improvement opportunities in IT security control measures for access control / email monitoring, network segregation, vulnerability assessment, audit compliance services [$0.6M] • Assessment on desktop and server technology upgrade in the Microsoft operating systems and productivity tool suite [$0.3M] • Development and update of strategy on data management policy with respect to enterprise content management program for both structured and unstructured data sets [$0.3M]	2.6
Infrastructure/ Application Technology Updates	• Decommissioning of legacy systems that were replaced by new systems [$0.3M] • Enhancement and deployment of user self service technology tools (Service Centre Wizard) [$0.1M] • Certified licensed software for Inergi support personnel who provide services to Hydro One as part of the outsourced contractual arrangement. [$0.3M] • Provisioning peripherals (memory device, laptop batteries, hard drives, portable printers, adaptors) to support business operations [$0.8M] • Refresh of internal portal intranet/extranet technology [$0.6M]	2.1
Training	• User Education for new and upgraded end user productivity and technology tools such as Microsoft Office 2007/10 as part of Windows 7 rollout. [$0.3M] • Provide security and awareness training [$0.1M]	0.4
PCO	• Overall Project Management and Project Control Office (PCO)	0.7
	Total	5.8

Consumers Council of Canada (CCC) INTERROGATORY #26 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 1/Schedule 3, page 1

Please recast Table 1 - In-service Capital Additions 2008-2011 to include 2008-2006 actuals and the 2009 6+6 budget.

Response

Please refer to the following table:

	2006 Actual	2007 Actual	2008 Actual	2009 Forecast	2010 Test Yr	2011 Test Yr
Sustaining	155.2	132.9	154.0	171.3	175.8	195.5
Development	142.5	155.8	134.4	165.6	186.8	230.9
Operations	0.0	5.7	0.4	0.0	6.8	9.0
Other	82.1	122.1	212.7	108.7	177.9	112.0
Total	379.9	416.5	501.6	445.5	547.2	547.4

Consumers Council of Canada (CCC) INTERROGATORY #27 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 1/Schedule 3, page 1 and Exhibit D1/Tab 3/Schedule 1 page 2

Please reconcile Table 1 at D1/T1/S3 and Table 1 at D1/Te/S1/p. 2. In addition, please explain the footnote which states, "Development Capital costs of $62.4 million in 2010 and $129.1 million in 2011 for renewable generation connection enhancements are subsequently deducted under Shared Services & Other Capital". Does this reflect the amounts assumed to be collected through the Global Adjustment Mechanism? Why is the adjustment made to Shared Services & Other Capital?

Response

Table 1 in Exhibit D1, Table 1, Schedule 3, represents the In-Service Capital Additions (ISA) for the historical year 2008, bridge year 2009 and test years 2010 and 2011 whereas, Table 1 in Exhibit D1, Table 3, Schedule 1, represents Capital Expenditures for the historical, bridge and test years.

The capital expenditures represent the amounts that were spent in the historic years as well as the amounts that we are proposing to spend in the bridge and test years on the distribution capital work program whereas, the In-Service Capital Additions represents the actual and planned capitalized amounts from the distribution capital work program in each of the historic, bridge and test years.

The foot-note which states, "Development Capital costs of $62.4 million in 2010 and $129.1 million in 2011 for renewable generation connection enhancements are subsequently deducted under Shared Services & Other Capital", was removed in the revised exhibits filed on September 25, 2009 with the Board. The September 25, 2009 update included revising the evidence to more clearly portray the gross and net capital spending related to generation connection enhancements. The assumed recovery of capital costs via an external funding mechanism is now netted out of the Generation Connection Enhancements line as shown on Table D1 of Exhibit 1, Tab 3, Schedule 3. This eliminated the need to deduct the externally funded amounts from Shared Services & Other Capital.

Consumers Council of Canada (CCC) INTERROGATORY #28 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 2 page 14

Please explain the extent to which t he implementation of smart meters will impact the budget for Trouble Call and Storm Damage Response in 2010 and 2011. Is the new technology expected to reduce costs in terms of identifying the location of outages? Has that been incorporated into the budget? If so, how?

Response

As described in Section 3.3 of Exhibit D1, Tab 3, Schedule 4 and Exhibit D2, Tab 2, Schedule 3, ISD# O3, Hydro One Distribution is planning to integrate the information from Smart Meters into the Outage Response Management System. This project is scheduled for 2010 and 2011 and should be operational in 2012. Consequently, reductions in costs for Trouble Call and Storm damage are not expected to materialize until beyond 2011. The expected amount of these reductions has not been quantified at this time.

Consumers Council of Canada (CCC) INTERROGATORY #29 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 3 page 2

Please recast Table 1 "Summary of Net Development Capital to include 2006-2008 Board approved numbers. Please recast Table 1 to set out the entire budget without any adjustments for cost recovery through generators or the Global Adjustment Mechanism. In effect, please set out the Total Development Capital net of any adjustments.

Response

Description	Historic					Bridge	Test	
	2006	Board Approved 2006	2007	2008	Board Approved 2008	2009	2010	2011
Connections, Upgrades and Cancellations	104.6	90.6	105.9	101.8	103.9	98.0	113.5	115.4
System Capability Reinforcement	29.7	36.3	36.9	36.7	44.0	41.4	47.0	50.9
GROSS** Generation Connections	1.9	N/A*	2.7	8.5	N/A*	15.1	106.0	167.1
GROSS** Generation Connection Enhancements	0	0	0	0	0	0	62.4	129.1
Wholesale Revenue Meters	11.1	9.0	9.7	10.8	11.4	7.7	7.9	2.8
Smart Grid	0	0	0	0	0	15.2	20.8	49.9
TOTAL	147.3	135.9	155.2	157.8	159.3	177.4	357.6	515.2

* Only “net” numbers were filed and approved by the OEB.
** Includes Capital Contribution from generator and Capital costs recovered via External Funding.

Consumers Council of Canada (CCC) INTERROGATORY #30 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 3 page 10

The evidence states that forecasting the actual number and type of generation connections is challenging. Please describe in detail the process HON has been using to develop the forecast. How does HON decide the cost of connections, and the costs of the related investments? How has HON decided what level of those investments will be recovered from the generators?

Response

The forecast for the number and approximate size of generation connections is based on consideration of the historic number of generation connections and the other factors listed on page 8 of Hydro One Distribution's Green Energy Plan.

The cost of the generation connections is based on the historical cost of similar investments, while the cost for generation connection enhancements is largely based on an estimate of the Distribution Station upgrades and new feeders likely to be required to accommodate the forecasted volume new renewable generation connections.

The forecast for the level of investments that will be recovered from generators is based on the 3 categories of costs defined in the proposed amendments to the Distribution System Code (i.e. Connection Costs, Expansion Costs, and Renewable Enabling Improvement costs) and the historical breakdown of these costs for a typical project.

Consumers Council of Canada (CCC) INTERROGATORY #31 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 3 page 10-15

HON has included costs in its application for its Generation Connection Program. HON has also excluded costs either directly funded by generators or costs that it expects to be funded by an external funding mechanism. The Council would like some clarification regarding the accounting treatment of these expenditures. Please explain the following:

1. How has HON identified "investments that enable and promote the growth of renewable generation and are expected to provide significant benefits to all of Ontario's electricity customers"?
2. With respect to the expenditures that will be funded through an external funding mechanism, what if HON's actual costs are greater or less than forecast? Will there be a mechanism for a true-up? If not, why not? If so, how would such a mechanism be used?
3. Will the funds received through the external funding mechanism be treated as "contributed capital"? If not, why not?
4. If expenditures are funded through the external funding mechanism how will HON's rate base be impacted?
5. For those expenditures funded through the external funding mechanism, please confirm that they will be expensed rather than capitalized.

Response

1) Hydro One's methodology for allocating Generation Connection related Capital costs between External Funding Mechanism (i.e. all of Ontario's electricity customers) and Hydro One Distribution Rates (Hydro One customers) are discussed in Section 3.0 of Hydro One's Green Energy Plan (Exhibit A, Tab 14, Schedule 2) filed with the Board September 25th, 2009.

2) Hydro One considers its forecasts appropriate. Hydro One expects to recover the actual costs of these investments and anticipate that any mechanism related to the true-up of costs to be collected via the external funding mechanism will be addressed as part of the implementation of OReg 330/09.

3) The funds received through the external funding mechanism will not be treated as contributed capital in accordance with OReg 330/09 which allows for the recovery of costs associated with making eligible investments, as defined in the Distribution

System Code. The funds collected via the external funding mechanism will be applied to draw down the revenue requirement accrual account associated with the Green Energy Plan.

4) There will be no impact on the Distribution rate base as these costs and associated funding will be tracked separately from the rate base costs recovered through Hydro One's distribution rates.

5) Expenditures funded through the external funding mechanism will be capitalized but not included in Hydro One Distribution's rate base to be recovered through distribution rates.

Consumers Council of Canada (CCC) INTERROGATORY #32 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 3 page 15

HON has presented a forecast for its 2010 and 2011 Generation Connection Enhancements Program Costs. What are the implications for HON if those forecasts turn out to be too high or too low given the uncertainty around the number and type of investments? Does HON consider these forecasts to be conservative? If they are conservative will HON seek relief in any way during the test years? If so what type of relief is anticipated?

Response

Hydro One Distribution considers these forecasts appropriate and therefore does not expect the program costs to deviate much from the forecast. If it turns out the forecast is too high or too low during the test years, Hydro One has no plans to seek relief during the test years. As with all investments in its Application, Hydro One Distribution accepts the risks associated with variances from Board-approved levels.

Consumers Council of Canada (CCC) INTERROGATORY #33 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 3 page 15

Please provide a table which sets out the following:

1. Forecast of all Generation Connection Costs for 2010 and 2011 (capital and OM&A);
2. Forecast of those costs expected to be funded by generators;
3. Forecast of those costs to be funded by an external funding mechanism;
4. Forecasts of those costs to be recovered through rates.

Response

Summary of Net Development Capital Costs

$ Millions	**Total Capital Costs**		**Generator Funded Costs**		**Externally Funded Costs**		**Net Capital Costs**	
	2010	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**	**2011**
Generation Connections	106.0	167.1	13.3	26.8	83.6	125.5	9.1	14.8
Generation Connection Enhancements	62.4	129.1	0	0	55.0	110.5	7.4	18.6
Total	**168.4**	**296.2**	**13.3**	**26.8**	**138.6**	**236.0**	**16.5**	**33.4**

As stated in Exhibit A, Tab 14, Schedule 2, the on-going OM&A costs associated with maintaining the portion of Expansion and REI capital investments that will be externally funded are assumed to be negligible over the test year period. However, if in the future these OM&A costs are determined to have increased to material levels, Hydro One Distribution will seek approval to include them as part of the revenue requirement to be externally funded.

Consumers Council of Canada (CCC) INTERROGATORY #34 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 3 page 21

Please provide a detailed description of the Plug-in Hybrid Electric Vehicles field trial. Please provide all costs associated with this program, both capital and operating costs.

Response

The Plug-in Hybrid Electric Vehicles (PHEVs) field trial is part of Hydro One's RFP described in Exhibit H, Tab 12, Schedule 46. The advent of PHEVs will cause utilities to not only address infrastructure modifications but also to potentially widen its relationship with its customer base. Solutions addressing this scenario will focus on the impact of PHEVs on:

1. Fleet Management
   a) Lowering overall carbon footprint.
   b) Using less fuel.
   c) Reducing noise pollution.

2. Enablement of consumers to use PHEVs via:
   a) In-home load prioritization and management.
   b) 3rd party contractor engagement.
   c) ESA certification.
   d) Utility notification of intent to purchase so the utility can manage load / infrastructure impact.

3. Utility Network Impact
   a) Both rural and urban system impacts due to PHEV proliferation.
   b) Customer transformer / DS / TS system modifications requirements.
   c) Phase balancing.
   d) Vehicle to grid (V2G) power quality implications.

Specific costs associated with PHEV trials will be determined once the RFP response has been received and solutions related to PHEV's have been evaluated. Some funds, totaling $0.9M in each of 2010 and 2011, have been budgeted in anticipation of expenditures in this area.

Consumers Council of Canada (CCC) INTERROGATORY #35 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 3 page 21

HON has identified cost of $12.5 million for 2010 and $42.8 million for 2011 for its Owen Sound Zone Pilot. Provide a detailed breakdown of those budgets.

Response

The Smart Zone costs were typed incorrectly in Exhibit D1, Tab 3, Schedule 3 page 21. They should have been $12.8 and $42.4 million.

The activities and expenditures within the Owen Sound Smart Zone are included as part of an RFP described in Exhibit H, Tab 12, Schedule 46.

A breakdown of Smart Zone capital costs is provided in Exhibit H, Tab 9, Schedule 13.

The response to the RFP will drive the specifics of what will be installed and tested. Recognizing that Hydro One is looking for the RFP respondents to provide their vision for an innovative and integrated solution, the cost breakdown in Exhibit H, Tab 9, Schedule 13 is a preliminary forecast of what might occur, not intended to limit RFP respondents in any way. The forecast was done on an overall basis using estimates gleaned from vendors, experts and internal staff based largely on similar previous installations and other utilities and clients. With completion of the RFP, the referenced costs will be refined and a detailed breakdown of cost will then be available.

The initial scope of equipment included in the cost table is further broken down in Schedule 1 below. This is intended to provide respondents with sufficient scope to test solutions.

System integration activity referenced in the cost table primarily refer to the integration of back office software (e.g. Distribution Management System, GIS, OMS, Operational Data Store (ODS) and other enterprise applications), new applications (ODS), and related information technology and business process design and development services.

Schedule 1 - Anticipated Scope of Work Summary for Owen Sound Smart Zone

Station / DS	Nomenclature	Station Print	Equipment Type	Description of Work
Owen Sound	M23-M24	Owen Sound TS - M23/M24 Feeder Tie	Disconnect Switch	Smart Switch SCADA enabled
	M25-M26	Owen Sound TS - M25/M26 Feeder Tie	Disconnect Switch	Smart Switch SCADA enabled
Holland RS	Holland Centre RS	Owen Sound TS - M26	Regulator Station	Smart Regulating Station SCADA enabled
	CHAP-SB1	Owen Sound TS - M26	Load Interrupter Switch (Center Break)	Smart Recloser SCADA enabled
	A-M26	Owen Sound TS - M26	Load Interrupter Switch (Center Break)	Smart Recloser SCADA enabled
	WIA-1	Owen Sound TS - M23	Load Interrupter Switch (Center Break)	Smart Recloser SCADA enabled
	WIA1-WIA2	Owen Sound TS - M23/M24	Load Interrupter Switch (Center Break)	Smart Recloser SCADA enabled
	WIA-2	Owen Sound TS - M24	Load Interrupter Switch (Center Break)	Smart Recloser SCADA enabled
	M24R	Owen Sound TS - M24	Electronic Recloser	Smart Recloser Scada enabled - Retro-fit if possible
	HEP-3	Owen Sound TS - M25	Load Interrupter Switch (Center Break)	Smart Switch SCADA enabled
	DER-1	Owen Sound TS - M25	Load Interrupter Switch (Center Break)	Smart Switch SCADA enabled
	DER-3	Owen Sount TS - M25	Recloser	Smart Recloser SCADA enabled - Retro-fit if possible
Chatsworth DS		Owen Sound M26	Station	Smart DS (Equipment and Protection & Control)
	REC 62	Chatsworth F2	100 amp Oil Filled Recloser L type A1B3	Smart Recloser SCADA enabled
	Capacitor	Chatsworth F2	currently not installed	Smart Capacitor SCADA enabled
	REG 495	Chatsworth F2	3 X 150 amp regulators	Smart Grid control, bi-directional, SCADA enabled
Berkley DS		Owen Sound M26	Station	Smart DS (Equipment and Protection & Control)
	REC 1816	Berkley F2	100 amp Oil Filled Recloser 4H type A2B2	Smart Recloser SCADA enabled
	SW 833	Tie between Berkley F2 & Chatsworth F2	3 Phase In-line - solid blades	Smart Recloser SCADA enabled
6th St East DS	F1	Owen Sound M22	ITE Breaker - Ganged	Smart Recloser SCADA enabled
2nd Ave. East DS	F4	Owen Sound M28	ITE Breaker - Ganged	Smart Recloser SCADA enabled
	D-6SE-3A	Mid Feeder Switch between 6th & 2nd	3 Phase In-line - solid blades	Smart Recloser SCADA enabled
	D-6SE-W7A	F1 feeder 6th St. East DS	3 Phase In-line - solid blades	Smart Recloser SCADA enabled
Meaford	M1VR	Meaford TS - M1	Electronic Recloser	Smart Recloser SCADA enabled - Retro-fit if possible
	M1-M2	Meaford TS - M1/M2 Feeder Tie	Disconnect Switch	Smart Switch SCADA enabled
	1M1	Meaford TS - M1, Eugenia GS	High Voltage Interrupting Device (HVI)	New Transfer Trip to 1M1 breaker SCADA enabled
	"New" Capacitor	Meaford TS - M1, ROC-3		Smart Capacitor SCADA enabled
	56M1-2	Meaford TS - M1	Disconnect Switch	Smart Recloser SCADA enabled
	56M1-1	Meaford TS - M1, 56M1-1		Monitoring Device SCADA enabled
	Eugenia RS	Meaford TS - M1	Regulator Station	Smart Regulating Station SCADA enabled

Consumers Council of Canada (CCC) INTERROGATORY #36 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 4 page 3

The Operations Capital Budget is increasing from $.9 million in 2008 to $2.4 million in 2009 and $8.1 million in 2010. The 2011 budget increases further to $11.2 million. The justification provided in the evidence is that the Ontario government's GEGEA is having a major impact on distribution operations. If this is the case why are not some or all of these expenditures being funded through an external funding mechanism?

Response

The Operations Capital spending attributable to the Ontario government's GEGEA is included in the as part of the Smart Grid spending shown in the Green Energy Plan, as described on page 29 of Exhibit A, Tab 14, Schedule 2. These investments will provide significant benefits to Hydro One Distribution customers for the future enablement of the Smart Grid, and therefore it is appropriate to include these costs in the rate base for recovery from Hydro One's customers.

Consumers Council of Canada (CCC) INTERROGATORY #37 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 4 page 2

The evidence refers to the smart meter program and its impact on Operations. Please indicate for 2010 and 2011 all of the expected costs and benefits associated with the smart meter program and the impact of those on the 2010 and 2011 Operations Capital budgets. Why has the implementation of the smart meter program created a need to increase the Operations Capital budget?

Response

In order to benefit from the functionality provided by Hydro One's Smart Meters Distribution Operating must design and develop an interface to receive and interpret the relevant Smart Meter data in the Outage Response Management System (ORMS). The operations capital plan has allocated funds in the amounts of $1.8M in 2010 and $1.2M in 2011 for this improvement to ORMS. The expected benefits of the Smart Meter information in ORMS include improved outage management by automatically detecting outages and locating affected equipment to allow for faster restoration of service to Hydro One's customers.

Consumers Council of Canada (CCC) INTERROGATORY #38 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 6 page 1

With respect to IT capital please provide a schedule setting out each of the programs and expenditures planned for 2010 and 2011 and prioritize those projects in terms of need. In effect ,which programs are the most urgent and which programs could potentially be deferred? For each program please set out the specific costs.

Response

The following tables describe the IT Capital program for 2010 and 2011 and their costs. IT investments are made in accordance with approved business strategies and follow the IT governance process that takes into consideration business need and resource availability when setting priority of projects. All of the identified projects are the result of review during the planning process and are deemed necessary.

IT Capital Expenditures for 2010			
Group	**Item**	**$M**	**Priority**
Enterprise Application Software	o Enterprise Content Management system implementation and integration with enterprise applications.	1.3	1
Operating Systems	o Life-cycle refresh of user Desktop operating systems, Email Exchange, Productivity tools and associated enterprise applications	2.7	1
Utility Software	o Life-cycle upgrade of Oracle database management systems across enterprise to replace unsupported versions o Upgrade of enterprise information integration middleware to address application dependency	1.7	1

IT Capital Expenditures for 2010			
Group	**Item**	**$M**	**Priority**
	requirements and to enhance disaster recovery readiness. o Implementation and refresh of infrastructure utility tools for enhanced capacity and performance management for Database management (Oracle Grid)		
System and Security Tools	o Application security and performance monitoring tools o Life-cycle upgrade of anti-virus protection software o Backup and restoration	2.8	1
Network Equipment/Security	o Security programs for central authentication, network segregation, security status and audit monitoring, centralized logging. o Life cycle refresh of end of life voice systems, branch office router upgrades, network bandwidth expansion o Telecom Disaster/Recovery expansion	6.0	1
PBX/Voice Mail	o Refresh of end of life PBX and Voice Mail systems	2.0	1
PC and Printer Hardware	o Lifecycle refresh of desktops, laptops, tablets, handhelds, printers, plotters	6.3	1
Servers Refresh	o Lifecycle refresh of Unix and Windows servers	3.3	1
Enterprise Reporting Refresh	o Hardware and software refresh	0.5	1
Mainframe Refresh	o Lifecycle refresh of mainframe	2.0	1
Development Programs	o Mobile IT	3.0	1

IT Capital Expenditures for 2010			
Group	**Item**	**$M**	**Priority**
Development Programs	o Warehouse Bar Coding	1.0	1
Development Programs	o Enterprise GIS Program	6.0	1
Development Programs	o DX Asset Information System	0.4	1
	Total $(M)	39.0	

IT Capital Expenditures for 2010			
Group	**Item**	**$M**	**Priority**

IT Capital Expenditures for 2011			
Group	**Item**	**$M**	**Priority**
Enterprise Application Software	o Continuation of implementation of Enterprise Content Management program	2.8	1
Operating Systems	o Continuation of Life-cycle refresh of user Desktop operating systems, Email Exchange, Productivity tools and associated enterprise applications	2.4	1
Utility Software	o Implementation of Information Life cycle/rights management technology o Refresh of middleware infrastructure software (enterprise service bus) o Continue Upgrade of enterprise information integration middleware	1.7	1
System and Security Tools	o Refresh/Upgrade DMZ	2.0	1

IT Capital Expenditures for 2010				
Group	**Item**		**$M**	**Priority**
	(Demilitarize zone) for network security access control protection o Refresh of anti-spamming tools for email / virus protection			
Network Equipment/Security	o Security Operations Centre implementation o Security programs for central authentication, network segregation, security status and audit monitoring, centralized logging. o Life cycle refresh and upgrade of end of life voice systems, branch office router upgrades, network upgrades to facilitate increase of bandwidth and LAN wireless expansion. o Continuation of Telecom Disaster	5.8	1	

IT Capital Expenditures for 2010				
Group	**Item**		**$M**	**Priority**
	recovery			
PBX/Voice Mail	o Continuation of Refresh of end of life PBX and Voice Mail	1.7	1	
PC and Printer Hardware	o Lifecycle refresh of desktops, laptops, tablets, handhelds, printers, plotters	6.1	1	
Servers Refresh	o Lifecycle refresh of Unix and Windows servers	3.2	1	
Development Programs	o Mobile IT – continuation from 2010	2.9	1	
Development Programs	o Enterprise GIS Program	5.9	1	
	Total $ (M)	34.5		

1

Consumers Council of Canada (CCC) INTERROGATORY #39 List 1

Interrogatory

CAPITAL EXPENDITURES AND RATE BASE

Reference: Exhibit D1/Tab 3/Schedule 7

Please indicate whether or not Phase 2 of the Cornerstone project - Replacing PeopleSoft Finance/Human Resources/Payroll Functionality has been put into service. If not, what is the expected in-service date?

Response

Yes.

Consumers Council of Canada (CCC) INTERROGATORY #40 List 1

Interrogatory

CAPITAL STRUCTURE AND COST OF CAPITAL

Please provide a schedule setting out HON Distribution's approved ROE and actual ROE for the years 2006-2008.

Response

The Board allowed ROE per year is as follows:

2006	9.00%
2007	9.00%
2008	8.57%

As per Exhibit A, Tab 9, Schedule 1, Attachment 1, Attachment 2, Attachment 3 and using a CGAAP approach, actual ROE for Hydro One Distribution is as follows:

2006	8.42%
2007	5.78%
2008	7.11%

Consumers Council of Canada (CCC) INTERROGATORY #41 List 1

Interrogatory

CAPITAL STRUCTURE AND COST OF CAPITAL

Reference: Exhibit A/Tab 2/Schedule 1, page 2

The evidence states that the resulting distribution rate increase for the average customer relative to 2009 rates will be approximately 9% in 2010 and 13% in 2010. Please provide the full range of rate impacts for residential customers. Please provide the same information regarding the range of bill impacts.

Response

The following table provides the range of rate impacts (distribution rates with riders and total bill) for residential customers in 2010 and 2011.

	2010	2011
Distribution Rates	2% to 40%	12% to 29%
Total Bill Impact	-1% to 9%	4% to 10%

Consumers Council of Canada (CCC) INTERROGATORY #42 List 1

Interrogatory

CAPITAL STRUCTURE AND COST OF CAPITAL

Reference: Exhibit A/Tab 2/Schedule 1, page 2

In calculating its bill impacts for residential customers has HON considered the fact that although certain costs are being excluded from its revenue requirement, the Global Adjustment Mechanism is likely to increase accordingly? If not why not?

Response

In determining bill impacts resulting from a utility revenue requirement application, OEB Guidelines are that all other costs, that are beyond the distributors control, are to remain constant, e.g. commodity, Wholesale Market Service Charges. Additionally, Hydro One has no information on the potential increase in the Global Adjustment Mechanism.

Consumers Council of Canada (CCC) INTERROGATORY #43 List 1

Interrogatory

SMART METERS

Reference: Exhibit F1/Tab 1/Schedule 3, page 1

Please provide one schedule setting out the total expenditures, by year, both capital and operating, that have been spent on the smart meter program since its inception. This will include, but not be limited to:

1. Total metering cost s - both capital and operating costs
2. Total network costs (AMRC and WAN)
3. Total AMCC costs
4. Total costs related to MDM/R
5. Costs of any pilots
6. Cost for customer communication and education
7. Costs for incremental functionality
8. Any other costs considered part of the smart metering program

In the same format, please provide the forecast costs for 2010 and 2011. In addition, please provide a schedule setting out the annual recovery of smart meter costs from HON's customers to date.

Response

OM&A Smart Meter Costs

$ Thousands		2006 ACTUAL	2007 ACTUAL	2008 Actual	2009 Forecast	2010 Forecast	2011 Forecast
OM&A Cost for Minimum Functionality							
2.1	Advanced Metering Communication Device (AMCD)	1,005	1,626	2,662	2,334	4,491	3,228
2.2	Advanced Metering Regional Collector (AMRC and WAN)	1	843	647	1,067	1,172	3,433
2.3	Advanced Metering Control Computer (AMCC)	24	765	80	2,608	3,401	3,440
2.5	Other AMI OM&A Costs Related to Minimum Functionality	3,711	2,979	3,555	8,606	5,278	4,888
	OM&A Cost for Minimum Functionality	4,741	6,212	6,945	14,616	14,343	14,989
OM&A Cost for Exceeding Minimum Functionality		163	0	0	84	7,769	7,356
	OM& A Sub Total	4,904	6,212	6,945	14,700	22,112	22,345
	LESS CDM Funding	881					
	Total OMA	4,023	6,212	6,945	14,700	22,112	22,345

Capital - Smart Meter Costs

$ Thousands		2006 ACTUAL	2007 ACTUAL	2008 Actual	2009 Forecast	2010 Forecast	2011 Forecast
Capital Costs for Minimum Functionality							
1.1	Advanced Metering Communication Devices (AMCD)	9,984	51,494	69,691	65,941	57,677	13,812
1.2	Advanced Metering Regional Collector (AMRC and WAN)	0	5,074	4,699	35,993	15,638	1,161
1.3	Advanced Metering Control Computer (AMCC)	950	3,944	1,632	2,144	0	1,506
1.4	Other AMI Capital Costs Related To Minimum Functionality	879	4,459	4,253	21,149	3,700	2,488
	Sub Total Capital Cost for Minimum Functionality	11,813	64,971	80,275	125,227	77,016	18,968
	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	9,411	5,307	2,156	316
	Collector Outage Detection Capability	0	403	3,970	3,366	990	102
	Wimax	968	0	0			13,540
	TOU Capability	1,035	4,639	9,141	10,421	5,646	0
	Integration and Transaction Management	70	3,780	3,440	22,390	17,318	11,400
	Total Costs for Functions Exceeding Minimum Functionality	2,255	12,534	25,962	41,483	26,110	25,358
	TOTAL SMART METER COSTS	7,667	77,505	106,237	166,710	103,125	44,326

Annual recovery of smart meter costs from HON's customer to date is provided in the table below.

Annual Recovery Smart Meter Costs	$Million
2006	2.5
2007	10.0
2008	13.2
2009 (Jan. to June 2009)	7.5

Consumers Council of Canada (CCC) INTERROGATORY #44 List 1

Interrogatory

GREEN ENERGY PLAN

Reference: Exhibit A/Tab 12/Schedule 1

Please provide copies of all materials presented to HON's Board of Directors setting out the potential implications for HON regarding the Green Energy and Economy Act and related OEB Codes (RSC, DSC).

Response

This information is filed in confidence with the Board and will be made available to intervenors that sign a Declaration and Undertaking form in accordance with the OEB Practice Direction on Confidential Filing.

Consumers Council of Canada (CCC) INTERROGATORY #45 List 1

Interrogatory

GREEN ENERGY PLAN

Reference: Exhibit A/Tab 14/Schedule 2

Has HON, at any point in 2007, 2008 or 2009, provided information or advice to the Minister of Energy, the Ontario Power Authority, or the Ontario Energy Board with respect to the reliability of renewable energy sources or the economic viability of renewable energy sources? If so, please provide copies of that information or advice.

Response

Hydro One Networks is in the business of transmitting and distributing electricity in Ontario. We do not have a corporate position on the sources of generation used by the province. As such, Hydro One Networks did not provide information or advice to the Minister of Energy, the Ontario Power Authority, or the Ontario Energy Board with respect to the reliability of renewable energy source or the economic viability of renewable energy sources.

Consumers Council of Canada (CCC) INTERROGATORY #46 List 1

Interrogatory

GREEN ENERGY PLAN

Reference: Exhibit A/Tab 14/Schedule 2 page 1

In light of the passage of Ontario Regulation 330/09 please explain how HON intends to specifically identify each of the investments that "directly benefit" its customers. Please explain how the table on p.1 would be amended, if at all, now that the regulation has been passed.

Response

An update of Exhibit A, Tab14, Schedule 2 (the Green Energy Plan) was filed with the OEB on September 25, 2009. The assumptions used in the updated Green Energy Plan, and the costs summarized in the table on page 1, are consistent with the requirements of Ontario Regulation 330/09.

The update describes the criteria Hydro One Distribution has applied to specifically identify the investments that "directly benefit" its customers.

Consumers Council of Canada (CCC) INTERROGATORY #47 List 1

Interrogatory

GREEN ENERGY PLAN

Reference: Exhibit A/Tab 14/Schedule 2 page 1

In the update provided on September 25 the table on page 1 has changed from that provided in the initial evidence. Please specifically identify why the renewable generation capital costs have changed for each year from the initial filing. Please include all assumptions.

Response

The capital costs in the table on page 1 changed as part of the September 25 Update to include $31M in work associated with renewable generation that was previously categorized as Line-contestable work for others and included in the evidence provided at Exhibit C1, Tab 2, Schedule 11. This change was required to align with the proposed amendments to the Distribution System Code issued by the Board on September 11, 2009.

Consumers Council of Canada (CCC) INTERROGATORY #48 List 1

Interrogatory

GREEN ENERGY PLAN

Reference: Exhibit A/Tab 14/Schedule 2 page 6

Please explain how the costs of the Connection Impact Assessments and the costs related to connection cost estimates and completion of connection cost recovery agreements are recovered and for 2007, 2008 and 2009 please provide the OM&A costs incurred by HON in processing the CIA requests and recovery agreements. What are the proposed budgets for 2010 and 2011?

Response

The costs of the Connection Impact Assessments (CIAs) are recovered through charges for the CIAs, for which the generators pay when they apply for CIAs. The costs associated with processing CIAs are detailed in development of the associated service charges in Exhibit G, Tab 93, Schedule 1. The costs of estimates are recovered through charges for the Connection Cost Estimate (CCE) reports, for which the generators pay when they apply for CCEs. All the connection costs for each generator have historically been paid for by the generator when they apply for their Connection Cost Recovery Agreement (CCRA). The CCRA costs are not recovered from generators, as the staff working on CCRA's do their work on many different CCRA's at a time and it would be difficult to track their work by each separate CCRA individually.

The forecast budget for completing generation studies is included in the Other Cost of Sales figures of $1.7 million in each of 2010 and 2011 as discussed in Exhibit C, Tab 2, Schedule 11.

The CIA and CCE costs are recovered directly from generators, and this practice will continue.

Consumers Council of Canada (CCC) INTERROGATORY #49 List 1

Interrogatory

GREEN ENERGY PLAN

Reference: Exhibit A/Tab 14/Schedule 2 page 10

HON states that "the objectives of Hydro One set for the (Green Energy) Plan… align with Hydro One's corporate strategy".

What elements, if any, of Hydro One's Green Energy Plan existed prior to January 1, 2009?

Response

Prior to January 1, 2009 the elements of Hydro One's Green Energy Plan that existed and were considerations in the development of Hydro One's corporate strategy include a focus on the need to connect large numbers of new distributed generators in response to the RESOP program and the large number of CIA applications submitted to the Company, a continued focus on conservation and demand management, and a need to evolve the automation of our distribution system to better leverage the Smart Meters installed and to improve service to our customers.

The Green Energy related investment activities that advance these key initiatives are put forth in Hydro One's Application and summarized in its Green Energy Plan as required under the *Green Energy and Green Economy Act, 2009* and by the Board in their Guidelines for Deemed Conditions of Licence Regarding Distribution System Planning.

School Energy Coalition (SEC) INTERROGATORY #1 List 1

Interrogatory

GENERAL

Reference: Exhibit A/Tab 14/Schedule 5

Has the 'Investment Plan' referred to in the evidence been filed? If not, please provide a copy.

Response

Please refer to Exhibit H, Tab 9, Schedule 3 and Exhibit H, Tab 13, Schedule 1.

School Energy Coalition (SEC) INTERROGATORY #2 List 1

Interrogatory

Cost of Capital

Reference: Exhibit B1/Tab 2/Schedule 1, Page 7

the 2010 and 2011 debt rate forecasts are based on the forecast Canada bond yield (plus applicable HON spread), which in turn is based on the April 2009 Consensus Forecasts. Please update the Canada bond forecast and resulting HON yield.

Response

Please refer to Exhibit H, Tab 3, Schedule 27.

School Energy Coalition (SEC) INTERROGATORY #3 List 1

Interrogatory

Cost of Capital

Reference: Exhibit B2/Tab 1/Schedule 2, Page 5

please provide the actual cost rate for the two 2009 debt issuances (lines 25, 26 and 27 of B2-1-2, p. 5- projected rates for these issues are 6.03%, 4.77% and 4.77% respectively).

Response

Please refer to Exhibit H, Tab 3, Schedule 29.

School Energy Coalition (SEC) INTERROGATORY #4 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2

With respect to the external funding mechanism to be established pursuant to Ontario Regulation 330/09, the Board on September 25 announced a consultation process (EB-2009-0349) to arrive at a way of determining the direct benefits that accrue to the consumers of a licensed distributor as a result of an eligible investment. Given that:

(a) please explain how HON has determined the amount to be collected via external funding ($8 and $30.7 million respectively in 2010 and 2011).

(b) Does HON plan on amending its application and/or 2010/2011 revenue requirement in the event its Plan does not conform to the Board's decision in EB-2009-0349?

Response

a) The amounts of $8.0 M and $30.7M are the revenue requirement associated with the portion of capital expenditures that are determined not to provide benefits to Hydro One Distribution customers based on applying the criteria defined in Section 3.3 of the Green Energy Plan. Details of the calculation are provided at Exhibit H, Tab 1, Schedule 151.

b) Hydro One Distribution will follow the Board’s direction on this issue and address any changes required to the approvals requested in its Application as part of the draft Rate Order to be submitted in this case.

School Energy Coalition (SEC) INTERROGATORY #5 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 7, line 22-23

please explain the purpose of the update to this portion of the evidence, which changed from "3,500 MW of renewable generation *will be* connected by 2011 and an additional 3,500MW *will be* connected by 2014" to "3,500MW of renewable energy generation *could seek connection* by 2011 and an additional 3,500 MW *could seek connection* by 2014, given technical feasibility."

Response

The changes were made to more accurately portray the expectations with respect to the level of renewable generation connections anticipated. As discussed on pages 12-13 of the Green Energy Plan filed at Exhibit A, Tab14, Schedule 2, the forecast of the amount of renewable generation is largely based on historical RESOP/CIA applications and existing system constraints. There is some uncertainty about the number and types of generators that will seek connection, as well as when and what areas of the Transmission system will get reinforced. Hydro One did not want to imply an unwarranted level of precision about the total MW that “will be” connected given the potential Transmission limitations in popular areas to persist, and for generators to show up differently than was observed by the historical CIA applications).

School Energy Coalition (SEC) INTERROGATORY #6 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 8

Please provide a summary of the number, size and location of the connection requests received thus far.

Response

Attachment 1 shows a summary of the number, size and location of the connection requests received for the Hydro One Distribution system before any requests to rescind CIAs were received.

Hydro One Distribution Generation Connections Application List

The following is a list of projects for which Hydro One has received complete applications for Connection Impact Assessments (CIAs) as of August 31st, 200
(Please contact GCD Coordinator (gcd.coordinator@HydroOne.com) immediately if any information pertaining to your project has been incorrectly posted or if you require confirmation of your project ID number)

NOTE: In order to view this document properly, please print on legal size paper in colour.

- **Supply Stations are listed in alphabetical orde**
- **The acceptable generation (reverse flow limit) is based on equipment limitations and consideration of minimum load at the supply station proposed for connection and is subject to the findings of a CIA for each individual project**
- **The acceptable generation is based on the maximum feeder loading limit of 400A and consideration of the minimum load on the feeder**
- **As CIAs are processed, other equipment limitations maybe identified which may limit the amount of generation that can connect at a given supply station. If your status is listed as 'CIA Pending', Hydro One recommends that proponents wait until the CIA is complete and a queue position has been assigned to the project before moving forward.**
- **Different stations have different configurations and hence appropriate limits apply**
- **All projects listed at distribution stations (DS) (excluding High Voltage Distribution Stations) will also be listed, by date of application, on the upstream transmission station (TS)/HVDS. This reflects the fact that projects connecting to DSs also impact the capacity at the upstream TS**
- **The first project below the red line shown for each station may be able to proceed for connection at a reduced capacity, subject to the findings of a CI**
- **All CIAs being reworked for uprating are being done per OEB mandate**
- **Project ID numbers are not representative of the order in which Hydro One processes applications**
- **Station capacity is not guaranteed if small projects appear at a later dat**
- **Hydro One has changed the tool for tracking projects and this change has resulted in Hydro One assigning new ID numbers to some projects at this time. The listing for the affected projects includes both the Old and the New ID numbers in the following format: NEW ID NUMBER (OLD ID NUMBER - SIZE)**

LEGEND	
TECHNICAL CONSTRAINT	**SYMBOL**
60 (%) REVERSE FLOW	(%)
400 AMP LIMIT	(A)
SHORT CIRCUIT THRESHOLD	(SC)

Addison DS	
Acceptable Generation = 3.4 MW	
Station Queue Position	**F2**
CIA Ineligible	1805 (0.498 MW)

Project 1805 has applied to connect to Brockville TS

Agimak HVDS
Total acceptable generation on feeders F1, F2 = 7 MW
Currently there is no Application received on this Station

Agincourt TS
Total acceptable generation on feeders M2, M4, M6, M8, M10, M12 = 15 MW
Total acceptable generation on feeders M1, M3, M5, M7, M11 = 14 MW
Cumulative Generation on station cannot exceed 30 MW
Currently there is no Application received on this Station

***Aguasabon HVDS**		
Acceptable generation on T3 = 0.8 MW		
Acceptable generation on T2 = 0.6 MW		
	T2	**T3**
Station Queue Position	**F1 (%)**	
CIA Ineligible	564 (9 MW)	

*Equipment beyond the Hydro One supply station is owned by third parties hence there can be no reverse flow through the station.
This limits the amount of generation that can connect to this station.

Albion TS
Acceptable generation on transformer winding BQ ("BQ") = 23 MW
Acceptable generation on transformer winding JY ("JY") = 15 MW
Cumulative Generation on BQ & JY cannot exceed 39 MW
Currently there is no Application received on this Station

Alexander DS		
Acceptable generation on T1 = 11.9 MW		
Acceptable generation on T2 = 13.1 MW		
Cumulative generation on T1 & T2 cannot exceed 16 MW		
	T1	**T2**
Station Queue Position	**F1 - (%)**	
1	217 (6.4 MW)	
2	10370 (1834 - 5.5 MW)	
CIA Ineligible	1891 (9 MW)	

Project 217 has applied to connect to Southmarch TS

Project 1891 has applied to connect to Southmarch TS

Project 10370 has applied to connect to Southmarch TS

Allanburg TS		
Total acceptable generation on Feeders M6, M7, M8 = 22 MW		
Station Queue Position	**M8 - (%)**	**M6 - (%)**
1	586 (10 MW)	
2	10610 (1889 - 9 MW)	
CIA Ineligible		1985 (10 MW)

Alliston TS						
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6 = 70 MW						
Station Queue Position	M6 - (A)	M3 - (%)	M2 - (%)	M4 - (%)	M1 - (%)	M5 - (%)
1				2179 (10 MW)		
2					2178 (9 MW)	
3		541 (10 MW)				
4	1320 (10 MW)					
5	1528 (10 MW)					
6		1529 (10 MW)				
7	1830 (10 MW)					
CIA Ineligible	1831 (10 MW)					
CIA Ineligible		1833 (10 MW)				
CIA Ineligible		1978 (10 MW)				
CIA Ineligible		1979 (10 MW)				
CIA Ineligible			1980 (10 MW)			
CIA Ineligible			1981 (10 MW)			
CIA Ineligible			1982 (10 MW)			
CIA Ineligible			2019 (10 MW)			
CIA Ineligible					2029 (10 MW)	
CIA Ineligible				2030 (10 MW)		
CIA Ineligible						2079 (10 MW)
CIA Ineligible		2102 (10 MW)				

Almonte TS		
Total acceptable generation on feeders M25 = 25.9 MW		
Total acceptable generation on feeders M26, M28 = 31.6 MW		
Cumulative Generation on station cannot exceed 32.7 MW		
	T3	T4
Station Queue Position	M25 - (%)	M28 - (%)
1	63 (5 MW)	
2		1309 (10 MW)
3	1497 (9.99 MW)	
4	10460 (1498 -7.659 MW)	
CIA Ineligible	1568 (10 MW)	
CIA Ineligible	1569 (10 MW)	
CIA Ineligible		1880 (9 MW)
CIA Ineligible	1911 (9.99 MW)	

Ardoch HVDS
Total acceptable generation on feeders F1, F2 = 6 MW
Currently there is no Application received on this Station

Armitage TS DESN 1 (T1 & T2)		
Total acceptable generation on feeders M11, M12, M13, M14, M21, M22, M 23, M24 = 119 MW		
Station Queue	M22	
1	1426 (10 MW)	
2	1427 (10 MW)	
3	1842 (10 MW)	

Armitage TS DESN 2 (T3 & T4)		
Total acceptable generation on feeders M31, M32, M33, M34, M41, M42, M43, M44 = 86 MW		
Station Queue Position	M43	M32
1	1076 (1.5 MW)	
2		1845 (10 MW)
3		1846 (10 MW)

Arnprior TS		
Total acceptable generation on feeders M1, M2 = 34 MW		
Station Queue Position	M2 - (%)	M1- (%)
1	1208 (10 MW)	
2	1209 (10 MW)	
3		1210 (10 MW)
CIA Ineligible		1216 (10 MW)
CIA Ineligible	1882 (9 MW)	
CIA Ineligible		1883 (9 MW)

Aylmer TS	
Total acceptable generation on feeders M1, M2 = 12 MW	
Station Queue Position	M2 - (%)
1	561 (0.85 MW)
2	2098 (10 MW)

Azilda DS	
Acceptable Generation = 4.6 MW	
Station Queue Position	F1
Queue Exempt	2171 (0.190 MW)

Project 2171 has applied to connect to Clarabelle TS

Barrie TS
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7 = 68 MW
Currently there is no Application received on this Station

Basin TS
Acceptable generation on bus A5A6 = 11 MW
Acceptable generation on bus A7A8 = 10 MW
Cumulative Generation on station cannot exceed 23 MW
For any information or inquiries please contact Toronto Hydro

Bath DS	
Acceptable Generation = 3.9 MW	
Station Queue Position	TBD - (%)
CIA Ineligible	1523 (10 MW)

Project 1523 has applied to connect to Napanee TS

Bathurst TS DESN1 (T1&T2)
Total acceptable generation on feeders M10, M4, M5, M6, M8 = 11 MW
Total acceptable generation on feeders M1, M2, M3, M7, M9 = 12 MW
Cumulative Generation on station cannot exceed 19 MW
For any information or inquiries please contact Toronto Hydro

Bathurst TS DESN2 (T3&T4)
Total acceptable generation on feeders M23, M25, M27, M31 = 13 MW
Total acceptable generation on feeders M24, M26, M30, M32 = 6 MW
Cumulative Generation on station cannot exceed 20 MW
For any information or inquiries please contact Toronto Hydro

Battersea HVDS		
Total acceptable generation on feeders F1, F2 = 7 MW		
Total acceptable generation on feeders F3 = 7 MW		
Cumulative generation on station cannot exceed 8 MW		
	T1	T2
Station Queue Position	F1 - (%)	
1	1054 (0.498 MW)	
CIA Ineligible	1916 (7.5 MW)	
CIA Ineligible	1925 (8.5 MW)	

Beach TS DESN1
Total acceptable generation on feeders M71,M72,M73,M74,M81,M82,M83,M84 = 7 MW
Total acceptable generation on feeders M41,M42,M43, M44, M31,M32,M33,M34 = 8 MW
Cumulative Generation on station cannot exceed 18 MW
For any information or inquiries please contact Horizon Utilities Corporation

Beach TS DESN2
Total acceptable generation on feeders M11, M12, M13, M14, M21, M22, M23, M24 = 0 MW
Total acceptable generation on feeders M51,M52,M53,M54,M61,M62,M63,M64 = 7 MW
Cumulative Generation on station cannot exceed 9 MW
For any information or inquiries please contact Horizon Utilities Corporation

Beachburg DS	
Acceptable Generation = 4 MW	
Station Queue Position	F2
Queue Exempt	1257 (0.1 MW)
1	819 (0.5 MW)

Project 819 has applied to connect to Cobden TS

Project 1257 has applied to connect to Cobden TS

Beamsville TS		
Total acceptable generation on feeders M1, M2, M3, M4 = 33 MW		
Station Queue Position	M1	M2 - (%)
1		2167 (10 MW)
2	2168 (10 MW)	
3		2022 (10 MW)

Beardmore HVDS #2		
Total acceptable generation on feeder F1,F2,F3,F4 = 7 MW		
Station Queue Position	TBD - (%)	F2
CIA Ineligible	168 (10 MW)	
1		1946 (6 MW)

Beaverton TS						
Total acceptable generation on feeders M23, M24, M25, M26, M27, M28, M29, M30 = 89 MW						
Station Queue Position	M27 - (%)	M23	M26 - (%)	M24 - (%)	M30	M29 - (%)
Queue Exempt	1668 (0.10 MW)					
1	379 (10 MW)					
2	380 (10 MW)					
3				381 (9.9 MW)		
4			382 (10 MW)			
5			383 (10 MW)			
6		431 (9 MW)				
7		432 (9 MW)				
8		433 (9 MW)				
9					434 (9 MW)	
CIA Ineligible			492 (10 MW)			
CIA Ineligible	713 (10 MW)					
CIA Ineligible	968 (10 MW)					
CIA Ineligible						1838 (10 MW)
CIA Ineligible						1881 (9 MW)
CIA Ineligible				10110 (2 MW)		
CIA Ineligible				10140 (2.5 MW)		

Project 1668 has applied to connect to Port Bolster DS

Belle River TS			
Total acceptable generation on feeders M1, M2, M3, M4 = 31.2 MW			
Station Queue Position	M2 - (A)	M4 - (%)	M1
Queue Exempt			1682 (0.5 MW)
1	8 (10 MW)		
2	556 (9.9 MW)		
CIA Ineligible	870 (10 MW)		
CIA Ineligible	626 (10 MW)		
CIA Ineligible	628 (2 MW)		
CIA Ineligible	1009 (10 MW)		
3		994 (10 MW)	
CIA Ineligible	1157 (10 MW)		
CIA Ineligible		2068 (10MW)	

Belleville TS				
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8, M9 = 121 MW				
Station Queue Position	M5	M6	M2	M7 - (SC)
1	837 (0.498 MW)			
2		782 (10 MW)		
3		1034 (10 MW)		
4			1471 (10 MW)	
5			1472 (10 MW)	
6	1473 (10 MW)			
7	1474 (10 MW)			
8				1475 (10 MW)
9				1476 (10 MW)
CIA Ineligible		1558 (9.9 MW)		
CIA Ineligible		1559 (9.9 MW)		
CIA Ineligible			1564 (10 MW)	
CIA Ineligible			1565 (10 MW)	
CIA Ineligible			1566 (10 MW)	
CIA Ineligible			1567 (10 MW)	
CIA Ineligible	1839 (10 MW)			
CIA Ineligible				1840 (10 MW)
CIA Ineligible				1841 (10 MW)
CIA Ineligible			1885 (9 MW)	
CIA Ineligible		2024 (10 MW)		
CIA Ineligible			2130 (9 MW)	
CIA Ineligible				10130 (2206 - 6.8 MW)

Project 837 has applied to connect to Stirling DS

Bermondsey TS DESN1
Total acceptable generation on feeders M23,M25,M27 = 0 MW
Total acceptable generation on feeders M24,M26,M28 = 5 MW
Cumulative Generation on station cannot exceed 6 MW
Currently there is no Application received on this Station

Bermondsey TS DESN2
Total acceptable generation on feeders M1,M3,M5,M7,M9,M11 = 12 MW
Total acceptable generation on feeders M2,M4,M6,M8,M10,M12 = 22 MW
Cumulative Generation on station cannot exceed 34 MW
Currently there is no Application received on this Station

Bilberry Creek TS
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6 = 61 MW
Currently there is no Application received on this Station

Birmingham TS DESN1 (T1&T2)
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6,M7,M8 = 3 MW
Total acceptable generation on feeders M21,M22 = 2 MW
Cumulative Generation on station cannot exceed 5 MW
Currently there is no Application received on this Station

Birmingham TS DESN2 (T3&T4)
Total acceptable generation on feeders M10,M11,M12,M13,M14 = 3 MW
Total acceptable generation on feeders M71,M81 = 23 MW
Cumulative Generation on station cannot exceed 23 MW
Currently there is no Application received on this Station

Birr DS		
Acceptable Generation = 3.7 MW		
Station Queue Position	F2	F3
1	363 (0.3 MW)	

Project 363 has applied to connect to Clarke TS

Bracebridge TS
Acceptable Generation on feeder M20 = 40 MW
Currently there is no Application received on this Station

Bramalea TS DESN1 (T1&T2)
Total acceptable generation on feeders M2,M4,M6,M8,M10,M12 = 16 MW
Total acceptable generation on feeders M1,M3,M5,M7,M9,M11 = 11 MW
Cumulative Generation on station cannot exceed 27 MW
Currently there is no Application received on this Station

Brant TS			
Acceptable Generation M11, M12, M13, M14, M21, M22, M23, M24 = 61 MW			
Station Queue Position	M21 - (A)	M22	M14
1	1951 (9.9 MW)		
2		1973 (10 MW)	
3		2028 (10 MW)	
4	1983 (10 MW)		
5			2083 (10 MW)
CIA Ineligible	2097 (10 MW)		
CIA Ineligible	2152 (10 MW)		

Brantford TS			
Total acceptable generation on feeders M22,M24,M26,M28,M30 = 16MW			
Total acceptable generation on feeders M21,M23,M25,M27,M29 = 23MW			
Cumulative Generation on station cannot exceed 40 MW			
	Z	Y	
Station Queue Position	M26	M27	
1	1123 (8.1 MW)		
CIA pending		10560 (1941 - 9 MW)	

Brockville Schofield DS	
Acceptable Generation = 2.1 MW	
Station Queue Position	F41
Queue Exempt	1402 (0.09 MW)

Project 1402 has applied to connect to Brockville TS

Brockville TS					
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, B1R = 58 MW					
Station Queue Position	B1R - (A)	M2 - (%)	M6 - (%)	M5 - (A)	M3 - (%)
Queue Exempt					1402 (0.09 MW)
1		1334 (10 MW)			
2			1315 (9.9 MW)		
3			1395 (10 MW)		
4			1396 (10 MW)		
5		1416 (10 MW)			
CIA Ineligible		1417 (10 MW)			
CIA Ineligible		1570 (9.9 MW)			
CIA Ineligible		1457 (0.499 MW)			
CIA Ineligible		1644 (10 MW)			
CIA Ineligible			1805 (0.498 MW)		
CIA Ineligible					1836 (10 MW)
CIA Ineligible			1884 (9 MW)		

Project 1402 has applied to connect to Brockville Schofield DS

Project 1805 has applied to connect to Addison DS

Project 1457 has applied to connect to Lyn DS

Bronte TS DESN1
Total acceptable generation on feeders M1, M3, M5, M7 = 54 MW
Total acceptable generation on feeders M2, M4, M6, M8 = 54 MW
Cumulative Generation on station cannot exceed 63 MW
Currently there is no Application received on this Station

Bronte TS DESN2
Total acceptable generation on feeders M23,M24,M25,M26,M27,M28 = 53 MW
Currently there is no Application received on this Station

Brown Hill TS					
Total acceptable generation on M1, M2, M3, M4, M11, M12 = 84 MW					
Station Queue Position	M12	M1 - (%)	M11	M2 - (%)	M3
1	969 (10 MW)				
2	970 (10 MW)				
3	1825 (10 MW)				
4			1826 (10 MW)		
5			1827 (10 MW)		
6					1828 (10 MW)
7					1829 (10 MW)
8		1932 (10 MW)			
CIA Ineligible		1933 (10 MW)			
CIA Ineligible		1934 (10 MW)			
CIA Ineligible				1935 (10 MW)	
CIA Ineligible				1936 (10 MW)	
CIA Ineligible				1937 (10 MW)	

Buchanan TS		
Total acceptable generation on feeders M21,M23,M25,M27,M29,M37= 20MW		
Total acceptable generation on feeders M22,M24,M26,M28,M30,M38 = 20MW		
Cumulative generation on station cannot exceed 42 MW		
	B	Y
Station Queue Position	M21 - (A)	M22
1	1017 (10 MW)	
2	1018 (10 MW)	
CIA Ineligible	1280 (10 MW)	
CIA Ineligible	1281 (10 MW)	
3		1994 (2.85 MW)
4		2125 (10 MW)
5		2126 (7 MW)

Bunting TS
Total acceptable generation on feeders M55, M56, M57, M61, M62, M63 = 21.5 MW
Total acceptable generation on feeders M75, M76, M77, M81, M82 = 29.9 MW
Cumulative Generation on station cannot exceed 51.4 MW
For any information or inquiries please contact Horizon Utilities Corporation

Burleigh HVDS
Total acceptable generation on feeders F1, F2 = 2 MW
Currently there is no Application received on this Station

Burlington TS
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6 = 22 MW
Total acceptable generation on feeders M31,M32,M33,M34,M35,M36 = 23 MW
Cumulative Generation on staion cannot exceed 48 MW
Currently there is no Application received on this Station

Butternut DS	
Acceptable Generation = 11.4 MW	
Station Queue Position	F2
1	10040 (2036 - 5 MW)

Project 10040 has applied to connect to Frontenac TS

Buttonville TS
Total acceptable generation on feeders M1,M3,M5,M7,M9,M11 = 22 MW
Total acceptable generation on feeders M2,M4,M6,M8,M10,M12 = 17 MW
Cumulative Generation on station cannot exceed 45 MW
Currently there is no Application received on this Station

Caledonia TS			
Total acceptable generation on feeders M3, M4, M5, M6 = 55 MW			
Station Queue Position	M4 - (SC)	M5 - (SC)	M3 - (SC)
1	10650 (992 - 10 MW)		
2	10720 (1518 - 10 MW)		
3		10660 (1943 - 10 MW)	
CIA pending		10670 (1944 - 10 MW)	
CIA Ineligible			10770 (1945 - 10 MW)

Calstock HVDS
Total acceptable generation on feeders F1,F2 = 4 MW
Currently there is no Application received on this Station

Campbell TS DESN1 (T1&T2)
Total acceptable generation on feeders M11,M12,M13,M14,M21,M22,M23,M24 = 14 MW
Total acceptable generation on feeders M31,M32,M33,M34,M41,M42,M43,M44 = 16 MW
Cumulative Generation on station cannot exceed 30 MW
Currently there is no Application received on this Station

Campbell TS DESN2 (T3&T4)
Total acceptable generation on feeders M51,M52,M53,M54,M61,M62,M63,M64 = 13 MW
Currently there is no Application received on this Station

Carlaw TS
Total acceptable generation on transformer winding A1/A2 ("A1/A2") = 14 MW
Total acceptable generation on transformer winding A6/A7 ("A6/A7") = 6 MW
Cumulative Generation on station cannot exceed 21 MW
For any information or inquiries please contact Toronto Hydro

Carling TS
Total acceptable generation on transformer winding K/Y ("K/Y") = 16 MW
Total acceptable generation on transformer winding Q/Z ("Q/Z") = 14 MW
Cumulative Generation on station cannot exceed 31 MW
For any information or inquiries please contact Hydro Ottawa

Carlton TS DESN1 (T1&T4)
Total acceptable generation on feeders M13,M14, M15,M16 = 18 MW
Currently there is no Application received on this Station

Carlton TS DESN2 (T2&T3)		
Total acceptable generation on feeders A1,A2,A3,A4,A6,M7,M17,M18 = 13 MW		
Total acceptable generation on feeders M10, M11,M12,M20,M21,M25 = 3 MW		
Cumulative Generation on station cannot exceed 16 MW		
	H/K	B/Y
Station Queue Position	M17	
CIA pending	10710 (3.58 MW)	

Cecil TS DESN1
Total acceptable generation on transformer winding A1/A2 ("A1/A2") = 5 MW
Total acceptable generation on transformer winding A3/A4 ("A3/A4") = 14 MW
Cumulative Generation on A1/A2 & A3/A4 cannot exceed 19 MW
Currently there is no Application received on this Station

Cecil TS DESN2
Total acceptable generation on transformer winding A5/A6 ("A5/A6") = 17 MW
Total acceptable generation on transformer winding A7/A8 ("A7/A8") = 24 MW
Cumulative Generation on B & Y cannot exceed 42 MW
Currently there is no Application received on this Station

Cedar TS DESN1 (T1&T2)
Total acceptable generation on feeders M11,M12,M13,M14, M21,M22,M23,M24 = 17 MW
Total acceptable generation on feeders M61, M62, M63, M64 = 6 MW
Cumulative Generation on station cannot exceed 23 MW
For any information or inquiries please contact Guelph Hydro

Cedar TS DESN2 (T7&T8)
Total acceptable generation on feeders M71, M72, M73, M74, M81, M82, M83, M84 = 35 MW
For any information or inquiries please contact Guelph Hydro

Cedar Mills DS	
Acceptable Generation = 4 MW	
Station Queue Position	F1
Queue Exempt	10990 (0.276 MW)

Project 10990 has applied to connect to Kleinburg TS

Centralia TS			
Total acceptable generation on feeders M1, M2, M3, M4 = 29 MW			
Station Queue Position	M3 - (%)	M4 - (%)	M1
Queue Exempt			10410 (0.25 MW)
1	96 (10 MW)		
2		972 (10 MW)	
3		973 (8 MW)	
CIA Ineligible		1045 (9 MW)	
CIA Ineligible		1046 (9 MW)	
CIA Ineligible		895 (8 MW)	
CIA Ineligible		896 (10 MW)	
CIA Ineligible	1890 (9 MW)		

Project 10410 has applied to connect to Kirkton DS

Charles TS DESN1
Acceptable generation on transformer winding A5/A6 ("A5/A6") = 17 MW
Acceptable generation on transformer winding A7/A8 ("A7/A8") = 12 MW
Cumulative Generation on A5/A6 & A7/A8 cannot exceed 29 MW
Currently there is no Application received on this Station

Charles TS DESN2
Acceptable generation on transformer winding A1/A2 ("A1/A2") = 13 MW
Acceptable generation on transformer winding A3/A4 ("A3/A4") = 14 MW
Cumulative Generation on A1/A2 & A3/A4 cannot exceed 27 MW
Currently there is no Application received on this Station

Cherrywood TS
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 82 MW
Currently there is no Application received on this Station

Chesterville TS		
Total acceptable generation on feeders M2, M4 = 33 MW		
Station Queue Position	M2 - (%)	M4 - (%)
1	1191 (10 MW)	
2		1192 (10 MW)
3	1193 (10 MW)	
CIA Ineligible	1194 (10 MW)	
CIA Ineligible		1195 (10 MW)
CIA Ineligible	1817 (10 MW)	
CIA Ineligible		1818 (10 MW)
CIA Ineligible		1877 (9 MW)
CIA Ineligible	1878 (9 MW)	

Clarabelle TS				
Total acceptable generation on feeders M4, M5, M6, M7, M8 = 78 MW				
Station Queue Position	M5	M6 - (%)	M7 - (%)	M8 - (%)
Queue Exempt				2171 (0.190 MW)
1			1599 (9 MW)	
2			1600 (9 MW)	
3			1601 (9 MW)	
4	1613 (9 MW)			
5	1614 (9 MW)			
6	1615 (9 MW)			
7		1616 (9 MW)		
8		1617 (9 MW)		
CIA Ineligible		1618 (9 MW)		
CIA Ineligible				1619 (9 MW)
CIA Ineligible				1620 (9 MW)
CIA Ineligible				1621 (9 MW)
CIA Ineligible			1824 (10 MW)	

Project 2171 has applied to connect to Azilda DS

Clarence HVDS
Total acceptable generation on feeders F1, F2 = 2 MW
Currently there is no Application received on this Station

Clarke TS	
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6,M7,M8 = 73 MW	
Station Queue Position	M2 - (A)
1	363 (0.3 MW)
2	885 (10 MW)
3	1338 (10 MW)
CIA Ineligible	1339 (10 MW)

Project 363 has applied to connect to Birr DS

Clarksburg DS	
Acceptable Generation = 5 MW	
Station Queue Position	F2
CIA Ineligible	682 (0.3 MW)

Project 682 has applied to connect to Meaford TS

Clearwater Bay HVDS
Total acceptable generation on feeders F1, F2 = 4 MW
Currently there is no Application received on this Station

Cobden HVDS
Total acceptable generation on feeders F2, F3, F4 = 7 MW
Currently there is no Application received on this Station

Cobden TS		
Acceptable generation on feeder M6 = 12 MW		
Acceptable generation on feeder M2 = 13 MW		
Cumulative generation on station cannot exceed 13.8 MW		
	T1	T2
Station Queue Position	M6	M2
Queue Exempt		1257 (0.1 MW)
1	601 (9 MW)	
2		645 (1.25 MW)
3		819 (0.50 MW)
4		1237 (2.95 MW)

Project 645 has applied to connect to Northcote DS

Project 1257 has applied to connect to Beachburg DS

Project 819 has applied to connect to Beachburg DS

Cochrane West HVDS	
Total acceptable generation on feeders F1, F2 = 3 MW	
Station Queue Position	F1
CIA pending	10210 (2331 - 0.979 MW)

Coboconk DS	
Acceptable Generation = 6 MW	
Station Queue Position	F2
1	1372 (0.5 MW)

Project 1372 has applied to connect to Lindsay TS

Constance HVDS			
Acceptable generation on feeder F1 = 13 MW			
Total acceptable generation on feeder F2, F4 = 16 MW			
Cumulative generation on station cannot exceed 17 MW			
	T1	T2	
Station Queue Position	F1 - (%)	F2 - (%)	F4 - (%)
Queue Exempt			275 (0.065 MW)
1		146 (10 MW)	
2		134 (0.8 MW)	
CIA Ineligible		415 (9.9 MW)	
CIA Ineligible	416 (9.9 MW)		
CIA Ineligible		418 (9.9 MW)	
CIA Ineligible	420 (9.9 MW)		
CIA Ineligible			1892 (9 MW)

Cooksville TS DESN2
Total acceptable generation on feeders M17,M19,M21,M18,M20,M22 = 59 MW
Currently there is no Application received on this Station

Craig HVDS
Total acceptable generation on feeders F1, F2, F3 = 10 MW
Currently there is no Application received on this Station

*Crilly HVDS	
Acceptable Generation = 0.3 MW	
Station Queue	F1 - (%)
CIA Ineligible	368 (4.8 MW)
CIA Ineligible	369 (4.8 MW)

*Equipment beyond the Hydro One supply station is owned by third parties hence there can be no reverse flow through the station. This limits the amount of generation that can connect to this station.

Crosby TS - 44 kV		
Total acceptable generation on feeders M1,M2 = 47 MW		
Station Queue Position	M1	M2
1	1731 (8.5 MW)	
2	1732 (8.5 MW)	
3	1914 (9.99 MW)	
4		10170 (1149 - 10 MW)
5		10290 (10 MW)

Crosby TS - 27.6 kV		
Total acceptable generation on feeders M3, M5 = 21 MW		
Acceptable generation on feeder M6 = 21 MW		
Cumulative Generation on station cannot exceed 23 MW		
	T1	T2
Station Queue Position		M6
1		1909 (9.99 MW)
2		1996 (10 MW)

Crow River HVDS
Acceptable generation on feeder F1 = 3 MW
Acceptable generation on feeder F2 = 5 MW
Cumulative Generation on station cannot exceed 5 MW
Currently there is no Application received on this Station

Crowland TS			
Total acceptable generation on feeders M13,M14,M15,M16,M17,M18,M19,M20,M21,M22 = 61 MW			
Station Queue Position	M13 - (A)	M19 - (A)	M18
1	539 (10 MW)		
CIA Ineligible	540 (10 MW)		
2		1346 (9.5 MW)	
3		1347 (9.5 MW)	
CIA Ineligible	1287 (10 MW)		
CIA Ineligible	1288 (10 MW)		
CIA Ineligible	1289 (10 MW)		
CIA Ineligible	1290 (10 MW)		
CIA Ineligible	1291 (10 MW)		
CIA Ineligible		1349 (10 MW)	
CIA Ineligible	1352 (8.5 MW)		
4			1388 (10 MW)
5			1389 (10 MW)

Crysler DS	
Acceptable Generation = 3.5 MW	
Station Queue Position	F2
CIA Ineligible	1461 (0.4999 MW)
CIA Ineligible	10520 (1369 - 0.065 MW)
CIA Ineligible	10550 (0.1 MW)
CIA Ineligible	10760 (0.250 MW)

Project 1461 has applied to connect to St. Isidore TS

Project 10520 has applied to connect to St. Isidore TS

Project 10550 has applied to connect to St. Isidore TS

Project 10760 has applied to connect to St. Isidore TS

Crystal Falls TS		
Total acceptable generation on feeders M1, M2 = 21.7 MW		
Station Queue Position	M2	M1 - (%)
1	10 (8.5 MW)	
2		1122 (10 MW)
3		1430 (8.4 MW)
CIA Ineligible		1823 (10 MW)
CIA Ineligible		1879 (9 MW)

Cumberland HVDS
Total acceptable generation on feeder F2, F4 = 4 MW
Total acceptable generation on feeder F1, F3 = 3 MW
Cumulative Generation on station cannot exceed 5 MW
Currently there is no Application received on this Station

Cumberland TS
Total acceptable generation on feeders M22,M24,M26,M28,M30 = 17 MW
Total acceptable generation on feeders M21,M23,M25,M27,M29 = 20 MW
Cumulative Generation on station cannot exceed 46 MW
Currently there is no Application received on this Station

Dack DS	
Acceptable Generation = 1.5 MW	
Station Queue Position	F1
CIA pending	10180 (2241 - 0.8 MW)

Project 10180 has applied to connect to Kirkland Lake TS

Deep River HVDS
Acceptable generation on feeders F1 = 5 MW
Total acceptable generation on feeders F2, F3 = 6 MW
Acceptable generation on feeders F5 = 6 MW
Cumulative Generation on station cannot exceed 12 MW
Currently there is no Application received on this Station

Detweiler TS		
Total acceptable generation on feeders M11, M12, M13 = 22 MW		
Station Queue Position	M12	M13
1	1571 (7.825 MW)	
2		1684 (10 MW)

Dobbin HVDS
Acceptable generation on feeder F1 = 13 MW
Acceptable generation on feeder F2 = 13 MW
Cumulative Generation on station cannot exceed 14 MW
Currently there is no Application received on this Station

Douglas Point TS				
Total acceptable generation on feeders M1, M2, M3, M4, M5, M8 = 51.5 MW				
Station Queue Position	M6 - (%)	M8 - (%)	M4 - (%)	M1 - (%)
Queue Exempt	10790 (0.250 MW)			
1	45a (4.4 MW)			
2	45b (10 MW)			
3			30 (8.5 MW)	
4		44a (10 MW)		
5		44b (10 MW)		
6		44c (4 MW)		
CIA Ineligible	40a (10 MW)			
CIA Ineligible	40b (8 MW)			
CIA Ineligible			121a (10 MW)	
CIA Ineligible			121b (10 MW)	
CIA Ineligible	139 (9 MW)			
CIA Ineligible			140 (9 MW)	
CIA Ineligible		394 (0.6 MW)		
CIA Ineligible			240 (10 MW)	
CIA Ineligible		602 (9.9 MW)		
CIA Ineligible		603 (9.9 MW)		
CIA Ineligible	808 (9.9 MW)			
CIA Ineligible	809 (9.9 MW)			
CIA Ineligible				395 (10 MW)

Project 10790 has applied to connect to Reid Corners DS

Dryden Rural DS	
Acceptable Generation = 4.7 MW	
Station Queue Position	F2
1	2041 (2.6 MW)

Project 2041 has applied to connect to Dryden TS

Dryden TS		
Total acceptable generation on feeders M1, M3 = 22.9 MW		
Station Queue Position	M1 - (%)	M3
1		1986 (10 MW)
2	2041 (2.6 MW)	
3		10080 (2136 - 10 MW)
CIA Ineligible	10090 (2137 - 10 MW)	

Project 2041 has applied to connect to Dryden Rural DS

Dufferin TS DESN1
Acceptable generation on transformer winding A1/A2 ("A1/A2") = 10 MW
Acceptable generation on transformer winding A3/A4 ("A3/A4") = 5 MW
Cumulative Generation on A1/A2 & A3/A4 cannot exceed 15 MW
Currently there is no Application received on this Station

Dufferin TS DESN2
Acceptable generation on transformer winding A5/A6 ("A5/A6") = 15 MW
Acceptable generation on transformer winding A7/A8 ("A8/A8") = 8 MW
Cumulative Generation on A5/A6 & A7/A8 cannot exceed 24 MW
Currently there is no Application received on this Station

Dundas TS
Total acceptable generation on M1, M2, M3, M4, M5, M6, M7, M8 = 71 MW
Currently there is no Application received on this Station

Dundas TS # 2
Total acceptable generation on M11, M12, M13, M14, M15, M16 = 52 MW
Currently there is no Application received on this Station

Dunnville TS	
Total acceptable generation on feeders M1, M2 = 22 MW	
Station Queue Position	M2 - (A)
1	126 (10 MW)
2	377 (9.9 MW)
CIA Ineligible	228 (2 MW)
CIA Ineligible	1316 (9.9 MW)

Duplex TS DESN1
Acceptable generation on transformer winding A1/A2 ("A1/A2") = 11 MW
Acceptable generation on transformer winding A3/A4 ("A3/A4") = 9 MW
Cumulative Generation on A1/A2 & A3/A4 cannot exceed 20 MW
Currently there is no Application received on this Station

Duplex TS DESN2
Acceptable Generation = 14 MW
Currently there is no Application received on this Station

Dymond TS		
Total acceptable generation on feeders M1, M2, M3 = 29.5 MW		
Station Queue Position	M3	M1- (%)
1	252 (9.5 MW)	
2		1119 (10 MW)
3		1326 (10 MW)

Ear Falls TS
Acceptable Generation on M1 = 10 MW
Currently there is no Application received on this Station

Elgin TS DESN1(T1&T2)
Total acceptable generation on feeders M22,M23,M24,M25,M26,M27,M28,M30,M31,M32,M33,M34 = 8 MW
Total acceptable generation on feeders M41,M42,M43,M44,M45,M46,M47,M48 = 7 MW
Cumulative Generation on station cannot exceed 15 MW
Currently there is no Application received on this Station

Elgin TS DESN2(T3&T4)
Total acceptable generation on feeders M51, M52, M53, M61, M62, M63= 25 MW
Currently there is no Application received on this Station

Ellesemere TS
Total acceptable generation on feeders M22,M24,M26,M28,M30,M32 = 18 MW
Total acceptable generation on feeders M21,M23,M25,M27,M29,M31 = 21 MW
Cumulative Generation on station cannot exceed 39 MW
Currently there is no Application received on this Station

Elliot Lake TS		
Total acceptable generation on feeders M1, M3 = 16 MW		
Station Queue Position	M3 - (%)	M1 - (%)
2	10830 (1574 - 5.5 MW)	
1		1672 (9 MW)
CIA Ineligible		1673 (9 MW)
CIA Ineligible		1711 (9 MW)
CIA Ineligible	2043 (3 MW)	

Elmira TS			
Total acceptable generation on feeders M1, M2, M3= 28 MW			
Station Queue Position	M2	M1	M3
1	41 (9 MW)		
2	43 (9 MW)		
3	558 (3 MW)		
4		1313 (2.85 MW)	
5			10200 (2.9 MW)

Erindale TS DESN1 (T1&T2)
Total acceptable generation on feeders M31,M33,M35,M37,M39,M41 = 21 MW
Total acceptable generation on feeders M32,M34,M36,M38,M40,M42 = 26 MW
Cumulative Generation on station cannot exceed 48 MW
Currently there is no Application received on this Station

Erindale TS DESN2 (T3&T4)
Total acceptable generation on feeders M23, M24, M25, M26, M27, M28, M29, M30= 94 MW
Currently there is no Application received on this Station

Erindale TS DESN3 (T5&T6)
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8= 104 MW
Currently there is no Application received on this Station

Espanola DS	
Acceptable Generation = 3.9 MW	
Station Queue Position	F1
1	2127 (1 MW)

Project 2127 has applied to connect to Espanola TS

Espanola TS		
Total acceptable generation on feeders M1, M2 = 18 MW		
Station Queue Position	M1	M2
1		2044 (3.1 MW)
2	2127 (1 MW)	
3		2289 (2.5 MW)

Project 2127 has applied to connect to Espanola DS

Essex TS
Total acceptable generation on feeders M5, M6, M7, M8, M10, M11 = 30 MW
For any information or inquiries please contact EnWin Utilities

Eton HVDS	
Total acceptable generation on feeders F1,F2,F3 = 8 MW	
Station Queue Position	F1 - (A)
CIA Ineligible	1554 (6 MW)

Everett TS				
Total acceptable generation on feeders M5, M6, M7, M8 = 70 MW				
Station Queue Position	M5 - (A)	M6	M7 - (%)	M8
1	550 (10 MW)			
2	1678 (10 MW)			
3	1782 (10 MW)			
CIA Ineligible	1783 (10 MW)			
4		2081 (10 MW)		
5				2086 (10 MW)
6			10280 (2087 - 10 MW)	
7				1832 (10 MW)
CIA Ineligible			2088 (10 MW)	

Fairbank TS DESN1 (T1&T3)
Total acceptable generation on feeders M3, M5, M7, M8, M11, M12 = 65 MW
Currently there is no Application received on this Station

Fairbank TS DESN2 (T2&T4)
Total acceptable generation on feeders M1, M2, M4, M6, M9, M10, M23, M24 = 58 MW
Currently there is no Application received on this Station

Fairchild TS DESN1 (T1&T2)
Total acceptable generation on feeders M1,M3,M5,M7,M9,M11 = 19 MW
Total acceptable generation on feeders M2,M4,M6,M8,M10,M12 = 20 MW
Cumulative Generation on station cannot exceed 39 MW
Currently there is no Application received on this Station

Fairchild TS DESN2 (T3&T4)
Total acceptable generation on feeders M21,M23,M25,M27,M29,M31 = 11 MW
Total acceptable generation on feeders M22,M24,M26,M28,M30,M32 = 22 MW
Cumulative Generation on stationi cannot exceed 35 MW
Currently there is no Application received on this Station

Fauquier HVDS
Total acceptable generation on feeders F1, F2 = 2 MW
Currently there is no Application received on this Station

Fergus TS				
Total acceptable generation on feeders M1, M2, M3, M4, M7, M8 = 98 MW				
Station Queue Position	M1 - (A)	M3 - (%)	M2	M8
1	25 (10 MW)			
2	462 (9 MW)			
3	463 (9 MW)			
4	464 (7.5 MW)			
CIA Ineligible	233 (9 MW)			
CIA Ineligible	643 (9 MW)			
CIA Ineligible	513 (10 MW)			
CIA Ineligible	867 (9 MW)			
CIA Ineligible	868 (9 MW)			
CIA Ineligible	560 (10 MW)			
CIA Ineligible	974 (6 MW)			
5		1127 (10 MW)		
6		1128 (10 MW)		
7		1129 (10 MW)		
8		1130 (2 MW)		
9			1580 (10 MW)	
10			1581 (10 MW)	
11			1655 (10 MW)	
CIA Ineligible		1822 (10 MW)		
CIA Ineligible				2230 (10 MW)

Finch TS DESN1 (T1&T2)
Total acceptable generation on feeders M1,M3,M5,M7,M9,M11 = 16 MW
Total acceptable generation on feeders M2,M4,M6,M8,M10,M12 = 22 MW
Cumulative Generation on station cannot exceed 41 MW
Currently there is no Application received on this Station

Finch TS DESN2 (T3&T4)
Total acceptable generation on feeders M21,M23,M25,M27,M29,M31 = 22 MW
Total acceptable generation on feeders M22,M24,M26,M28,M30,M32 = 20 MW
Cumulative Generation on station cannot exceed 43 MW
Currently there is no Application received on this Station

Forest Jura HVDS				
Total acceptable generation on feeders F1, F3 = 16.4 MW				
Total acceptable generation on feeders F2, F4 = 16.5 MW				
Cumulative generation on station cannot exceed 18.9 MW				
	T1		T2	
Station Queue Position	F1 - (%)	F3 - (%)	F2 - (A) and (%)	F4 - (%)
1			27 (9.9 MW)	
2			69 (6.6 MW)	
CIA Ineligible		219 (9.9 MW)		
CIA Ineligible				220 (9.9 MW)
CIA Ineligible		362 (10 MW)		
CIA Ineligible	397 (10 MW)			
CIA Ineligible		398 (10 MW)		
CIA Ineligible	505 (2 MW)			
CIA Ineligible		591 (10 MW)		
CIA Ineligible			592 (10 MW)	

Project 505 has applied to connect to Springvale DS

Forest Lea HVDS
Total acceptable generation on feeders F1, F2 = 6 MW
Total acceptable generation on feeders F3, F4 = 6 MW
Cumulative Generation on station cannot exceed 7 MW
Currently there is no Application received on this Station

Fort Frances TS	
Acceptable Generation on M1 = 14.3 MW	
Station Queue Position	M1 - (%)
1	1356 (10 MW)
CIA Ineligible	1353 (6 MW)
CIA Ineligible	1354 (8 MW)

Fort William TS
Total acceptable generation on M1,M2,M3,M4,M5,M6,M7,M8,M9,M10 = 67 MW
For any information or inquiries please contact Thunder Bay Hydro

Frontenac TS			
Total acceptable generation on feeders M1, M2, M3, M4, M5, M8 = 75 MW			
Station Queue Position	M8 - (A)	M1 - (A)	M3 - (%)
1	1196 (10 MW)		
2		1198 (10 MW)	
3	1526 (10 MW)		
4	1586 (10 MW)		
CIA Ineligible	1597 (8.5 MW)		
CIA Ineligible	1598 (8.5 MW)		
5		1733 (10 MW)	
6		1734 (10 MW)	
CIA Ineligible		1679 (10 MW)	
CIA Ineligible		1743 (10 MW)	
CIA Ineligible		1820 (10 MW)	
CIA Ineligible		1821 (10 MW)	
CIA Ineligible		1963 (10 MW)	
7			1964 (10 MW)
8			10040 (2036 - 5 MW)
CIA Ineligible			1987 (10 MW)
CIA Ineligible	2129 (9 MW)		

Project 10040 has applied to connect to Butternut DS

Galt TS
Total acceptable generation on feeders M11,M13,M15,M17,M19,M21 = 51.2 MW
Total acceptable generation on feeders M12,M14,M16,M18,M20,M22 = 50.9 MW
Cumulative Generation on station cannot exceed 102.1 MW
For any information or inquiries please contact Cambridge North Dumfries Hydro (CND)

Glendale TS DESN1(T1&T2)
Total acceptable generation on feeders M31,M32,M33,M34 = 4 MW
Total acceptable generation on feeders M5,M8,M23,M24 = 5 MW
Cumulative Generation on station cannot exceed 11 MW
Currently there is no Application received on this Station

Glengarry DS	
Acceptable Generation = 8.3 MW	
Station Queue Position	F1
1	1074 (7.5 MW)

Project 1074 has applied to connect to St. Isidore TS

Glengrove TS DESN1 (T1&T3)
Acceptable Generation = 25 MW
Currently there is no Application received on this Station

Glengrove TS DESN2 (T2&T4)
Acceptable Generation = 24 MW
Currently there is no Application received on this Station

Glen Sandfield DS	
Acceptable Generation = 3.7 MW	
Station Queue Position	F3
Queue Exempt	10530 (0.1 MW)

Project 10530 has applied to connect to Longueuil TS

Goderich TS		
Total acceptable generation on feeders M1, M2, M3, M4 = 0 MW		
Station Queue Position	M2 - (%)	M1 - (%)
N/A	147 (10 MW)	
N/A	488 (10 MW)	
N/A	419 (9.9 MW)	
N/A	424 (9.9 MW)	
N/A		427 (9.9 MW)
N/A		421 (9.9 MW)

Goreway TS
Total acceptable generation on feeders M41,M43,M45,M47,M49,M51 = 25 MW
Total acceptable generation on feeders M42,M44,M46,M48,M50,M52 = 26 MW
Cumulative Generation on station cannot exceed 57 MW
Currently there is no Application received on this Station

Grand Bend East HVDS		
Acceptable generation on feeder F1 = 15 MW		
Acceptable generation on feeders F2 = 15.9 MW		
Cumulative generation on station cannot exceed 17 MW		
	T1	T2
Station Queue Position	F1 - (%)	F2 - (%)
1	122 (9 MW)	
CIA Pending	10910 (132a -6 MW)	
CIA Ineligible	132b (2.25 MW)	
CIA Ineligible	152 (8.25 MW)	
CIA Ineligible	133 (0.80 MW)	
CIA Ineligible	148 (10 MW)	
CIA Ineligible	149 (10 MW)	
CIA Ineligible		83 (10 MW)

Greely HVDS		
Acceptable generation on feeder F3 = 18 MW		
Total acceptable generation on feeder F2, F4 = 18 MW		
Cumulative generation on station cannot exceed 21 MW		
	T1	T2
Station Queue Position	F3	F2
1	1748 (10 MW)	
2		1749 (10 MW)

Halton TS
Total acceptable generation on feeders M22,M24,M26,M28,M30,M32 = 21 MW
Total acceptable generation on feeders M21,M23,M25,M27,M29,M31 = 21 MW
Cumulative Generation on station cannot exceed 42 MW
Currently there is no Application received on this Station

Hamilton Gage TS
Acceptable Generation = 94.6 MW
For any information or inquires please Horizon Utilities

Hamilton Nebo TS DESN 1	
Total acceptable generation on feeders M3, M4, M5, M6, M7, M8 = 63 MW	
Station Queue Position	M5 - (A)
1	654 (3.2 MW)
2	1819 (10 MW)
CIA Ineligible	1895 (9 MW)
CIA Ineligible	1956 (10 MW)

Hanlon TS
Total acceptable generation on feeders M11, M12, M13, M21, M22, M23 = 29 MW
Currently there is no Application received on this Station

Hanover TS				
Total acceptable generation on M1, M2, M3, M4, M5, H1E = 74 MW				
Station Queue Position	M4 - (%)	M2	H1E	M5 - (%)
1	157 (9 MW)			
2		142 (9 MW)		
3	143 (9 MW)			
4			159 (9 MW)	
5			160 (9 MW)	
6				261 (9 MW)
7				262 (9 MW)
8			783 (10 MW)	
CIA Ineligible	570 (9.9 MW)			
CIA Ineligible				1886 (9 MW)

Harrowsmith HVDS
Total acceptable generation on feeders F2, F3 = 7 MW
Total acceptable generation on feeders F4, F5 = 8 MW
Cumulative Generation on station cannot exceed 10 MW
Currently there is no Application received on this Station

Havelock TS					
Total acceptable generation on feeders M1, M2, M3, M4, M6 = 50.9 MW					
Station Queue Position	**M4 - (A)**	**M3**	**M2**	**M6**	**M1**
1	835 (6.7 MW)				
2		1669 (9.8 MW)			
3			1681 (10 MW)		
CIA Ineligible	1814 (10 MW)				
CIA Ineligible	1815 (10 MW)				
4				1816 (10 MW)	
CIA Ineligible	2128 (9 MW)				
5					10150 (2207 - 5.4 MW)

Hearst TS
Total acceptable generation on feeders M1, M2, M3 = 25 MW
Currently there is no Application received on this Station

Herridge Lake HVDS
Total acceptable generation on feeders F1, F2 = 2 MW
Currently there is no Application received on this Station

Highbury TS	
Total acceptable generation on feeders M11, M12, M13, M14, M15, M16, M17, M18 = 74 MW	
Station Queue Position	**M11**
1	1705 (10 MW)
CIA Pending	10980 (2143 - 10 MW)

Hinchey TS
Acceptable Generation = 18 MW
Currently there is no Application received on this Station

Hinchinbrooke HVDS
Total acceptable generation on feeders F1, F2, F3= 4 MW
Currently there is no Application received on this Station

Horner TS
Total acceptable generation on feeders M1,M3,M5,M7,M9= 19 MW
Total acceptable generation on feeders M2,M4,M6,M8,M10 = 17 MW
Cumulative Generation on station cannot exceed 38 MW
Currently there is no Application received on this Station

Horning TS
Total acceptable generation on feeders M2,M3,M4,M5,M6,M7,M8,M9,M10,M11 = 11 MW
Total acceptable generation on feeders M45,M46,M47,M48,M49,M50 = 2 MW
Cumulative Generation on station cannot exceed 14 MW
Currently there is no Application received on this Station

Hoyle HVDS
Total acceptable generation on feeders F1, F2 = 13 MW
Currently there is no Application received on this Station

Ingersoll TS						
Total acceptable generation on feeders M43,M45,M49,M51 = 48.4 MW						
Total acceptable generation on feeders M44,M46,M50,M52 = 46.7 MW						
Cumulative generation on station cannot exceed 95.1 MW						
	E			Z		
Station Queue Position	**M45**	**M43**	**M49 - (%)**	**M46 - (A)**	**M44 - (A)**	**M50 - (%)**
Queue Exempt		1493 (0.19 MW)				
1	1285 (10 MW)					
2	1324 (10 MW)					
3				1515 (10 MW)		
4				1516 (10 MW)		
CIA Ineligible				1701 (10 MW)		
5					1744 (9 MW)	
6					1745 (9 MW)	
CIA Ineligible					1802 (10 MW)	
7		1735 (8.5 MW)				
8			1736 (8.5 MW)			
CIA Ineligible				1853 (10 MW)		
9		1947 (10 MW)				
10						10440 (2249-8.5 MW)
CIA Ineligible			2302 (10 MW)			
CIA Ineligible						2303 (6.5 MW)

Project 1493 has applied to connect to Kintore DS

Iroquois Falls HVDS
Total acceptable generation on feeders F1, F2, F3 = 5.8 MW
Currently there is no Application received on this Station

J.Clarke Keith TS			
Total acceptable generation on M1, M2, M3, M4, M5, M6= 58 MW			
Station Queue Position	M5	M3 - (A)	M4 - (A)
1		689 (10 MW)	
2			1053 (10 MW)
3		1136 (10 MW)	
4		1137 (5 MW)	
5			1172 (10 MW)
CIA Ineligible			1173 (10 MW)
CIA Ineligible		1187 (10 MW)	
CIA Ineligible		1247 (10 MW)	
CIA Ineligible			1248 (10 MW)
CIA Ineligible			1249 (10 MW)
6	1351 (1 MW)		

Jarvis TS						
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7= 0 MW						
Station Queue Position	M2 - (SC)	M3 - (SC)	M4 - (SC)	M1 - (SC)	M6 - (SC)	M5 - (SC)
CIA Withdrawn					378 (9.9 MW)	
CIA Withdrawn			840 (8 MW)			
CIA Ineligible			993 (10 MW)			
CIA Ineligible			991 (10 MW)			
CIA Ineligible		943 (10 MW)				
CIA Ineligible					1392 (3 MW)	
CIA Ineligible					1107 (10 MW)	
CIA Ineligible	979 (9.9 MW)					
CIA Ineligible	980 (9.9 MW)					
CIA Ineligible				981 (9.9 MW)		
CIA Ineligible				982 (9.9 MW)		
CIA Ineligible						1106 (10 MW)
CIA Ineligible			1585 (10 MW)			
CIA Ineligible					1584 (10 MW)	
CIA Ineligible			384 (9 MW)			

Jellicoe HVDS # 3
Acceptable Generation on F1 = 0.8 MW
Currently there is no Application received on this Station

Kapuskasing TS			
Total acceptable generation on M1, M2, M3, M4 = 46 MW			
Station Queue Position	M3	M1	M4
1	67 (10 MW)		
2		68 (10 MW)	
3	2116 (7.5 MW)		
4			2199 (10 MW)
5			2202 (6 MW)

Kenilworth DS	
Acceptable Generation = 2.4 MW	
Station Queue Position	F1
Queue Exempt	680 (0.02 MW)

Project 680 has applied to connect to Palmerston TS

Kent TS						
Total acceptable generation on feeders M1,M3,M5,M7,M15,M17 = 58.4 MW						
Total acceptable generation on feeders M2,M4,M6,M8,M16,M18 = 54.4 MW						
Cumulative Generation on station cannot exceed 112.7 MW						
	B			Y		
Station Queue Position	M1 - (A)	M15 - (A)	M17 - (%)	M2 - (A)	M16 - (A)	M18 - (%)
1	49 (10 MW)					
2					38 (10 MW)	
3						76 (10 MW)
4	163 (9.9 MW)					
5		182 (9.9 MW)				
6				273 (10 MW)		
7				274 (10 MW)		
8					184 (9.9 MW)	
CIA Ineligible	410 (9.9 MW)					
CIA Ineligible				435 (9 MW)		
CIA Ineligible				436 (9 MW)		
CIA Ineligible	439 (9 MW)					
CIA Ineligible	440 (9 MW)					
9						441 (4.5 MW)
CIA Ineligible						442 (9 MW)
CIA Ineligible					474 (9 MW)	
CIA Ineligible					475 (9 MW)	
10		487 (8.5 MW)				
11			537 (9.9 MW)			
CIA Ineligible						555 (9.9 MW)
CIA Ineligible						572 (9 MW)
CIA Ineligible	593 (10 MW)					
CIA Ineligible	594 (10 MW)					
CIA Ineligible	595 (10 MW)					
CIA Ineligible	596 (10 MW)					
CIA Ineligible		372 (9.9 MW)				
CIA Ineligible				255 (9.9 MW)		
CIA Ineligible					642 (9.9 MW)	
CIA Ineligible				343 (3 MW)		
CIA Ineligible				795 (9.9 MW)		
CIA Ineligible					276 (10 MW)	
CIA Ineligible	470 (9.2 MW)					
CIA Ineligible			1178 (9.9 MW)			
CIA Ineligible	657 (8.4 MW)					
CIA Ineligible						1293 (9.6 MW)
CIA Ineligible			1773 (6 MW)			

King Edward TS
Acceptable generation on transformer winding J/Y ("J/Y") = 14 MW
Acceptable generation on transformer winding Q/Z ("Q/Z") = 10 MW
Cumulative Generation on J/Y & Q/Z cannot exceed 31 MW
Currently there is no Application received on this Station

Kingston Gardiner TS				
Total acceptable generation on feeders M3, M7, M8, M9, M10, M11, M12, M13, M14, M15 = 126 MW				
Station Queue Position	M14 - (A)	M11	M3 - (A)	M15
1	1588 (8.5 MW)			
2	1589 (8.5 MW)			
3	1590 (8.5 MW)			
4		1635 (0.4999 MW)		
CIA Pending	10800 (1670 - 7.5 MW)			
5			1720 (10 MW)	
6			1721 (10 MW)	
7			1722 (10 MW)	
CIA Ineligible	1664 (10 MW)			
CIA Ineligible			1750 (10 MW)	
CIA Ineligible			1751 (10 MW)	
8		1706 (10 WM)		
9		1707 (10 MW)		
CIA Ineligible	1708 (10 MW)			
CIA Ineligible			1728 (10 MW)	
CIA Ineligible			1729 (10 MW)	
CIA Ineligible			1730 (10 MW)	
10				2060 (9 MW)

Project 1635 has applied to connect to Reddendale DS

Kingsville TS									
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8, M9, M10= 35.5 MW									
Station Queue Position	M1	M2	M3	M4	M5	M7 - (SC)	M8	M9	M10
1				127 (9 MW)					
2					128 (9 MW)				
3							129 (9 MW)		
4							194 (8.49 MW)		
CIA sent			269 (12 MW)						
CIA sent						52 (9.9 MW)			
CIA sent	53 (9.9 MW)								
CIA Ineligible					346 (1 MW)				
CIA Ineligible				347 (1 MW)					
CIA Ineligible							348 (1 MW)		
CIA Ineligible	95 (6 MW)								
CIA Ineligible			361 (9.9 MW)						
CIA Ineligible			136 (7.96 MW)						
CIA Ineligible									471 (10 MW)
CIA Ineligible									496 (9.9 MW)
CIA Ineligible									497 (9.9 MW)
CIA Ineligible		498 (9.9 MW)							
CIA Ineligible		499 (9.9 MW)							
CIA Ineligible			500 (9.9 MW)						
CIA Ineligible			501 (9.9 MW)						
CIA Ineligible									538 (9.9 MW)
CIA Ineligible		285 (10 MW)							
CIA Ineligible						700 (4.24 MW)			
CIA Ineligible								493 (1.54 MW)	
CIA Ineligible			949 (7.5 MW)						
CIA Ineligible			950 (6 MW)						
CIA Ineligible			699 (6 MW)						
CIA Ineligible	2047 (0.8 MW)								

Kinmount DS	
Acceptable Generation = 4.3 MW	
Station Queue Position	F2
1	1462 (0.32 MW)

Project 1462 has applied to connect to Minden TS

Kintore DS	
Acceptable Generation = 3.9 MW	
Station Queue Position	F1
Queue Exempt	1493 (0.19 MW)

Project 1493 has applied to connect to Ingersoll TS

Kirkland Lake TS		
Total acceptable generation on M61, M62, G3K = 25.7 MW		
Station Queue Position	M62 - (%)	G3K - (%)
1	1420 (7.5 MW)	
2	1421 (7.5 MW)	
3	1414 (3 MW)	
4	1710 (7.5 MW)	
CIA Ineligible		1742 (10 MW)
CIA Ineligible	2288 (2 MW)	
CIA Ineligible	10180 (2241 - 0.8 MW)	

Project 10180 has applied to connect to Dack DS

Kirkton DS	
Acceptable Generation = 4.3 MW	
Station Queue Position	F1
Queue Exempt	10410 (0.25 MW)

Project 10410 has applied to connect to Centralia TS

Kleinburg TS			
Total acceptable generation on feeders M23,M24,M25,M26,M27,M28=20 MW			
Total acceptable generation on feeders M3,M4,M5,M6 M7,M8=11MW			
Cumulative generation on station cannot exceed 33 MW			
Station Queue Position	M24	M26	M8
Queue Exempt			10160 (0.030 MW)
Queue Exempt	10190 (2259 - 0.021 MW)		
Queue Exempt	1222 (0.125 MW)		
Queue Exempt		10990 (0.276 MW)	
1	1847 (10 MW)		

Project 1222 has applied to connect to Schomberg DS

Project 10190 has applied to connect to Schomberg DS

Project 10990 has applied to connect to Cedar Mills DS

Project 1847 has applied to connect to Schomberg DS

LaForest Road HVDS	
Total acceptable generation on feeders F1, F2 = 19 MW	
Station Queue Position	F1 - (%)
1	253 (14 MW)
CIA Ineligible	10260 (1650 - 6 MW)

Lambton TS				
Total acceptable generation on feeders M1,M3,M5 = 60 MW				
Total acceptable generation on feeders M2,M4 = 20 MW				
Cumulative generation on station cannot exceed 80 MW				
	T5			T6
Station Queue Position	M5 - (A)	M1 - (A)	M3 - (A)	M2 - (%)
1	1007 (10 MW)			
2	1008 (10 MW)			
3		856 (10 MW)		
4			1100 (10 MW)	
5			1101 (10 MW)	
CIA Ineligible			1102 (10 MW)	
6		807 (10 MW)		
CIA Ineligible		1139 (10 MW)		
CIA Ineligible		1140 (10 MW)		
7				1141 (10 MW)
8				1142 (10 MW)
CIA Ineligible				1143 (10 MW)
CIA Ineligible				1144 (10 MW)
CIA Ineligible				1145 (10 MW)
CIA Ineligible				1146 (10 MW)
CIA Ineligible		1284 (10 MW)		
CIA Ineligible			956 (9.9 MW)	
CIA Ineligible				1942 (9 MW)

Larchwood TS
Total acceptable generation feeders M3, M4 = 13 MW
Currently there is no Application received on this Station

Leaside TS DESN 1 - 13.8 kV
Total acceptable generation on feeders A1,A2,A3,A4,A5,A10,A11, A12,A13,A14,A16,A21,A22,A26,A27,A28 = 17 MW
Currently there is no Application received on this Station

Leaside TS DESN 2 - 27.6 kV
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6,M7,M8 = 19.8 MW
Currently there is no Application received on this Station

Leslie TS - DESN2
Total acceptable generation on feeders M21, M23, M25, M27, M29, M31 = 18 MW
Total acceptable generation on feeders M22, M24, M26, M28, M30, M32 = 22 MW
Cumulative Generation on station cannot exceed 41 MW
Currently there is no Application received on this Station

Lincoln Heights TS
Acceptable generation on transformer winding B ("B") = 2 MW
Acceptable generation on transformer winding Y("Y") = 5 MW
Cumulative Generation on station cannot exceed 11 MW
Currently there is no Application received on this Station

Lindsay TS				
Total acceptable generation on feeders M3,M5,M7 = 79 MW				
Total acceptable generation on feeders M4,M6,M8 = 82 MW				
Cumulative generation on station cannot exceed 92 MW				
	T1	T2		
Station Queue Position	M7 - (A)	M6 - (A)	M4	M8 - (A)
Queue Exempt		1623 (0.499 MW)		
1		1435 (10 MW)		
2			1436 (10 MW)	
3				1562 (8.5 MW)
4				1563 (8.5 MW)
5	1578 (8.5 MW)			
6				1674 (8.5 MW)
7	1372 (0.5 MW)			
8		1762 (9 MW)		
9		1763 (9 MW)		
CIA Ineligible		1764 (9 MW)		
CIA Ineligible		1812 (10 MW)		
CIA Pending	10930 (1887 - 9 MW)			
CIA Ineligible	1929 (10 MW)			
CIA Ineligible				1930 (10 MW)
CIA Ineligible		1931 (10 MW)		
CIA Ineligible		1940 (10 MW)		
CIA Pending			10390 (10 MW)	
CIA Ineligible	10810 (10 MW)			

Project 1372 has applied to connect to Coboconk DS

Lisgar TS
Acceptable generation on transformer winding J/Y ("J/Y") = 0 MW
Acceptable generation on transformer winding Q/Z ("Q/Z") = 12.5 MW
Cumulative Generation on J/Y & Q/Z cannot exceed 4 MW
Currently there is no Application received on this Station

Lodgeroom DS
Total acceptable generation on feeders F3,F4 = 8
Total acceptable generation on feeders F1,F2 = 6
Cumulative Generation on station cannot exceed 8
Currently there is no Application received on this Station

Longlac TS	
Total acceptable generation on feeders M1, M2 = 18.7 MW	
Station Queue Position	M1- (%)
1	1484 (10 MW)
2	10360 (2175 - 9.8 MW)

Longwood TS			
Total acceptable generation on feeders M23, M24, M25, M26 = 49 MW			
Station Queue Position	M23	M25	M24
1	1405 (10 MW)		
2			1226 (10 MW)
3			1231 (10 MW)
4		1811 (10 MW)	
5	1894 (9 MW)		

Longueuil DS	
Acceptable Generation = 8.3 MW	
Station Queue Position	F3
1	1746 (5 MW)

Project 1746 has applied to connect to Longueuil TS

Longueuil TS			
Total acceptable generation on feeders M23, M24, M25, M26 = 57 MW			
Station Queue Position	M23 - (A)	M25	M26
Queue Exempt	390 (0.18 MW)		
Queue Exempt	391 (0.1 MW)		
Queue Exempt	1573 (0.18 MW)		
Queue Exempt			10600 (1972 - 0.18 MW)
Queue Exempt	10530 (1370 - 0.1 MW)		
Queue Exempt	10510 (1997 - 0.250 MW)		
1	927 (10 MW)		
2	964 (10 MW)		
3	965 (10 MW)		
4		1746 (5 MW)	
5			1747 (10 MW)
6			10590 (1752 - 10 MW)

Project 390 has applied to connect to Stardale DS

Project 1573 has applied to connect to Stardale DS

Project 391 has applied to connect to Stardale DS

Project 1746 has applied to connect to Longueuil DS

Project 10600 has applied to connect to Plantagenet DS

Project 10530 has applied to connect to Glen Sandfield DS

Project 10510 has applied to connect to Stardale DS

Lorne Park TS
Total acceptable generation on feeders M2,M4,M6,M8,M10 = 17 MW
Total acceptable generation on feeders M1,M3,M5,M7,M9 = 24 MW
Cumulative Generation on station cannot exceed 41 MW
Currently there is no Application received on this Station

Lyn DS	
Acceptable Generation = 2.6 MW	
Station Queue Position	F1
CIA Ineligible	1457 (0.499 MW)

Project 1457 has applied to connect to Brockville TS

Malvern TS
Total acceptable generation on feeders M21,M31,M33,M35 = 20 MW
Total acceptable generation on feeders M22,M32,M34,M36 = 15 MW
Cumulative Generation on station cannot exceed 43 MW
Currently there is no Application received on this Station

Manby TS DESN1 (T3&T4)
Total acceptable generation on feeders M1M3,M5,M7,M9,M12 = 35 MW
Currently there is no Application received on this Station

Manby TS DESN2 (T5&T6)
Total acceptable generation on feeders M13,M16,M17,M20,M21,M24 = 42 MW
Currently there is no Application received on this Station

Manby TS DESN3 (T13&T14)
Total acceptable generation on feeders M4,M6,M8,M10,M23,M25,M27,M29 = 78 MW
Currently there is no Application received on this Station

Manitoulin TS		
Acceptable generation on feeder M25 = 26.1 MW		
Acceptable generation on feeder M26 = 26.3 MW		
	T3	T4
Station Queue Position	M25 - (%)	M26 - (%)
1	11a (1.6 MW)	
2	11b i (6.5 MW)	
4	10870 (11bii - 3.5 MW)	
5	10860 (34 - 9 MW)	
3		177a (8 MW)
6		10880 (177b - 2 MW)
7		10890 (138 - 6 MW)
CIA Ineligible	617 (9.6 MW)	
CIA Pending		10920 (1010 - 10 MW)
CIA Ineligible		1011 (10 MW)
CIA Ineligible		406 (10 MW)
CIA Ineligible		407 (10 MW)
CIA Ineligible	408 (10 MW)	
CIA Ineligible	409 (10 MW)	
CIA Ineligible	1376 (10 MW)	

Manitouwadge DS # 1
Acceptable Generation on F3 = 3 MW
Currently there is no Application received on this Station

Manitouwadge TS	
Total acceptable generation on feeders M1, M2, M3 = 10 MW	
Station Queue Position	M2
1	931 (9.8 MW)

Manotick HVDS	
Total acceptable generation on feeders F1, F2 = 7 MW	
Total acceptable generation on feeders F4, F5 = 4 MW	
Cumulative Generation on station can not exceed 7 MW	
Station Queue Position	F5
1	1520 (0.498 MW)
2	10350 (0.498 MW)

Marathon HVDS
Total acceptable generation on feeders F2, F3 = 4 MW
Currently there is no Application received on this Station

Margach HVDS	
Total acceptable generation on feeders F1, F2, F3 = 8.3 MW	
Station Queue Position	F2
1	2286 (3 MW)
2	10480 (2305 - 2.64 MW)

Marionville HVDS		
Total acceptable generation on feeders F1, F2 = 16 MW		
Station Queue Position	F1 - (%)	F2
1	1755 (10 MW)	
2		10900 (1756 - 6 MW)
CIA Ineligible	10400 (10 MW)	

Massey HVDS
Total acceptable generation on feeders F1, F3 = 4 MW
Currently there is no Application received on this Station

Mazinaw HVDS
Total acceptable generation on feeders F1, F2 = 3 MW
Currently there is no Application received on this Station

McCrimmon DS	
Acceptable Generation = 3.8 MW	
Station Queue Position	F3
CIA Ineligible	10540 (0.18 MW)

Project 10540 has applied to connect to St. Isidore TS

Meadowvale TS
Total acceptable generation on feeders M3, M4, M5, M6, M7, M8 = 131 MW
Currently there is no Application received on this Station

Meaford TS		
Total acceptable generation on feeders M1, M2 = 32 MW		
Station Queue Position	M1 - (%) and (A)	M2 - (%)
1		135 (1.65 MW)
2	4 (9 MW)	
3	5 (9 MW)	
4	109 (10 MW)	
CIA Ineligible	1131 (10 MW)	
CIA Ineligible		720 (10 MW)
CIA Ineligible		721 (10 MW)
CIA Ineligible	682 (0.3 MW)	
CIA Ineligible	1361 (10 MW)	

Project 682 has applied to connect to Clarksburg DS

Midhurst TS					
Total acceptable generation on feeders M3, M4, M5, M6, M7, M8, M9, M10 = 109.8 MW					
Station Queue Position	M10 - (A)	M3	M9	M4	M5 - (%)
1	1337 (10 MW)				
2	1437 (10 MW)				
3	1810 (10 MW)				
CIA Ineligible	1917 (9 MW)				
4		2027 (10 MW)			
5			2033 (10 MW)		
6				2117 (10 MW)	
7				2192 (10 MW)	
8		2231 (10 MW)			
9		2232 (10 MW)			
10					2243 (10 MW)
11			10340 (2244 - 9.5 MW)		
CIA Ineligible					2245 (10 MW)

Milford DS	
Acceptable Generation = 1.6 MW	
Station Queue Position	F2 - (%)
Queue Exempt	1148 (0.08 MW)
CIA Ineligible	2049 (9 MW)

Project 2049 has applied to connect to Picton TS

Project 1148 has applied to connect to Picton TS

Minaki HVDS
Total acceptable generation on feeders F1, F2 = 6 MW
Currently there is no Application received on this Station

Minden TS			
Total acceptable generation on feeders M1,M3 = 26 MW			
Total acceptable generation on feeders M2,M4 = 28 MW			
Cumulative Generation on station cannot exceed 31 MW			
	T1		T2
Station Queue Position	M3 - (%)	M1 - (%)	M4
1			707 (10 MW)
2	1809 (10 MW)		
3	1462 (0.32 MW)		
4	2065 (10 MW)		
CIA Ineligible		1512 (10 MW)	
CIA Ineligible		1513 (10 MW)	
CIA Ineligible		1514 (10 MW)	

Project 1462 has applied to connect to Kinmount DS

Modeland TS
Total acceptable generation on feeders M23,M25,M27,M29,M31 = 52.6 MW
Total acceptable generation on feeders M24,M26,M28,M30 = 50.8 MW
Cumulative Generation on station cannot exceed 103.4 MW
For any information or inquiries please contact Blue Water Power Distribution Corporation

Mohawk TS
Total acceptable generation on feeders M52,M53,M62,M63,M64 = 11 MW
Total acceptable generation on feeders M71,M72,M73,M81,M82,M83 = 9 MW
Cumulative Generation on station cannot exceed 21 MW
Currently there is no Application received on this Station

Monteith HVDS
Total acceptable generation on feeders F1, F2 = 6 MW
Currently there is no Application received on this Station

Mooselake TS
Total acceptable generation on feeders M2,M5 = 2 MW
Total acceptable generation on feeders M3,M6 = 4 MW
Cumulative generation on station cannot exceed 5 MW
For any information or inquiries please contact Atikokan Hydro Inc.

Moosonee HVDS
Total acceptable generation on feeders F1, F2, F3 = 10 MW
Currently there is no Application received on this Station

Morrisburg TS			
Total acceptable generation no feeders M23, M25, M26 = 65.4 MW			
Station Queue Position	M25 - (%)	M26 - (%)	M23 - (%)
1	1335 (10 MW)		
2	1336 (10 MW)		
3	952 (0.76 MW)		
4	1384 (10 MW)		
5		1489 (10 MW)	
6		1490 (10 MW)	
7			1503 (9.99 MW)
8			10470 (1504 - 4.62 MW)
CIA Ineligible		1645 (10 MW)	
CIA Ineligible		1808 (10 MW)	
CIA Ineligible			1907 (9.99 MW)
CIA Ineligible	1957 (9 MW)		

Mountain Chute HVDS
Total acceptable generation on feeders F1, F2 = 1 MW
Currently there is no Application received on this Station

Murillo HVDS	
Acceptable Generation = 0 MW	
Station Queue Position	F6 - (%)
CIA Ineligible	954 (10 MW)
CIA Ineligible	1121 (10 MW)

Murray TS DESN1 (T11&T12)
Total acceptable generation on feeders M51,M52,M53,M54,M55,M56 = 12 MW
Total acceptable generation on feeders M25,M26,M27,M28,M29,M30 = 13 MW
Cumulative Generation on station cannot exceed 25 MW
Currently there is no Application received on this Station

Murray TS DESN2 (T13&T14)
Total acceptable generation on feeders M10,M11,M13 = 1 MW
Total acceptable generation on feeders M14,M15,M16,M17,M18 = 9 MW
Cumulative Generation on station cannot exceed 17 MW
Currently there is no Application received on this Station

Muskoka TS			
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6,M7,M8,M9= 73 MW			
Station Queue Position	M1	M2	M9
1	811 (5 MW)		
2		1292 (0.8 MW)	
3		1639 (9 MW)	
4		1640 (9 MW)	
5		1641 (9 MW)	
6	1807 (10 MW)		
CIA Pending			10310 (10 MW)

Project 1292 has applied to connect to Sundridge North DS

Napanee TS		
Total acceptable generation on feeders M1,M3 = 53 MW		
Total acceptable generation on feeders M2,M4 = 55 MW		
Cumulative Generation on station cannot exceed 67 MW		
	T1	T2
Station Queue Position	M3 - (A)	M2 - (A)
1	1071 (8.5 MW)	
2		1072 (7.5 MW)
3		1073 (8.5 MW)
4	1321 (10 MW)	
5	788 (10 MW)	
6	789 (8 MW)	
7		1505 (8.5 MW)
CIA Ineligible	1523 (10 MW)	
CIA Ineligible	1033 (10 MW)	
CIA Ineligible	430 (9 MW)	
CIA Ineligible	2025 (10 MW)	
8		2139 (4 MW)

Project 1523 has applied to connect to Bath DS

Navan HVDS
Total acceptable generation on feeders F1,F2,F3 = 3 MW
Acceptable generation on feeders F4 = 7 MW
Cumulative Generation on station cannot exceed 4 MW
Currently there is no Application received on this Station

Nelson TS DESN1 (T1&T2)
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6 = 23 MW
Currently there is no Application received on this Station

Nelson TS DESN2 (T3&T4)
Total acceptable generation on feeders M31,M32,M33,M34,M35,M36 = 7 MW
Total acceptable generation on feeders M11,M12,M13,M14,M15,M16 = 8 MW
Cumulative Generation on station cannot exceed 16 MW
Currently there is no Application received on this Station

Nepean TS
Total acceptable generation on feeders M23,M24,M25,M26,M27,M28 = 111.8 MW
For any information or inquiries please contact Ottawa Hydro Inc.

Nestor Falls HVDS
Total acceptable generation on feeders F1, F2 = 2 MW
Currently there is no Application received on this Station

Newington HVDS		
Total acceptable generation on feeders F1, F2= 8.6 MW		
Station Queue Position	F2	F1 - (%)
1	1651 (8.5 MW)	
CIA Ineligible		1757 (10 MW)

Newtonville DS	
Acceptable Generation = 3.4 MW	
Station Queue Position	F2
1	990 (2 MW)

Project 990 has applied to connect to Port Hope TS DESN1

Nipigon HVDS
Total acceptable generation on feeders F1, F2 = 2 MW
Currently there is no Application received on this Station

Norfolk TS					
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6 = 56 MW					
Station Queue Position	**M3 - (A)**	**M5**	**M6 - (%)**	**M2**	**M4 - (%)**
1	1016 (8.5 MW)				
2	1084 (9.9 MW)				
3			1391 (10 MW)		
4		1345 (7.5 MW)			
5				1438 (10 MW)	
6		1439 (10 MW)			
CIA Ineligible	879 (5 MW)				
CIA Ineligible			1403 (10 MW)		
CIA Ineligible			1404 (10 MW)		
CIA Ineligible					2228 (10 MW)

North Bay TS	
Total acceptable generation on feeders M1, M3= 14 MW	
Station Queue Position	**M1**
1	999 (10 MW)

Northbrook HVDS
Total acceptable generation on feeders F1, F2, F3= 7 MW
Currently there is no Application received on this Station

Northcote DS	
Acceptable Generation = 4.2 MW	
Station Queue Position	**F3**
1	645 (1.25 MW)

Project 645 has applied to connect to Cobden TS

Oakville TS #2
Total acceptable generation on feeders M43,M45,M47,M49,M51 = 27 MW
Total acceptable generation on feeders M44,M46,M48,M50,M52 = 23 MW
Cumulative Generation on station cannot exceed 35 MW
Currently there is no Application received on this Station

Orangeville TS DESN 1 - 27.6 kV			
Total acceptable generation on feeders M25, M26 = 53.1 MW			
Station Queue Position	**M26**	**M25**	**M23**
1	365 (1.5 MW)		
2	1888 (9 MW)		
3		1952 (9 MW)	
4			10050 (2337 - 10 MW)
5			10060 (2338 - 10 MW)

Orangeville TS DESN 1 - 44 kV		
Total acceptable generation on feeders M45, M46 = 34 MW		
Station Queue Position	**M45 - (A)**	**M46 -(%)**
1	153c (9 MW)	
2	153d (9 MW)	
3	153e (6 MW)	
4	113 (10 MW)	
CIA Ineligible	869 (8.5 MW)	
CIA Ineligible	1360 (10 MW)	
CIA Ineligible		1715 (10 MW)
CIA Ineligible		1716 (8 MW)

Orangeville TS DESN 2				
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6 = 80 MW				
Station Queue Position	**M4**	**M2 - (A)**	**M3**	**M1**
1	153a (9 MW)			
2	153b (9 MW)			
3		154 (10 MW)		
4	6b (9 MW)			
5		51 (9.9 MW)		
6		116 (10 MW)		
10		10700 (117- 2 MW)		
CIA Ineligible		118 (9.9 MW)		
CIA Ineligible		119 (9.9 MW)		
CIA Ineligible		257 (9 MW)		
CIA Ineligible		258 (9 MW)		
CIA Ineligible		158 (9.9 MW)		
CIA Ineligible		459 (10 MW)		
CIA Ineligible		460 (10 MW)		
CIA Ineligible		461 (10 MW)		
CIA Ineligible		226 (9.9 MW)		
CIA Ineligible		227 (9.9 MW)		
CIA Ineligible		525 (10 MW)		
CIA Ineligible		673 (9.9 MW)		
7			894(10 MW)	
8				1717 (6 MW)
9				1988 (4 MW)

Orillia TS					
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 109 MW					
Station Queue Position	M2	M1	M4 - (A)	M6	M3 - (%)
1	42 (2.812 MW)				
2		638 (1.06 MW)			
3			1494 (10 MW)		
4			1495 (10 MW)		
5			1496 (10 MW)		
6				1527 (10 MW)	
7	1553 (10 MW)				
8	1560 (8.5 MW)				
9	1561 (8.5 MW)				
CIA Ineligible			1860 (10 MW)		
10					1861 (10 MW)
11				2040 (10 MW)	
12					2134 (10 MW)
CIA Ineligible					2135 (10 MW)
13				10690 (8 MW)	

Osgoode DS		
Acceptable generation on T2 = 10.8 MW		
Acceptable generation on T3 = 9.8 MW		
Cumulative generation on T2 & T3 cannot exceed 11.1 MW		
	T2	T3
Station Queue Position	F4	
1	1758 (5 MW)	

Project 1758 has applied to connect to Ottawa Hawthorne TS

Oshawa Thornton TS		
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 101 MW		
Station Queue Position	M3	M8
1	753 (2 MW)	
2		2176 (10 MW)

Oshawa Wilson TS DESN 1		
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 110 MW		
Station Queue Position	M1	M8
1	266 (2.5 MW)	
2		1803 (10 MW)
3		1862 (10 MW)

Oshawa Wilson TS DESN 2				
Total acceptable generation on feeders M11, M12, M13, M14, M15, M16, M17, M18 = 106 MW				
Station Queue Position	M13 - (A)	M12 - (A)	M14	M15
1	790 (9.95 MW)			
2	791 (9.95 MW)			
3		846 (9.95 MW)		
4	703 (10 MW)			
CIA Ineligible	1108 (10 MW)			
5		1114 (10 MW)		
6		1422 (10 MW)		
CIA Ineligible		1423 (10 MW)		
CIA Ineligible		1424 (10 MW)		
CIA Ineligible		1425 (10 MW)		
7			1765 (10 MW)	
8				10250 (20 MW)

Otonabee TS - 44kV		
Total acceptable generation on feeders M25,M27 = 40.2 MW		
Total acceptable generation on feeders M26,M28 = 45.9 MW		
Cumulative Generation on station cannot exceed 52.5 MW		
	B	Y
Station Queue Position	M27 - (%)	M28 - (A)
1		1357 (10 MW)
2		1642 (8.5 MW)
3		1643 (8.5 MW)
CIA Ineligible		1858 (10 MW)
4	2310 (10 MW)	
5	2311 (10 MW)	
6	10420 (2204 - 3 MW)	
7	10430 (2205 - 2.6 MW)	
CIA Ineligible		10010 (2306 - 2 MW)
CIA Ineligible	10030 (2347 - 9 MW)	
CIA Ineligible	10100 (2208 - 2 MW)	
CIA Ineligible	10120 (2209 - 1.4 MW)	

Otonabee TS - 27.6kV
Total acceptable generation on feeders M8,M12 = 5 MW
Total acceptable generation on feeders M9,M11 = 9 MW
Cumulative Generation on station cannot exceed 17 MW
Currently there is no Application received on this Station

Ottawa Hawthorne TS	
Total acceptable generation on feeders M1, M2, M3, M4, M5 = 79 MW	
Station Queue Position	M1 - (A)
1	1310 (10 MW)
2	1311 (10 MW)
3	1758 (5 MW)
CIA Ineligible	1753 (10 MW)
CIA Ineligible	1754 (10 MW)
CIA Ineligible	1857 (10 MW)
CIA Ineligible	1876 (9 MW)

Project 1758 has applied to connect to Osgoode DS

Overbrook TS
Acceptable generation on transformer winding J ("J") = 12 MW
Acceptable generation on transformer winding Q ("Q") = 18 MW
Cumulative Generation on J & Q cannot exceed 30 MW
Currently there is no Application received on this Station

Owen Sound TS					
Total acceptable generation on feeders M21, M22, M23, M24, M25, M26, M28 = 107 MW					
Station Queue Position	M24	M25	M21 - (%)	M26 - (A)	M22 - (%)
Queue Exempt		806 (0.1 MW)			
1	87 (5.1 MW)				
2	241 (9 MW)				
3		161 (9 MW)			
4		1001 (10 MW)			
5		1006 (10 MW)			
6			1085 (9.9 MW)		
7			1086 (9.9 MW)		
8					1087 (9.9 MW)
9				1088 (9.9 MW)	
10				565 (9.9 MW)	
11				567 (9.9 MW)	
CIA Ineligible				568 (9.9 MW)	
CIA Ineligible				569 (9.9 MW)	
CIA Ineligible					1854 (10 MW)
CIA Ineligible			1855 (10 MW)		
CIA Ineligible					1897 (9 MW)

Project 806 has applied to connect to Squire DS

Palermo TS	
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 63.7 MW	
Station Queue Position	M1
1	33 (4 MW)

Palmerston TS			
Total acceptable generation on feeders M1, M2, M3, M4 = 61.5 MW			
Station Queue Position	M2	M1	M3
Queue Exempt	399 (0.25 MW)		
Queue Exempt			893 (0.074 MW)
Queue Exempt			908 (0.074 MW)
Queue Exempt	680 (0.02 MW)		
1	150 (9 MW)		
2		39 (8.8 MW)	
3	175 (10 MW)		
4	688 (1.2 MW)		
5	1255 (10 MW)		
6		1898 (9 MW)	
CIA Ineligible	10220 (10 MW)		
CIA Ineligible	10230 (10 MW)		
7			10330 (9 MW)

Project 399 has applied to connect to Rothsay DS

Project 893 has applied to connect to Tralee DS

Project 908 has applied to connect to Tralee DS

Project 680 has applied to connect to Kenilworth DS

Parry Sound TS		
Total acceptable generation on feeders M1, M2, M3, M4 = 36 MW		
Station Queue Position	M3	M1 - (%)
1	728 (9 MW)	
2		729 (9 MW)
3	730 (9 MW)	
4		731 (9 MW)
CIA Ineligible		732 (9MW)

Pembroke TS			
Total acceptable generation on feeders M1, M2, M3 = 19.5 MW			
Station Queue Position	M2 - (%)	M3 - (%)	M1 - (%)
1	1397 (9.9 MW)		
2	10450 (1398 - 9.324 MW)		
CIA Ineligible	1912 (9.99 MW)		
CIA Ineligible		2010 (10 MW)	
CIA Ineligible			2011 (10 MW)

Petawawa HVDS		
Total acceptable generation on feeders F1,F4,F5 = 5 MW		
Total acceptable generation on feeders F2,F3 = 4 MW		
Cumulative Generation on station cannot exceed 5 MW		
	T1	T2
Station Queue Position	F1 - (%)	
CIA Ineligible	1575 (6 MW)	

Pic HVDS
Total Acceptable Generation on feeders F1, F2 = 8.4 MW
Currently there is no Application received on this Station

Picton TS				
Total acceptable generation on feeders M5, M6, M7, M8= 74.8 MW				
Station Queue Position	M5 - (A)	M6 - (%)	M7 - (%)	M8 - (%)
Queue Exempt	1148 (0.08 MW)			
1	131a (9 MW)			
2	131b (9 MW)			
3		35 (24 MW)		
4	467 (9.9 MW)			
CIA Ineligible	466 (9.9 MW)			
CIA Ineligible	696 (9.2 MW)			
CIA Ineligible	697 (9.2 MW)			
CIA Ineligible	773 (9.9 MW)			
CIA Ineligible	951 (10 MW)			
CIA Ineligible	1019 (10 MW)			
CIA Ineligible	1020 (10 MW)			
CIA Ineligible	1021 (10 MW)			
5			909 (9 MW)	
6				910 (9 MW)
7		1656 (4.5 MW)		
CIA Ineligible		2049 (9 MW)		
CIA Ineligible		1955 (5.5 MW)		
CIA Ineligible			1965 (4.82 MW)	
CIA Ineligible			1968 (10 MW)	
CIA Ineligible				1969 (10 MW)
CIA Ineligible			2026 (10 MW)	
CIA Ineligible		2037 (10 MW)		
CIA Ineligible				2038 (10 MW)
CIA Ineligible		2016 (10 MW)		
CIA Ineligible		2017 (10 MW)		
CIA Ineligible				2018 (4 MW)

Project 1148 has applied to connect to Milford DS

Project 2049 has applied to connect to Milford DS

Plantagenet DS	
Acceptable Generation = 4 MW	
Station Queue Position	F2
Queue Exempt	10600 (1972 - 0.18 MW)

Project 10600 has applied to connect to Longueuil TS

Pleasant TS -DESN1		
Total acceptable generation on feeders M21, M22, M23, M24, M25, M26, M27, M28 = 100 MW		
Station Queue Position	M23	M26
1	2006 (10 MW)	
2		2007 (10 MW)

Pleasant TS - DESN2
Total acceptable generation on feeders M7,M8,M9,M10,M11,M12,M13,M14 = 12 MW
Total acceptable generation on feeders M43, M44, M45, M46, M47, M48 = 26 MW
Cumulative Generation on station cannot exceed 38 MW
Currently there is no Application received on this Station

Pleasant TS - DESN3
Total acceptable generation on feeders M61, M63, M65, M67, M69, M71 = 2 MW
Total acceptable generation on feeders M62, M64, M66, M68, M70, M72 = 3 MW
Cumulative Generation on station cannot exceed 6 MW
Currently there is no Application received on this Station

Port Arthur TS #1					
Total acceptable generation on feeders M2, M3, M4, M5, M6 = 32 MW					
Station Queue Position	M6	M5	M4 - (SC)	M3	M2
1		761 (10 MW)			
CIA Ineligible			762 (10 MW)		
CIA Ineligible				763 (10 MW)	
CIA Ineligible					764 (10 MW)
CIA Ineligible	1015 (10 MW)				

Port Bolster DS	
Acceptable Generation = 3.5 MW	
Station Queue Position	F2
Queue Exempt	1668 (0.100 MW)

Project 1668 has applied to connect to Beaverton TS

Port Colborne TS		
Total Acceptable Generation on feeder M9, M10, M11, M12= 37.1 MW		
Station Queue Position	M11 - (A)	M12
1	755 (9.9 MW)	
2		1774 (9 MW)
3	10240 (1775 - 2.85 MW)	
4		1776 (10 MW)

Port Hope TS DESN1				
Total acceptable generation M15, M16, M17, M18 = 64 MW				
Station Queue Position	M18 - (A)	M16 - (A)	M15 - (%)	M17 - (%)
1	911 (9.9 MW)			
2		914 (9.9 MW)		
3		844 (10 MW)		
4		847 (10 MW)		
5		845 (5 MW)		
CIA Ineligible		884 (9.9 MW)		
6	990 (2 MW)			
7	701 (10 MW)			
8	10820 (702 - 6 MW)			
CIA Ineligible				1029 (10 MW)
CIA Ineligible			2015 (10 MW)	

Project 990 has applied to connect to Newtonville DS

Port Hope TS DESN2	
Total acceptable generation on feeders M1, M2, M3, M4 = 69 MW	
Station Queue Position	M4
1	10640 (2014 - 10 MW)

Preston TS
Total acceptable generation on feeders M23,M25,M27,M29 = 44 MW
Total acceptable generation on feeders M24,M26,M28,M30 = 45.4 MW
Cumulative Generation on station cannot exceed 89.4 MW
For any information or inquiries please contact Cambridge North Dumfries Hydro (CND)

Puslinch HVDS		
Acceptable generation on feeders F1 = 17.2 MW		
Total acceptable generation on feeders F2,F4 = 18.3 MW		
Cumulative Generation on station cannot exceed = 22.3 MW		
	T2	T1
Station Queue Position	F2 - (%)	
1	2250 (10 MW)	
2	2251 (8 MW)	
CIA Ineligible	2101 (10 MW)	

R.H Martindale TS						
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7 = 81.4 MW						
Station Queue Position	M4 - (%)	M5 - (%)	M7 - (A)	M6	M1- (SC)	M2 - (%)
1	745 (1.6 MW)					
2	1390 (9.5 MW)					
3			1506 (10 MW)			
4		644 (10 MW)				
5			1591 (9 MW)			
6			1592 (9 MW)			
CIA Ineligible			1593 (9 MW)			
7				1594 (9 MW)		
8				1595 (9 MW)		
9				1596 (9 MW)		
CIA Ineligible					1606 (9 MW)	
CIA Ineligible					1607 (9 MW)	
CIA Ineligible					1608 (9 MW)	
CIA Ineligible						1609 (9 MW)
CIA Ineligible						1610 (9 MW)
CIA Ineligible						1611 (9 MW)
CIA Ineligible	1665 (9.5 MW)					
CIA Ineligible		2287 (2 MW)				

R.L. Dobbin TS				
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 97.4 MW				
Station Queue Position	M7	M5	M1	M2 - (%)
1	242 (8 MW)			
2		1215 (10 MW)		
3		1109 (10 MW)		
4		1110 (10 MW)		
5			1111 (10 MW)	
6			1112 (10 MW)	
7			1113 (10 MW)	
8			1358 (4 MW)	
9		1359 (4.95 MW)		
10				1412 (10 MW)
11				1428 (10 MW)
CIA Ineligible				1429 (10 MW)
CIA Ineligible				1863 (10 MW)

Ramore TS	
Total acceptable generation on feeders M3, M5 = 8 MW	
Station Queue Position	M5 - (%)
CIA Ineligible	10730 (10 MW)

Reid Corners DS	
Total acceptable generation on feeders F1, F2 = 2 MW	
Station Queue Position	F1
Queue Exempt	10790 (0.250 MW)

Project 10790 has applied to connect to Douglas Point TS

Reddendale DS	
Acceptable Generation = 3.2 MW	
Station Queue Position	F3
1	1635 (0.499 MW)

Project 1635 has applied to connect to Kingston Gardiner TS

Red Lake TS			
Total acceptable generation on feeders M3, M4, M6 = 40 MW			
Station Queue Position	M6	M4	M3
1	1777 (10 MW)		
2		10380 (10 MW)	
3			10580 (10 MW)
4			10680 (10 MW)

Red Rock HVDS
Total acceptable generation on feeders F1, F2, F3 = 4 MW
Currently there is no Application received on this Station

Rexdale TS
Total acceptable generation on feeders M31,M32,M33,M34,M35,M36 = 26 MW
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6 = 19 MW
Cumulative Generation on station cannot exceed 46 MW
Currently there is no Application received on this Station

Riverdale TS
Acceptable generation on bus QZ = 12 MW
Acceptable generation on bus JY = 14 MW
Cumulative Generation on station cannot exceed 27 MW
Currently there is no Application received on this Station

Rockland HVDS
Total acceptable generation on feeders F1, F2, F3 = 8 MW
Currently there is no Application received on this Station

Rockland East HVDS
Total acceptable generation on feeders F4,F5,F6 = 5 MW
Acceptable generation on feeders F1 = 6 MW
Cumulative Generation on station cannot exceed 7 MW
Currently there is no Application received on this Station

Runnymede TS
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6,M7,M8 = 78 MW
Currently there is no Application received on this Station

Russell HVDS
Total acceptable generation on feeders F1,F2,F3,F4 = 1 MW
Currently there is no Application received on this Station

Russell TS
Acceptable generation on bus BY = 13 MW
Acceptable generation on bus QZ = 10 MW
Cumulative Generation on station cannot exceed 23 MW
Currently there is no Application received on this Station

Rothsay DS	
Acceptable Generation = 3.7 MW	
Station Queue Position	F3
Queue Exempt	399 (0.25 MW)

Project 399 has applied to connect to Palmerston TS

Sam Lake HVDS
Total acceptable generation on feeder F1,F2,F3,F4 = 18 MW
Currently there is no Application received on this Station

Sapawe HVDS
Total acceptable generation on feeders F1, F2 = 1 MW
Currently there is no Application received on this Station

Sarnia Wanstead TS			
Total acceptable generation on feeders M2,M4 = 31.4 MW			
Total acceptable generation on feeders M1,M3 = 27.3 MW			
Cumulative Generation on station cannot exceed 36.1 MW			
	T1 & T2	T3	
Station Queue Position	M2 - (%)	M1 - (%) and (A)	M3 - (%)
1		571 (10 MW)	
2		589 (10 MW)	
3	590 (10 MW)		
4			598 (4.8 MW)
CIA Ineligible	634 (9.9 MW)		
CIA Ineligible			671 (10 MW)
CIA Ineligible		801 (9.9 MW)	
CIA Ineligible		824 (10 MW)	
CIA Ineligible			841 (10 MW)
CIA Ineligible	1325 (10 MW)		

Scarboro TS DESN1 (T21&T22)
Total acceptable generation on feeders M21,M23,M25,M27,M29,M31 = 22 MW
Total acceptable generation on feeders M22,M24,M26,M28,M30,M32 = 16 MW
Cumulative Generation on station cannot exceed 39 MW
Currently there is no Application received on this Station

Scarboro TS DESN2 (T23&T24)
Total acceptable generation on feeders M1,M3,M5,M7,M9 = 7 MW
Total acceptable generation on feeders M2,M4,M6,M8,M10 = 18 MW
Cumulative Generation on station cannot exceed 26 MW
Currently there is no Application received on this Station

Schomberg DS DESN2		
Acceptable Generation = 9.3 MW		
Station Queue Position	F3 - (%)	F2
Queue Exempt		10190 (2259 - 0.021 MW)
Queue Exempt	1222 (0.125 MW)	
CIA Ineligible	1847 (10 MW)	

Project 1222 has applied to connect to Kleinburg TS

Project 1847 has applied to connect to Kleinburg TS

Project 10190 has applied to connect to Kleinburg TS

Schreiber Winnipg HVDS
Total acceptable generation on feeders F1, F2 = 4 MW
Currently there is no Application received on this Station

Seaforth TS				
Total acceptable generation on feeders M2, M3, M4, M5 = 33.7 MW				
Station Queue Position	**M4 - (%)**	**M2 - (%)**	**M5 - (%)**	**M3 - (%)**
1		70 (9.2 MW)		
2	71 (9.2 MW)			
3	414 (9.9 MW)			
4			417a (4.9 MW)	
CIA Ineligible			417b (4.9 MW)	
CIA Ineligible				423 (9.9 MW)
CIA Ineligible	425 (9.9 MW)			
CIA Ineligible			428 (9.9 MW)	
CIA Ineligible		422 (9.9 MW)		
CIA Ineligible				426 (9.9 MW)
CIA Ineligible		443 (7.5 MW)		
CIA Ineligible				1899 (9 MW)

Shabaqua HVDS		
Acceptable Generation on feeder M2 = 1.4 MW		
Cumulative generation on feeders M2, F1, F2 cannot exceed 3.9 MW		
	T1	
	12.5 kV	**T2 - 25kV**
Station Queue Position	**F1**	**M2 - (%)**
1	1318 (2.4 MW)	
CIA Ineligible		2055 (2.4 MW)

Sharbot DS
Total acceptable generation on feeders F1, F2, F3 = 3 MW
Currently there is no Application received on this Station

Sheppard TS
Acceptable Generation = 89.3 MW
For any information or inquiries please contact Toronto Hydro

ShiningTree HVDS
Acceptable Generation on M1 = 2 MW
Currently there is no Application received on this Station

Sidney TS				
Total acceptable generation on feeders M1, M3, M4, M5, M6, M7, R8S, R9S = 41 MW				
Station Queue Position	**M7 - (A)**	**M4 - (%)**	**M6 - (%)**	**R9S - (%)**
1	810 (9.9 MW)			
2	1040 (9.9 MW)			
3		1343 (10 MW)		
4	1667 (9.9 MW)			
CIA Ineligible	1703 (10 MW)			
CIA Ineligible			1726 (10 MW)	
CIA Ineligible			1727 (7 MW)	
CIA Ineligible		1850 (10 MW)		
CIA Ineligible				10000 (2256 - 10 MW)

Sioux Narrows HVDS
Total acceptable generation on feeders F1, F2 = 1 MW
Currently there is no Application received on this Station

Slate Falls HVDS
Acceptable Generation on F1 = 1 MW
Currently there is no Application received on this Station

Slater TS
Acceptable generation on bus J1J2 = 18 MW
Acceptable generation on bus Q1Q2 = 19 MW
Acceptable generation on bus B1B2 = 16 MW
Cumulative Generation on station cannot exceed 53 MW
Currently there is no Application received on this Station

Smiths Falls TS						
Total acceptable generation on feeders M21, M22, M23, M24, M25, M26, M27, M28 = 91 MW						
Station Queue Position	**M25**	**M23 - (%)**	**M22 - (A)**	**M28 - (%)**	**M26 - (%)**	**M21 - (%)**
1	1200 (10 MW)					
2	1201 (10 MW)					
3		1204 (10 MW)				
4		1205 (10 MW)				
5			1206 (10 MW)			
6			1207 (10 MW)			
7			1848 (10 MW)			
8		1849 (10 MW)				
9	1926 (10 MW)					
CIA Ineligible			1927 (10 MW)			
CIA Ineligible		1928 (10 MW)				
CIA Ineligible				2020 (10 MW)		
CIA Ineligible					2096 (5 MW)	
CIA Ineligible					2103 (10 MW)	
CIA Ineligible						1995 (5 MW)

Smooth Rock Falls HVDS
Acceptable generation on feeders F1 = 6 MW
Acceptable generation on feeders F2 = 6 MW
Cumulative Generation on station cannot exceed 6 MW
Currently there is no Application received on this Station

South Gloucester HVDS
Total acceptable generation on F1, F2 = 4 MW
Currently there is no Application received on this Station

Southmarch TS			
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6 = 70 MW			
Station Queue Position	M5 - (A)	M6	M3
1	217 (6.4 MW)		
2		1712 (10 MW)	
3		1713 (10 MW)	
4		1714 (10 MW)	
5	10370 (1834 - 5.5 MW)		
6	1871 (10 MW)		
CIA Ineligible	1891 (9 MW)		
7			10630 (2052 - 10 MW)
CIA Pending			10780 (0.500 MW)

Project 217 has applied to connect to Alexander DS

Project 10370 has applied to connect to Alexander DS

Project 1891 has applied to connect to Alexander DS

Project 10780 has applied to connect to Munster DS (Please contact Hydro Ottawa for any Inquiries)

Sowerby HVDS
Total acceptable generation on feeders F1, F2 = 3 MW
Currently there is no Application received on this Station

Spanish HVDS	
Total acceptable generation on feeders F1, F2 = 7 MW	
Station Queue	F2
1	162 (1.1 MW)

Spencerville DS	
Acceptable Generation = 1.3 MW	
Station Queue Position	F2
1	836 (0.498 MW)

Springvale DS	
Acceptable Generation = 6.8 MW	
Station Queue Position	F1
CIA pending	505 (2 MW)

Project 505 has applied to connect to Forest Jura HVDS

Squire DS	
Acceptable Generation = 3.6 MW	
Station Queue Position	F3
Queue Exempt	806 (0.1 MW)

Project 806 has applied to connect to Owen Sound TS

St. Andrews TS
Total acceptable generation on feeders M9, M10, M11, M12, M13, M14, M15, M16 = 84 MW
For any information or inquiries please contact Blue Water Power Distribution Corporation

St. Isidore TS				
Total acceptable generation on feeders M1, M2, M3, M4 = 39.9 MW				
Station Queue Position	M4	M2 - (%)	M1- (%)	M3 - (%)
1	1074 (7.5 MW)			
2		891 (4.24 MW)		
3			1211 (10 MW)	
4		1212 (10 MW)		
5	1214 (8 MW)			
CIA Ineligible				1213 (10 MW)
CIA Ineligible			10490 (820 - 0.5 MW)	
CIA Ineligible		1461 (0.4999 MW)		
CIA Ineligible		1587 (4 MW)		
CIA Ineligible		10520 (1369 - 0.065 MW)		
CIA Ineligible				10540 (1371-0.18 MW)
CIA Ineligible		10550 (1374 - 0.1 MW)		
CIA Ineligible		10760 (0.250 MW)		

Project 1074 has applied to connect to Glengarry DS

Project 1461 has applied to connect to Crysler DS

Project 10520 has applied to connect to Crysler DS

Project 10540 has applied to connect to McCrimmon DS

Project 10550 has applied to connect to Crysler DS

Project 10760 has applied to connect to Crysler DS

St. Lawrence TS		
Total acceptable generation on M24, M25, M26, M27, M28 = 74 MW		
Station Queue Position	M26 - (A)	M25
1	1576 (9.9 MW)	
2	1577 (9.9 MW)	
3	1690 (9.9 MW)	
CIA Ineligible	1864 (10 MW)	
CIA Ineligible	1865 (10 MW)	
CIA Ineligible	1905 (10 MW)	
CIA Ineligible	1906 (5 MW)	
CIA Ineligible	1913 (9.99 MW)	
CIA Pending		10300 (10 MW)

St. Marys TS	
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6 = 29 MW	
Station Queue Position	M6
1	1155 (10 MW)

St. Thomas TS - DESN1
Total acceptable generation on feeders M3, M5 = 15 MW
Currently there is no Application received on this Station

St. Thomas TS - DESN2	
Total acceptable generation on feeders M10 = 21 MW	
Station Queue Position	M10 - (A)
1	1014 (10 MW)
2	1169 (10 MW)
CIA Ineligible	1170 (10 MW)
CIA Ineligible	1171 (10 MW)
CIA Ineligible	1078 (10 MW)
CIA Ineligible	1079 (10 MW)
CIA Ineligible	905 (10 MW)
CIA Ineligible	1147 (10 MW)

St. Thomas Edgeware TS						
Total acceptable generation on feeders M1,M3,M5,M7 = 48.2 MW						
Total acceptable generation feeders M2,M4,M6,M8,M10 = 53.3 MW						
Cumulative Generation on station cannot exceed 101.6 MW						
	B			Y		
Station Queue Position	M3 - (%)	M5 - (%)	M1	M4 - (A)	M2	M10
1				367 (9.9 MW)		
2	812 (9.9 MW)					
3	813 (9.9 MW)					
4					953 (10 MW)	
5					1048 (10 MW)	
6				1134 (9.9 MW)		
7			1181 (10 MW)			
8			1182 (10 MW)			
9		1254 (8.4 MW)				
10						1158 (7 MW)
11						1159 (6 MW)
CIA Ineligible				1689 (3.2 MW)		
CIA Ineligible	2000 (3.6 MW)					
CIA Ineligible		2071 (10 MW)				
CIA Ineligible		2072 (10 MW)				

Stanley TS
Total acceptable generation on feeders M31,M32,M33,M41,M42,M43 = 11 MW
Total acceptable generation on feeders M1,M2,M3,M4,M5,M6 = 7 MW
Cumulative Generation on station cannot exceed 19 MW
Currently there is no Application received on this Station

Stardale DS		
Acceptable Generation = 3.8 MW		
Station Queue Position	F3 - (A)	F2
Queue Exempt	390 (0.18 MW)	
Queue Exempt	391 (0.10 MW)	
Queue Exempt	1573 (0.18 MW)	
Queue Exempt		10510 (0.250 MW)

Project 390 has applied to connect to Longueuil TS

Project 391 has applied to connect to Longueuil TS

Project 10510 has applied to connect to Longueuil TS

Project 1573 has applied to connect to Longueuil TS

Stayner TS			
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 80.2 MW			
Station Queue Position	M2 - (A)	M4 - (A)	M1 - (%)
1	508 (9.9 MW)		
2	472 (10 MW)		
3	944 (10 MW)		
4	945 (8 MW)		
CIA Ineligible	1164 (10 MW)		
CIA Ineligible	1165 (10 MW)		
5		1166 (10 MW)	
6		1167 (10 MW)	
7		1168 (10 MW)	
CIA Ineligible	925 (10 MW)		
CIA Ineligible		929 (10 MW)	
8			1779 (10 MW)
CIA Ineligible			1780 (10 MW)
CIA Ineligible		1869 (10 MW)	

Stewartville TS		
Total acceptable generation on feeders M1, M3, M4 = 27.9 MW		
Station Queue	M1 - (%)	M3 - (%)
1		1693 (9.99 MW)
2		1694 (9.99 MW)
3		1695 (7.695 MW)
CIA Ineligible	1696 (9.9 MW)	
CIA Ineligible	1697 (9.9 MW)	
CIA Ineligible	1698 (9.9 MW)	
CIA Ineligible		1908 (9.99 MW)
CIA Ineligible	1910 (9.99 MW)	
CIA Ineligible		1999 (3.6 MW)
CIA Ineligible		1974 (1.5 MW)
CIA Ineligible		2120 (1.213 MW)
CIA Ineligible		2121 (1.315 MW)
CIA Ineligible		2122 (2 MW)

Stirton TS
Total acceptable generation on feeders M71,M72,M75,M76,M81,M82,M83,M84,M85, M86 = 12 MW
Total acceptable generation on feeders M51,M52,M53,M54,M61,M62,M63,M64 = 2 MW
Cumulative Generation on station cannot exceed 12 MW
Currently there is no Application received on this Station

Stirling DS	
Acceptable generation = 4 MW	
Station Queue Position	F3
1	837 (0.498 MW)

Project 837 has applied to connect to Belleville TS

Strachan TS DESN1
Acceptable generation on transformer winding A5/A6 ("A5/A6") = 9 MW
Acceptable generation on transformer winding A7/A8 ("A7/A8") = 8 MW
Cumulative Generation on A5/A6 & A7/A8 cannot exceed 20 MW
Currently there is no Application received on this Station

Strachan TS DESN2
Acceptable generation on transformer winding A1/A2 ("A1/A2") = 9 MW
Acceptable generation on transformer winding A3/A4 ("A3/A4") = 9 MW
Cumulative Generation on A1/A2 & A3/A4 cannot exceed 22 MW
Currently there is no Application received on this Station

Stratford TS		
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 78 MW		
Station Queue Position	M6 - (A)	M7 - (A)
1	1153 (10 MW)	
2	1154 (10 MW)	
CIA Ineligible	1602 (10 MW)	
CIA Ineligible	1603 (10 MW)	
CIA Ineligible	1915 (10 MW)	
3		2031 (10 MW)
4		2073 (10 MW)
CIA Ineligible		2074 (10 MW)

Strathroy TS		
Total acceptable generation on feeders M1, M2, M3, M4 = 39 MW		
Station Queue	M1 - (A)	M3 - (%)
1	1042 (9 MW)	
2	1043 (9 MW)	
3		1044 (9 MW)
4	892 (2 MW)	
CIA Ineligible	1296 (10 MW)	
CIA Ineligible	1297 (10 MW)	
CIA Ineligible	1298 (10 MW)	
5		1282 (10 MW)
CIA Ineligible		1283 (10 MW)
CIA Ineligible	920 (10 MW)	
CIA Ineligible	921 (10 MW)	
CIA Ineligible		922 (10 MW)

Striker HVDS		
Acceptable generation on feeder F1 = 9.4 MW		
Acceptable generation on feeder F2 = 8 MW		
Cumulative Acceptable Generation cannot exceed 11 MW		
Station Queue Position	F1 - (%)	F2 - (%)
1	519 (9.4 MW)	
CIA Ineligible		866 (7.5 MW)

Sundridge North DS	
Acceptable Generation = 4.6 MW	
Station Queue Position	F2
1	1292 (0.8 MW)

Project 1292 has applied to connect to Muskoka TS

Talbot TS DESN1 (T1&T2)
Total acceptable generation on feeders M11, M12, M13, M14, M21, M22, M23, M25 = 63 MW
For any information or inquiries please contact London Hydro

Talbot TS DESN2 (T3&T4)
Total acceptable generation on feeders M41,M42,M43,M46,M47,M48 = 19 MW
Total acceptable generation on feeders M51,M52,M53,M54,M55,M56 = 19 MW
Cumulative Generation on station cannot exceed 40 MW
For any information or inquiries please contact London Hydro

Temagami HVDS
Total acceptable generation on feeders F1, F2 = 3 MW
Currently there is no Application received on this Station

Terauley TS DESN1 (T1&T4)
Acceptable generation on transformer winding A1/A2 ("A1/A2") = 20 MW
Acceptable generation on transformer winding A7/A8 ("A7/A8") = 15 MW
Cumulative Generation on A1/A2 & A7/A8 cannot exceed 36 MW
Currently there is no Application received on this Station

Terauley TS DESN2 (T2&T3)
Acceptable generation on transformer winding A3/A4 ("A3/A4") = 15 MW
Acceptable generation on transformer winding A5/A6 ("A5/A6") = 21 MW
Cumulative Generation on A3/A4 & A5/A6 cannot exceed = 38 MW
Currently there is no Application received on this Station

Thorold TS
Total acceptable generation on feeders M1,M2,M3 = 6 MW
Currently there is no Application received on this Station

Tilbury TS	
Acceptable Generation on M1 = 5.1 MW	
Station Queue Position	M1 - (%)
1	1477 (5 MW)
CIA Ineligible	1294 (9.9 MW)
CIA Ineligible	1295 (9.9 MW)

Tilbury West HVDS		
Acceptable generation on feeders F1 = 15.9 MW		
Acceptable generation on feeders F2 = 16.3 MW		
Cumulative Generation on station cannot exceed 20.2 MW		
	T1	T2
Station Queue Position	F1 - (%)	F2 - (%)
Queue Exempt	1468 (0.5 MW)	
1		7 (10 MW)
2	221 (9 MW)	
CIA Ineligible		376 (9.9 MW)
CIA Ineligible		494 (9.9 MW)
CIA Ineligible		495 (9.9 MW)
CIA Ineligible		573 (9 MW)
CIA Ineligible		574 (9 MW)
CIA Ineligible	2115 (0.9 MW)	

Tillsonburg DS	
Acceptable Generation = 2.7 MW	
Station Queue Position	F2
Queue Exempt	165 (0.064 MW)

Project 165 has applied to connect to Tillsonburg TS

Tillsonburg TS					
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M10 = 76.3 MW					
Station Queue Position	M2 - (A)	M4 - (A)	M10 - (%)	M3	M1
Queue Exempt	165 (0.064 MW)				
1	281 (9.9 MW)				
2	282 (9.9 MW)				
3			667 (9.9 MW)		
4		668 (9.9 MW)			
CIA Ineligible	669 (9.9 MW)				
CIA Ineligible	735 (9.9 MW)				
5		511 (10 MW)			
CIA Ineligible	989 (3.3 MW)				
6				881 (10 MW)	
7					693 (10 MW)
8			1066 (6.7 MW)		
CIA Ineligible			1177 (9.9 MW)		
CIA Ineligible		2304 (10 MW)			

Project 165 has applied to connect to Tillsonburg DS

Timmins TS			
Total acceptable generation on feeders M5, M6, M7, M8, M9, M10, M11 = 60 MW			
Station Queue	M7	M8	M11
1		251 (15 MW)	
2	250 (5.5 MW)		
3	1870 (10 MW)		
4			2200 (10 MW)
5			2201 (6 MW)

Tomken TS DESN1 (T1&T2)
Total acceptable generation no feeders M1,M2,M3,M4,M5,M6,M7,M8 = 102 MW
Currently there is no Application received on this Station

Tomken TS DESN2 (T3&T4)
Total acceptable generation on feeders M23,M24,M25,M26,M27,M28,M29,M30 = 104 MW
Currently there is no Application received on this Station

Toronto Main TS
Acceptable generation on transformer winding A1/A2 ("A1/A2") = 10 MW
Acceptable generation on transformer winding A3/A4 ("A3/A4") = 14 MW
Cumulative Generation on station cannot exceed 23 MW
Currently there is no Application received on this Station

Tralee DS	
Acceptable Generation = 4 MW	
Station Queue Position	F3
Queue Exempt	893 (0.074 MW)
Queue Exempt	908 (0.074 MW)

Project 893 has applied to connect to Palmerston TS

Project 908 has applied to connect to Palmerston TS

Trout Creek DS	
Acceptable Generation = 4.5 MW	
Station Queue Position	F1
1	10020 (2341 - 0.8 MW)

Project 10020 has applied to connect to Trout Lake TS

Trout Lake TS				
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 91 MW				
Station Queue Position	M7 - (A)	M8 - (A)	M3	M5
1	26 (10 MW)			
2	373 (10 MW)			
CIA Ineligible	675 (9 MW)			
3				1666 (1.6 MW)
4		962 (10 MW)		
5		966 (10 MW)		
6		967 (10 MW)		
CIA Ineligible	484 (10 MW)			
CIA Ineligible	485 (10 MW)			
7				2193 (9 MW)
8			1636 (9 MW)	
9			1637 (9 MW)	
10			1638 (9 MW)	
CIA Ineligible	2309 (10 MW)			
11	10020 (2341 - 0.8 MW)			

Project 10020 has applied to connect to Trout Creek DS

Valora HVDS
Acceptable Generation on F1 = 1 MW
Currently there is no Application received on this Station

Vansickle TS
Total acceptable generation on feeders M41, M42, M43, M51, M52, M53 = 17 MW
For any information or inquiries please contact Horizon Utilities Corporation

Vermilion Bay HVDS
Total acceptable generation on feeders F1, F2, F3 = 3 MW
Currently there is no Application received on this Station

Verner HVDS	
Total acceptable generation on feeders F1, F2, F3 = 6 MW	
Station Queue Position	F2 - (%)
CIA Ineligible	1646 (9.99 MW)

Vineland HVDS
Total Acceptable Generation on feeders F1, F2 = 14 MW
For any information or inquiries please contact Niagara Peninsula Energy Inc.

Wallace TS			
Acceptable generation on feeders M1 = 27 MW			
Total acceptable generation on feeders M4,M6 = 32.3 MW			
Cumulative Generation on station cannot exceed 33.4 MW			
	T3	T4	
Station Queue Position	M1 - (%)	M6	M4 - (%)
1	31 (0.6 MW)		
2		585 (9 MW)	
3		656 (9 MW)	
4		695 (9 MW)	
5			549 (3.95 MW)
CIA Ineligible	734 (10 MW)		
CIA Ineligible	716 (10 MW)		
CIA Ineligible			1132 (9 MW)
CIA Ineligible			1133 (9 MW)

Wallaceburg TS		
Total acceptable generation on feeders M1, M2, M3, M5, M6 = 41 MW		
Station Queue Position	M3 - (A)	M1 - (A)
1	24 (10 MW)	
2	437 (9 MW)	
3	438 (1.5 MW)	
CIA Ineligible	209 (10 MW)	
CIA Ineligible	237 (9 MW)	
CIA Ineligible	238 (9 MW)	
4		770 (9.9 MW)
CIA Ineligible	875 (9 MW)	
CIA Ineligible	876 (9 MW)	
5		1866 (10 MW)
CIA Ineligible		1902 (9 MW)

Walker TS
Total Acceptable Generation on feeders M1, M2, M3, M5, M6 = 39.4 MW
For any information or inquiries please contact EnWin Utilities

Warden TS
Total acceptable generation on feeders M21,M23,M25,M27,M29,M31 = 17 MW
Total acceptable generation on feeders M24,M26,M28,M30,M32 = 18 MW
Cumulative Generation on station cannot exceed 37 MW
Currently there is no Application received on this Station

Warren HVDS
Total acceptable generation on feeders F1,F2 = 4 MW
Total acceptable generation on feeders F3,F4 = 5 MW
Cumulative Generation on station cannot exceed 5 MW
Currently there is no Application received on this Station

Waubaushene TS			
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7 = 60 MW			
Station Queue Position	M7	M5 - (%)	M1
1	123 (9 MW)		
2	1874 (10 MW)		
3	1900 (9 MW)		
4		2066 (10 MW)	
5		2141 (10 MW)	
6			10620 (2237 - 10 MW)
CIA Ineligible		2100 (10 MW)	

Wendover HVDS		
Acceptable generation on feeders F1 = 14 MW		
Acceptable generation on feeders F3 = 15 MW		
Cumulative Generation on station cannot exceed 14 MW		
	T2	T1
Station Queue Position	F3 - (%)	F1 - (%)
1	65 (1.266 MW)	
2		1062 (2 MW)
3	1759 (10 MW)	
CIA Ineligible		1760 (10 MW)
CIA Ineligible	1872 (10 MW)	
CIA Ineligible		1903 (9 MW)

Weston Lake HVDS
Total acceptable generation on feeders F1, F2 = 6 MW
Currently there is no Application received on this Station

Wharncliffe HVDS	
Total acceptable generation on F1, F2= 3 MW	
Station Queue Position	F2
Queue Exempt	400 (0.13 MW)

Whitby TS - DESN1
Total acceptable generation on M43, M44, M45, M46, M47, M48 = 1 MW
Total acceptable generation on M5, M6, M7, M8 = 14 MW
Currently there is no Application received on this Station

Whitby TS - DESN2			
Total acceptable generation on feeders M21, M22, M23, M24, M25, M26, M27, M28 = 119 MW			
Station Queue Position	M23	M24	M21
Queue Exempt			2293 (0.5 MW)
1	1394 (18.75 MW)		
2		1393 (9.9 MW)	

Whitefish HVDS
Total acceptable generation on feeders F1, F2 = 5 MW
Currently there is no Application received on this Station

White River HVDS	
Acceptable Generation = 0 MW	
Station Queue Position	F3 - (%)
CIA Sent	74 (9.9 MW)

Wilhaven HVDS		
Total acceptable generation on F1,F2,F3 = 20 MW		
Total acceptable generation on F4,F5 = 21 MW		
Cumulative Generation on station cannot exceed 25 MW		
	T2	T1
Station Queue Position	F3	
1	1761 (10 MW)	

Windsor Lauzon TS DESN 1 (T5/T6)		
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 65 MW		
Station Queue Position	M4 - (A)	M2
1	1067 (10 MW)	
2	1068 (10 MW)	
CIA Ineligible	1075 (10 MW)	
CIA Ineligible	1094 (9.9 MW)	
CIA Ineligible	1095 (9.9 MW)	
CIA Ineligible	621 (10 MW)	
CIA Ineligible	800 (10 MW)	
CIA Ineligible	1125 (10 MW)	
CIA Ineligible	1176 (10 MW)	
CIA Ineligible	622 (10 MW)	
3		2147 (9.9 MW)

Windsor Lauzon TS DESN 2 (T7/T8)						
Total acceptable generation on feeders M23, M24, M25, M26, M27, M28, M29 = 63 MW						
Station Queue Position	**M24 - (A)**	**M27 - (%)**	**M29 - (A)**	**M28 - (%)**	**M26 - (%)**	**M23 - (%)**
1	88 (10 MW)					
2			89 (10 MW)			
3	897 (9.9 MW)					
4				822 (10 MW)		
5			960 (1 MW)			
6					961 (1 MW)	
7			995 (10 MW)			
CIA Ineligible	996 (10 MW)					
8		1036 (9.9 MW)				
CIA Ineligible				1037 (9.9 MW)		
CIA Ineligible				1063 (9.9 MW)		
CIA Ineligible				1064 (9.9 MW)		
CIA Ineligible			928 (9.9 MW)			
CIA Ineligible						1184 (10 MW)
CIA Ineligible						1185 (10 MW)
CIA Ineligible						1186 (10 MW)
CIA Ineligible					1478 (3 MW)	
CIA Ineligible					1491 (4 MW)	
CIA Ineligible		1867 (10 MW)				
CIA Ineligible					2012 (10 MW)	
CIA Ineligible			2013 (10 MW)			

Windsor Malden TS					
Total acceptable generation on feeders M1,M3,M5,M7,M9,M11 = 52 MW					
Total acceptable generation on feeders M2,M4,M6,M8,M10,M12= 50 MW					
Cumulative Generation on station cannot exceed 102 MW					
	B		Y		
Station Queue Position	**M7 (A)**	**M11 (A)**	**M12 - (A)**	**M10 - (A)**	**M8 - (%)**
1			90 (10 MW)		
2			582 (9.9 MW)		
CIA Ineligible			583 (9.9 MW)		
CIA Ineligible			877 (9.9 MW)		
CIA Ineligible			878 (9.9 MW)		
CIA Ineligible			662 (9.9 MW)		
CIA Ineligible			778 (6.3 MW)		
3	1096 (9.9 MW)				
4	1097 (9.9 MW)				
5		1098 (9.9 MW)			
6		1099 (9.9 MW)			
7				1188 (9.9 MW)	
8				1189 (9.9 MW)	
9					1190 (9.9 MW)
CIA Ineligible		1238 (10 MW)			
CIA Ineligible		1239 (10 MW)			
CIA Ineligible		1240 (10 MW)			
10	477 (0.6 MW)				
CIA Ineligible	1241 (10 MW)				
CIA Ineligible	1242 (10 MW)				
CIA Ineligible	1243 (10 MW)				
CIA Ineligible				1244 (10 MW)	
CIA Ineligible				1245 (10 MW)	
CIA Ineligible				1246 (10 MW)	
CIA Ineligible					1252 (10 MW)
CIA Ineligible					1253 (10 MW)

Wingham TS				
Total acceptable generation on feeders M3, M4, M5, M6 = 58 MW				
Station Queue Position	**M6 - (%)**	**M3 - (A)**	**M5 - (%)**	**M4 - (%)**
1		91a (9 MW)		
2		94 (9 MW)		
3	92 (9 MW)			
4	93 (9 MW)			
5		99 (10 MW)		
6			98 (10 MW)	
CIA Ineligible	100 (10 MW)			
CIA Ineligible	101 (10 MW)			
CIA Ineligible			102 (10 MW)	
CIA Ineligible			103 (10 MW)	
CIA Ineligible			104 (10 MW)	
CIA Ineligible			105 (10 MW)	
CIA Ineligible		106 (10 MW)		
CIA Ineligible				107 (10 MW)
CIA Ineligible				108 (10 MW)
CIA Ineligible			84 (10 MW)	
CIA Ineligible			85 (10 MW)	
CIA Ineligible		91b (1 MW)		
CIA Ineligible	92b (1 MW)			
CIA Ineligible	93b (1 MW)			
CIA Ineligible		94b (1 MW)		
CIA Ineligible			476 (10 MW)	
CIA Ineligible			738 (10 MW)	
CIA Ineligible				1901 (9 MW)

Winona TS
Total acceptable generation on feeders M11, M12, M13, M14, M15, M16 = 58.6 MW
For any information or inquiries please contact Horizon Utilities Corporation

Wolverton HVDS		
Acceptable generation on feeders F1 = 18 MW		
Acceptable generation on F2 = 16.2 MW		
Cumulative generation on station cannot exceed 20.7 MW		
	T1	T2
Station Queue Position	**F1**	**F2**
1	919 (9.85 MW)	
2	1548 (8.15 MW)	

Wonderland TS		
Total acceptable generation on feeders M1, M2, M3, M4, M5, M6, M7, M8 = 70.8 MW		
Station Queue Position	**M2 - (A)**	**M1**
1	1363 (10 MW)	
2	1364 (10 MW)	
CIA Ineligible	1875 (10 MW)	
3		2056 (7.125 MW)

WoodroffeTS
Acceptable generation on transformer T2 = 21 MW
Acceptable generation on transformer T4 = 21 MW
Cumulative Generation on T2 & T4 cannot exceed 27 MW
Currently there is no Application received on this Station

Woodstock TS				
Total acceptable generation on feeders M3, M4, M6, M7, M8, M9, M10 = 70 MW				
Station Queue Position	**M9 - (A)**	**M4 - (A)**	**M6 - (A)**	**M10 - (%)**
Queue Exempt	616 (0.113 MW)			
1		882 (10 MW)		
2		1546 (10 MW)		
CIA Ineligible		1547 (10 MW)		
3	1622 (9.3 MW)			
4	1156 (10 MW)			
CIA Ineligible	1449 (10 MW)			
CIA Ineligible	1450 (10 MW)			
CIA Ineligible	1653 (10 MW)			
CIA Ineligible	1654 (10 MW)			
CIA Ineligible	1699 (10 MW)			
CIA Ineligible	1700 (10 MW)			
5			1718 (10 MW)	
6			1781 (10 MW)	
CIA Ineligible	1873 (10 MW)			
CIA Ineligible	1896 (9 MW)			
CIA Ineligible			2161 (9 MW)	
7				2162 (9 MW)
CIA Ineligible				2163 (9 MW)
CIA Ineligible			2164 (9 MW)	

Project 616 has applied to connect to Woodstock Zorra DS

Woodstock Zorra DS	
Acceptable generation = 3.9 MW	
Station Queue Position	**F2**
Queue Exempt	616 (0.113 MW)

Project 616 has applied to connect to Woodstock TS

School Energy Coalition (SEC) INTERROGATORY #7 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 1

Please confirm that the following table correctly summarizes the amounts that the Applicant proposes should be funded by its distribution customers in the current GEGEA plan:

	2010		2011		2012-2014		Totals	
($million)	OM&A	Capital	OM&A	Capital	OM&A	Capital	OM&A	Capital
Renewable Generation Connections	3	0	3	0	10	0	**16**	**0**
Expansion Work	0	12	0	25	0	90	**0**	**127**
Renewable Enabling Improvements	0	4	0	8	0	30	**0**	**42**
Smart Grid	10	30	10	62	45	250	**65**	**342**
TOTALS	**13**	**46**	**13**	**95**	**55**	**370**	**81**	**511**

Response

The first row should be labeled "Renewable Generation Development OM&A", otherwise Hydro One confirms the information in the table is correct.

In confirming this information Hydro One notes the following corrections to the information provided in its Green Energy Plan:

- The tables on page 1 and page 24 should read $770, not $780, for the 2012-2014 "Externally Funded Costs"
- The table on page 1 should read $370, not $360, for the 2012-2014 "Net Costs in the Plan funded by Hydro One Customers"
- The table on page 24 should read $120, not $110 for the 2012-2014 "Net Capital Investment"

School Energy Coalition (SEC) INTERROGATORY #8 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 1

Please confirm that the total spending proposed in the current GEGEA plan is $181 million or more of OM&A and $1.736 billion in capital, in each case over a five year period commencing in the test year.

Response

Yes, that is confirmed.

School Energy Coalition (SEC) INTERROGATORY #9 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 1

Please provide a table showing the Applicant's overall personnel spending (i.e. all personnel costs expected to be incurred by the Applicant in the historical year, the bridge year, and the test year of all types, whether GEGEA related or otherwise), broken down as follows:

(a) Transmission OM&A:
(b) Transmission capital;
(c) Distribution OM&A ratepayer funded;
(d) Distribution capital ratepayer funded;
(e) Distribution OM&A generator funded;
(f) Distribution capital generator funded;
(g) Distribution OM&A externally funded (Reg. 330/09);
(h) Distribution capital externally funded (Reg. 330/09);
(i) Distribution OM&A externally funded (OPA);
(j) Distribution capital externally funded (OPA);
(k) Distribution OM&A all other;
(l) Distribution capital all other.

Please reconcile the totals to the total OM&A and capital spending reported, forecast or proposed in this Application in its various components, and the current approved transmission budget of the Applicant. If there are substantial overall increases year to year in the overall spending, please provide a description of the Applicant's strategy for handling the growth in personnel and/or personnel costs.

Response

As a result of the work based approach that Hydro One takes to its planning, reporting and accounting for work we cannot provide this breakdown. Hydro One uses a Standard costing approach (Refer to Exhibit C, Tab 1, Schedule 4) to attribute labour costs to work.

Please refer to Exhibit C1, Tab 2, Schedule 5 for a high level break out of the labour component in OM&A and Capital for the Distribution Business.

School Energy Coalition (SEC) INTERROGATORY #10 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 1

Please provide a table, similar to the one in the last question, with the same breakdown and for the same years, but showing FTEs rather than dollar amounts. If it is possible to break the FTEs down into personnel categories (using the Board's standard classifications), please do so.

Response

Please refer to Exhibit H, Tab 10, Schedule 9.

School Energy Coalition (SEC) INTERROGATORY #11 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 4

Please provide the rationale behind the Applicant's decision not to invest directly in renewable generation. If the Applicant has obtained or prepared any studies, analyses, or other such documents related to that decision, please provide them.

Response

Prior to the introduction of the *Green Energy and Green Economy Act, 2009*, according to Section 50.4 of the *Electricity Act, 1998* Distributors were not allowed to engage in any activities other than distributing electricity.

Section 71.3 of the *OEB Act, 1998* came into effect on September 9, 2009, allowing Distributors to own and operate a renewable energy generation facility under 10MW. Given this is such a recent development, Hydro One Distribution has not yet had the opportunity to consider investing directly in renewable generation and currently it is not organized and structured to handle this type of investment.

School Energy Coalition (SEC) INTERROGATORY #12 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 4

Please provide a copy of the CDM budget assumed to be spent in the test year that underpins the current load forecast. If the load forecast is not based on any forecast of CDM spending by the Applicant in the test year, please describe in what way the load forecast takes the Applicant's CDM activities into account.

Response

For CDM budget assumed for 2010 and 2011, please see Exhibit H, Tab 4, Schedule 5 and Schedule 6.

The load forecast is not based on a forecast of CDM spending by Hydro One. Please refer to Exhibit A, Tab 14, Schedule 4, Section 2.6, pages 7-9 and Exhibit H, Tab 12, Schedule 2. Hydro One Distribution is taking a conservative approach in accounting for CDM impacts and CDM results achieved to date show that the impact of CDM savings on Hydro One Distribution has exceeded the CDM forecast.

School Energy Coalition (SEC) INTERROGATORY #13 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 7

Please confirm that the April 2009 figures in the table are cumulative to the end of April, and include all of the prior data in the table. Please provide, with respect to each of the cells in the table that has a number of CIAs for April, 2009, the MW of generation that number of CIAs represented, broken down by generation source (e.g. wind, solar, biomass, other). Please estimate the MW of projects contained in the 127 agreements completed that are expected to proceed under the RESOP program.

Response

Yes. The April 2009 figures in the table are cumulative to the end of April 2009 and include all of the prior data in the table. The 869 CIAs include 184 reworks so there were actually 685 separate Projects, which cumulatively have 5,690 MW.

See the response at Exhibit H, Tab 3, Schedule 63, part a) for a breakdown by resource and MW.

See the response at Exhibit H, Tab 3, Schedule 63, part d) for the MW associated with the 127 projects with completed connection agreements.

School Energy Coalition (SEC) INTERROGATORY #14 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, Page 8

Please describe the methodology that Hydro One plans to use to assess the probability of completion of projects, and/or the planning risks associated with the possibility that projects will not proceed.

Response

Going forward, Hydro One expects that almost all generators that apply for a Connection Impact Assessment will proceed to connection given that renewable generation projects must apply through the Feed-In Tariff (FIT) program and the Distribution System Code was recently amended to ensure more rigour around the generation connections process. Both the FIT program and the DSC amendments require significant financial security deposits and/or fees that will act as a deterrent to projects not proceeding.

School Energy Coalition (SEC) INTERROGATORY #15 List 1

Interrogatory

Cost of Capital

Reference: Development Capital: GEGEA and Smart Grid projects

(a) For each of the GEGEA –related development capital projects (which appear to be all of D1, D27, D28, D29, D30, D31, D32, D33 and D35 (smart grid)), please provide any business case, net present value analysis or other internal analysis used to support the project.

Response

Detailed business cases including net present value of expenditures will not be developed for distribution generation related capital projects until the information on participation in the FIT program firms up.

With respect to Smart Grid, scenarios to support the GEGEA's direction and related business requirements have been developed and included the RFP (see Exhibit H, Tab 12, Schedule 46) for piloting in the Smart Zone. Business cases and net present value analysis will be completed once the outcome of the RFP and Smart Zone pilot is known.

School Energy Coalition (SEC) INTERROGATORY #16 List 1

Interrogatory

Cost of Capital

Reference: Exhibit D1/Tab 3/Schedule 3 Generation Connections
Exhibit A/Tab 14/Schedule 2, page 10, 12

(a) Please provide further detail as to how the forecasted number of generation connections was determined for 2010 and 2011. The evidence states only that the forecast was based on the experience under the RESOP and "makes provision for demand under the FIT program" but does not explain what that allowance is, how it was determined, or what assumptions were made.

(b)

(i) Please provide a description of which regions are considered high potential renewable generation regions based on RESOP experience.

(ii) Please provide a map of the Hydro One distribution area showing those regions, if possible, and their relationship to the current distribution system. If Hydro One has identified areas of its distribution area that require reinforcement because of high renewable generation potential, please identify those areas of reinforcement, including in particular transformer stations and distribution facilities that have a high volume of CIAs.

Response

a) See the response at Exhibit H, Tab 1, Schedule 90, part (a).

b) i) See the response at Exhibit H, Tab 1, Schedule 146.
ii) See response to b) i) above.

School Energy Coalition (SEC) INTERROGATORY #17 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 10

Please provide a brief description of the main ways in which planning for generation connection customers differs from planning for load connection customers.

Response

The main differences between planning for load and generation connection customers on the distribution system in the current environment are flow direction considerations, predictability and behaviour of the connections, technology considerations and the pace and magnitude of the generation connection level.

The existing distribution system has evolved over many years. The form and function of the distribution system has been primarily to connect load customers with the expectation that flow is unidirectional from the transformer or distribution stations to the connected end points. Sufficient levels of generation as a result of a few large generators or an aggregate of many small generators can result in power flows on distribution facilities which are in the reverse direction than these facilities were designed for and have experienced. As a result the existing facilities may not have the capability, such as voltage control and system protection, to addressed the expanded range of potential conditions introduced.

Load connections are typically predictable with load profiles which are validated by many years of historical data. Load growth is also incremental and typically occurs gradually throughout the system. Many of the renewable resources are of an intermittent nature and can have significant fluctuations. There is much less historical data and actual operating experience on the Hydro One distribution system for generation as compared to load connections. The experience from the RESOP program and the high interest level expected for the FIT program suggests many more generation connections both in individual size and collective magnitude will be occurring over a much shorter period of time (i.e. less than 5 years) than has ever been experienced for load connections.

Another key difference for generation connections is the wide variety of generation devices that could be seeking connection to the distribution system. Issues of monitoring, control and proper coordination between not only the generators but also with the load customers will be essential to ensure that existing load customers are not adversely impacted. The availability, quality and experience of the models and modeling data for

the various generator devices will impact planning studies and connection assessments. This can represent a significant issue given that there are many emerging technologies both in generation and their associated electrical control facilities and auxiliaries.

School Energy Coalition (SEC) INTERROGATORY #18 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 13

Please provide the planning documents or analyses that form the basis for the figures of 3,500 MW by 2011 and a further 3,500 MW by 2014.

Response

The basis for the estimated 3,500 MW figures is discussed in the Green Energy Plan and in the response at Exhibit H, Tab 1, Schedule 146. Hydro One does not have further specific planning documents or analyses.

School Energy Coalition (SEC) INTERROGATORY #19 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 14

Please describe how the development work will be organized, e.g. will there be a separate generation connections planning/development unit, or will the costs described be split between existing departments. Please provide whatever breakdowns are available.

Response

The Development work related to generation connections requires different types of knowledge. Depending on the area of accountability and expertise required, a variety of existing departments in Hydro One are involved in this work. The costs described are split between these existing departments.

Currently Hydro One plans to continue leveraging the expertise of existing departments and does not plan to create a new separate department for the purpose of handling this development work.

School Energy Coalition (SEC) INTERROGATORY #20 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 17

Please advise whether the Applicant is proposing that its criteria or assessing benefits be applied to this Application regardless of the outcome of EB-2009-0349, or whether the Applicant's proposal is a placeholder, to be replaced by the Board's policy as developed through that consultation.

Response

Hydro One has included a set of criteria in its Green Energy Plan that it believes provide a reasonable basis for allocating the cost of investments between its own customers and all electricity rate payers in the province. Hydro One will follow the Board's direction in its Decision on this Application with respect to the allocation of costs pending the outcome of proceeding EB-2009-0349.

School Energy Coalition (SEC) INTERROGATORY #21 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 18

Please provide the full calculations summarized in lines 21-25.

Response

See the response at Exhibit H, Tab 7, Schedule 21.

School Energy Coalition (SEC) INTERROGATORY #22 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 23

Please provide the full calculations summarized in lines 2-3.

Response

See response at Exhibit H, Tab 7, Schedule 23.

School Energy Coalition (SEC) INTERROGATORY #23 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 24

Please provide the full calculations of the revenue requirement impacts for 2010 and 2011. Please show an alternative calculation which is the same in all respects, except that assets are amortized over the useful life normally applied to that category of assets, rather than using the 20 year amortization period described on lines 18-21.

Response

Below is the calculation of the revenue requirement impacts with respect to the Green Energy Act in 2010 and 2011.

	2010	2011
OM&A	0.0	0.0
Depreciation	3.5	12.8
Capital tax	0.1	0.0
Return on debt	2.2	8.2
Return on equity	2.2	9.0
Income tax	0.1	0.7
Total Revenue Requirement	**8.0**	**30.7**

Below is the calculation of the revenue requirement impacts with respect to the Green Energy Act in 2010 and 2011 assuming everything is held constant except that assets are amortized over the useful life normally applied to that category of assets, rather than using the 20 year amortization period.

	2010	2011
OM&A	0.0	0.0
Depreciation	3.1	11.1
Capital tax	0.1	0.0
Return on debt	2.2	8.2
Return on equity	2.2	9.0
Income tax	(0.1)	(0.0)
Total Revenue Requirement	**7.5**	**28.3**

School Energy Coalition (SEC) INTERROGATORY #24 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 26

Please describe the targeted studies on green energy technologies, including automated home energy networks and energy storage, in more detail, including any terms of reference or draft terms of reference currently in the Applicant's possession. If there are planning documents or other analyses relating to this part of the plan, please provide.

Response

Automated home energy networks refer to a situation where the customer has set up a network in their home to help manage energy consumption. Typically, there is a logic controller (usually a computer) that communicates to appliances and devices and causes them to adjust usage in accordance with pre-programmed criteria. This could be smart grid related if the logic controller can accept signals from the meter and help manage in-home devices to meet system needs (e.g. reduce energy consumption at peak times). Energy storage refers to all types of energy storage (battery, compressed air, fuel cell), both large and small scale, that could be accessed and utilized by Hydro One under certain conditions. One example is to maintain power quality due to fluctuating distributed generation supply or other system conditions. In both these cases, Smart Grid technology is needed to assess conditions and communicate to devices in order to meet customer needs.

For more information about Hydro One's activities regarding energy storage, please refer to the response at Exhibit H, Tab 1, Schedule 93 part e). To date, there have been no initiatives started regarding automated home energy networks.

There are no terms of reference specific to green energy technologies, however additional information related to both automated home energy networks and energy storage is expected through the Smart Grid RFP process, which is described in Exhibit H, Tab 12, Schedule 46.

School Energy Coalition (SEC) INTERROGATORY #25 List 1

Interrogatory

Cost of Capital

Reference: Exhibit A/Tab 14/Schedule 2, page 27

Please calculate the funding adder that would be appropriate, in the view of the Applicant, if the Board's planning guideline were to be followed.

Response

Hydro One does not plan to recover smart grid related costs through variance account and funding adder as it believes that its Smart Grid investments are necessary, used and useful, and appropriately included as part of its rate base expenditures for the test years.

School Energy Coalition (SEC) INTERROGATORY #26 List 1

Interrogatory

OM&A

Reference: Exhibit C1/Tab 2/Schedule 1, OM&A Overview

Preamble:
HON is requesting a 22% increase in OM&A from 2008 to 2011. In the evidence HON identifies a few select areas of OM&A expenditures that are the main drivers of the overall increase in OM&A, namely: increased expenditures in the areas of vegetation management, line maintenance, and expenditures related to PCB regulations and development OM&A associated with Green Energy and Green Economy Act.

(a) Assuming the areas identified represent increases in expenditure that are unavoidable, what other areas of discretionary OM&A spending has HON considered reducing in order to keep the overall increase in OM&A to a reasonable level?

(b) Please complete the following table:

		2009	2010	2011
	Total Opening OM&A (previous year's total) ($ millions)	$471.3	$527.2	$560.0
	Increase related to:			
(1)	Vegetation Management			
(2)	Station Maintenance Related to PCB Regulations			
(3)	Development OM&A expenditures related to GEGEA			
(4)	Increased Shared Services cost related to increased SDO expenditures identified in (1) (2) and (3) above only.			
(5)	Total of (1) to (4) above			
(6)	Total other increases in OM&A [(7) –(5)]			
(7)	Closing OM&A	$527.2	$560	$575.2

(c) Assuming HON were forced to restrict its overall OM&A spending so that it increased by, say, 5% per year (i.e. up to $519.6 million in 2010 and $545.6 million by 2011, using 2008 as the starting point), what discretionary OM&A expenditures could be reduced or deferred to achieve the $72.9 million and $60.6 million savings in 2010 and 2011 respectively?

Response

a) As discussed in Exhibit A, Tab 14, Schedules 6, beginning on page 4, Hydro One Distribution considers multiple investment levels for all subsets of its expenditures. Lower expenditure levels will give rise to greater risks. To settle on appropriate expenditure levels, Hydro One Distribution utilizes the planning and prioritization process that strikes an appropriate balance among risks to business values, customer rate impacts, and other factors. The expenditure levels proposed as part of the current application were determined using the prioritization process and are considered prudent.

b) Please refer to the following table:

		2009	2010	2011
(0)	Total Opening OM&A (previous year's total) ($ millions)	$471.3	$527.2	$560.0
	Increase related to:			
(1)	Vegetation Management	$17.9	($2.9)	$11.4
(2)	Station Maintenance Related to PCB Regulations	-	$3.8	$1.8
(3)	Development OM&A expenditures related to GEGEA	$7.6	$11.1	-
(4)*	Increased Shared Services cost related to increased SDO expenditures identified in (1) (2) and (3) above only.	NA	NA	NA
(5)	Total of (1) to (3) above	$25.5	$12.0	$13.2
(6)	Total other increases in OM&A [(7) –(5) – (0)]	$30.4	$20.8	$2.0
(7)	Closing OM&A	$527.2	$560	$575.2

* Increases in Shared Services cost cannot be allocated on the basis requested.

c) Please see the response to Exhibit H, Tab 1, Schedule 14

School Energy Coalition (SEC) INTERROGATORY #27 List 1

Interrogatory

Sustaining OM&A

Reference: Exhibit C1/Tab 2/Schedule 2, OM&A: Station:

(a) Pg. 5-6, *demand and corrective maintenance*: the evidence states that spending in this area in recent years has been reduced due to fewer failures, which are a result of increases in preventative maintenance. Spending in 2011, however, is still 26% higher than 2009. Please explain what assumptions have been made to arrive at the 2010 and 2011 expenditures in this area.

(b) Pg. 8: Planned Station Maintenance, PCB testing and refurbishment: the evidence states that PCB-related spending is projected to be $3.8 and $5.6 million in 2010 and 2011 respectively. Please provide a breakdown of the planned spending and state what assumptions have been made to arrive at the projections.

Response

a) Please refer to Exhibit H, Tab 1, Schedule 16.

b) Please refer to Exhibit H, Tab 12, Schedule 8.

School Energy Coalition (SEC) INTERROGATORY #28 List 1

Interrogatory

Sustaining OM&A

Reference: Exhibit C1/Tab 2/Schedule 2, OM&A: Station:

Preamble:
With respect to Trouble Calls (pg. 11): in HON's last Distribution rate application, HON sought and was granted an increase in vegetation management expenditures, primarily on the basis that greater spending in this area would result in lower incidents of tree contact and hence fewer trouble calls.

(a) Please state the level of accomplishment in vegetation management (line clearing and brush control) from 2007 to 2010;

(b) State whether the increased accomplishment was factored into HON's budget assumptions for trouble calls for 2010 and 2011 and if so how.

(c) The evidence states that the 2010 and 2011 spending requirements are based on an forecast volume of 49,900 Trouble Calls. Please provide the number of trouble calls received in each of 2006, 2007, 2008 and (estimated) 2009.

(d) The evidence states that 2006 and 2008 expenditures were higher than normal due to an unusually high number of damaging storms. If possible, please provide a "normalized" expenditure for those years assuming there had been a normal level of storm damage.

Response

a) Please refer to Exhibit H, Tab 1, Schedule 34.

b) Please refer to Exhibit H, Tab 1, Schedule 18.

c) Please refer to Exhibit H, Tab 1, Schedule 19.

d) Please refer to Exhibit H, Tab 1, Schedule 20. The “Escalated Expenditures Used for Forecast” shows the “normalized” expenditures for the two abnormally active storm years (i.e. 2006 and 2008).

School Energy Coalition (SEC) INTERROGATORY #29 List 1

Interrogatory

Sustaining OM&A

Reference: Exhibit C1/Tab 2/Schedule 2, page 29, OM&A: Metering:

(a) Customer Retail Meters: the evidence states that spending in this area has been reduced in recent years due to the dispensation from Measurement Canada in view of the fact that meters will be replaced by smart meters. What then accounts for the $1.3 million (27%) increase in spending in 2011 over 2010?

Response

As described on page 29 of Exhibit C1, Tab 2, Schedule 2, the Measurement Canada dispensation applies up to 2010. The savings associated with the dispensation no longer apply beyond 2010 and Smart Meter sampling and re-verification will start in 2011. The increase in costs in 2011 also provides for Smart Meter trouble call and corrective maintenance along with maintenance of new Smart Meter telecom components (e.g. repeaters and collectors).

School Energy Coalition (SEC) INTERROGATORY #30 List 1

Interrogatory

Sustaining OM&A

Reference: Exhibit C1/Tab 2/Schedule 2, OM&A: Vegetation Management

(a) Pg. 31: please confirm that the numbers in the following table are correct, and fill in the numbers that are missing (i.e. accomplishment for 2007, 2008, and 2009):

									% Change: 2004-2011
	2004	2005	2006	2007	2008	2009	2010	2011	
Vegetation Mgmt (Total)	88.9	86.4	89.1	115.0	118.2	136.1	133.2	144.6	
Line Clearing	55.6	52.9	50.6	74.1	78	88.3	84	91.6	
Accomplishment	10,361	8,746	8,889				13,500	14,300	
Cost/KM	5,366.3	6,048.5	5,692.4				6,222.2	6,405.6	19.3%
Brush Control	19.6	21.1	25.2	26.9	25.8	31.3	33.3	36.2	
Accomplishment	10,731	9,076	10,246				13,500	14,300	
Brush Control cost/ KM	1,826.5	2,324.8	2,459.5				2,466.7	2,531.6	38.6%

(b) explain the year over year changes in cost per kilometre.

(c) Pg. 35, line 25: the evidence states that HON hired external contractors to perform vegetation management work that could not be resourced by internal staff. Does HON have cost data analyzing the cost/KM (or other metric) as between external contractors hired to do vegetation management work versus the cost of using HON staff? If so, please provide it.

Response

a) Please see the table below.

									% Change: 2004-2011
	2004	2005	2006	2007	2008	2009	2010	2011	
Vegetation Mgmt (Total)	88.9	86.4	89.1	115.0	118.2	136.1	133.2	144.6	62.7%
Line Clearing	55.6	52.9	50.6	74.1	78.7	88.3	84	91.6	64.7%
Accomplishment	10,361	8,746	8,889	12,211	12,163	12,800	13,500	14,300	38.0%
Cost/KM	5,366	6,049	5,692	6,068	6,470	6,898	6,222	6,406	19.3%
Brush Control	19.6	21.1	25.2	26.9	25.8	31.3	33.3	36.2	84.7%
Accomplishment	10,731	9,076	10,246	10,777	10,856	12,500	13,500	14,300	33.3%
Brush Control cost/ KM	1,827	2,324.8	2,459	2,496	2,376	2,504	2,467	2,532	38.6%

b) Line Clearing – Costs vary from one year to the next depending on various factors including the proportion of kilometers in heavily treed areas, the number of off-road vs. on-road kilometers, and other site specific characteristics (e.g. tree species, urban locations). Since 2004, unit costs have varied based on the aforementioned factors and their impact on the mixture of kilometers cleared in any given year.

Brush Control – Brush control costs are primarily dependent on brush densities, height and type of treatment, e.g., mechanical or herbicide, as such one can expect some variability in costs year over year as can be seen in the table above.

c) Please refer to Exhibit H, Tab 1, Schedule 33.

School Energy Coalition (SEC) INTERROGATORY #31 List 1

Interrogatory

Development OM&A

Reference: Exhibit C1/Tab 2/Schedule 3, Development OM&A (Pg. 3)

with respect to Data Collection, Engineering and Technical Studies (increase from $4.1 million in 2008 to $6.7 million in 2009 and remaining at that level during the test years):

(a) please set out what new projects the extra $2.8 million in annual expenditure will be used for.

(b) If the projects for 2010 and/or 2011 have not been identified, please state how the forecasted expenditures for those years were determined.

Response

a) The additional $2.8M is not associated with any specific projects but rather for the anticipated cost to manage relationships with distributed generators and resolve operating issues. The level of activity in this area is expected to increase significantly in 2009 and during the test years, consistent with the forecasted increase in the number of generation connections as shown in Table 3 of Exhibit D1, Tab 3, Schedule 3.

b) See part a)

School Energy Coalition (SEC) INTERROGATORY #32 List 1

Interrogatory

Development OM&A

Reference: Exhibit C1/Tab 2/Schedule 3, Development OM&A, Smart Grid Standards and Technology

(a) Please provide a breakdown showing how specifically the forecast expenditures in this area ($10 million in each of 2010 and 2011) was determined. What specific projects or initiatives are contemplated and how was the amount determined? Please provide all assumptions used in determining the spending forecast.

Response

For details regarding the Smart Grid budgets, please refer to Exhibit H, Tab 9, Schedule 13. For details regarding the RFP process which will be used to update budgets as necessary, please refer to Exhibit H, Tab 12, Schedule 46.

School Energy Coalition (SEC) INTERROGATORY #33 List 1

Interrogatory

Operations OM&A

Reference: Exhibit C1/Tab 2/Schedule 4, Operations OM&A,

(a) Operations: the 2010 forecast ($12.4 million) expenditure is 43% higher than 2008 (the 2011 forecast- $12.8 million- is 47% higher than 2008.) The evidence (at p. 8) states that the 2010 and 2011 forecast spending is "higher than the amounts in historic years as a result [of] increased focus on Distribution elements in alignment with distributed generation, smart meter, and smart grid influences." Please provide a more detailed breakdown of how the 2010 and 2011 forecasts were determined. Please provide all assumptions used in determining the spending forecast.

(b) Operations Support: the evidence states (at p. 9) that the test year forecast for this program ($4.3 and $4.8 million respectively, up about 23% over 2008) "are greater than historic expenditures as a result of additional updates and support for tools associated with generation connections." Please provide a more detailed breakdown of how the 2010 and 2011 forecasts were determined. Please provide all assumptions used in determining the spending forecast.

Response

a) The 2010 and 2011 forecasts were determined based on the assumption that OGCC will be staffed at compliment necessary to deliver the range of services described in detail on pages 6 to 8 of Exhibit C1, Tab 2, Schedule 4, including the additional work associated with Distributed Generation, Smart Meter and Smart Grid influences.

b) Operating Support OM&A costs are only marginally higher than the actual cost of $4.1M in 2006 and 2007. The Outage Response Management System and the Network Management System will be expanded to capture generation connections. The Distribution Operating Diagrams and Station Operating Diagrams will be updated with the new generator connections and related system upgrades to provide the accurate and detailed information on the configuration of the distribution system necessary to ensure the safe and reliable system operation.

School Energy Coalition (SEC) INTERROGATORY #34 List 1

Interrogatory

Customer Care

Reference: Exhibit C1/Tab 2/Schedule 5, Customer Care

Preamble

Excluding meter reading costs, which are declining due to significant expenditures on smart meters, Customer Care costs increase 22% from 2008 to 2011. The main driver is increases in Base Services Cost other than meter reading, in particular, Other Field Support Costs (53% increase), Other Service Support Costs (26% increase), and (**100%** increase).

Questions:

(a) Other Field Support Costs (p.9): the evidence states only that these costs (total increase of $3.7 million from 2008 to 2011) are increasing "due to an increase in field collections and investigation work related to receivables management." Please provide a more detailed breakdown of how the 2010 and 2011 forecasts were determined. Please provide all assumptions used in determining the spending forecast.

(b) Other Service Support costs: please provide a more detailed breakdown of the increase in costs in this area from 2008 ($8.5 million) to 2009 ($10 million);

(c) Customer Care Management: this program increases from $6.4 million in 2008 to $11.4 million in 2010 and $12.8 million in 2011. The evidence (at p. 11) states only that the increase is "due to expanded accountabilities of Customer Care to address the unique service needs required for new renewable distributed generator customers." Please provide a more detailed account of specific work will be performed and the associated cost. Please provide all assumptions used to in determining the spending forecast.

Response

a) Other Field Support costs reflect field work required to support the billing and collections programs. Additional activities are included in the test years associated with increased field clerical support to dispatch and schedule activities and work to manage order tracking and closing. Costs are also increasing due to annual labour escalation.

b) 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 $1.5M increase breaks down as follows:

Collections related costs contribute $0.2M. Customer Care is making increased investments in collection activities. These activities include increased outbound call reminders to past due customers and an increase in expected collection agency fees.

Billing related costs contribute approximately $1.1M to the increase due to three factors; higher postage rates and increased volume of bills; an increase in the costs associated with cheque processing; the introduction of ePost services; and retailer hub services.

Call handling costs contribute $0.2M and reflect higher telephone and other miscellaneous costs.

c) The additional Customer Care Management activities anticipated in 2010 and 2011 related to servicing renewable generation customers are as follows:

- Establish dedicated contacts for generator customers
- Manage settlement of metering data and financial settlement with IESO

These activities account $3.3 million in 2010 and $4.4 million in 2011.

Please see response at Exhibit H, Tab 1, Schedule 54 for a description of additions to the Total Customer Care Work Program to serve renewable distributed generation customers, including the assumptions used to determine the services added and resulting spending forecast.

School Energy Coalition (SEC) INTERROGATORY #35 List 1

Interrogatory

Shared Services

Reference: Exhibit C1/Tab 2/Schedule 7, CCFS and Other OM&A

(a) please insert a column to Table 1 on page 2 showing the 2008 Dx Allocation for the various CCFS costs.

(b) **Finance**: please provide the budget for Finance on a normalized basis from 2006 to 2011, showing all costs transferred out of Finance in 2008.

(c) **Human Resources**: Please provide a more detailed breakdown of the projected $5 million (37%) increase in Human Resources costs between 2008 and 2011. Please state all assumptions used to derive the 2010 and 2011 forecasts.

(d) **Corporate Communications and Services**- pg. 12:

(i) what portion of the increase between 2008 and 2009 is due to a re-allocation of costs formally recorded in Finance?

(ii) Please provide the budget for First Nations and Metis Relations for each of 2008 and 2009.

(iii) Please state how the extra expenditures in First Nations and Metis Relations will be spent in 2010 and 2011. Please include all assumptions made in arriving at the test year forecasts.

Response

a. Please refer to response at Exhibit H, Tab 1, Schedule 63.

b. To address this requirement, total Finance costs for 2006-2008 were normalized to exclude Outsourcing Services and Enablement, which were transferred from Finance in 2009. For years prior to 2008, costs associated with Outsourcing Services were reported in Asset Management. The Enablement function was a new group formed in 2008 (all amounts in $ millions):

Function	**2006**	**2007**	**2008**	**2009**
Finance Costs as reported in pre-filed evidence	22.3	22.4	32.2	32.7
Exclude Outsourcing Services	-	-	(2.2)	-
Exclude Enablement	-	-	(2.3)	-
Finance Costs, normalized	22.3	22.4	27.7	32.7

c) Human Resources costs comprise labour and non-labour expenses. Labour costs include all salaries and benefits payable to Hydro One staff. Non-labour expenses primarily comprise costs for consultants, contractors, employee expenses and Inergi outsourcing. Budgets are developed using approved assumptions for labour escalation and benefit cost rates. The increase in costs from 2008 to 2011 result from employee and leadership development programs and expansion of recruiting activities to address anticipated growth in Hydro One work programs as outlined in Exhibit C1, Tab 2, Schedule 7. This will be handled by adding staff in Human Resources and engaging external consultants to support such programs as leadership development, diversity and resourcing, recruitment screening and employee surveys.

d)

i) In 2009, total Outsourcing Services costs of $2.6 million were reported in Corporate Communications and Services. Before this transfer the increase in Corporate Communication costs from 2008 to 2009 is $0.9 million:

Function	2009 Bridge	2008 Historic	Increase
Corporate Communications & Services per evidence	9.6	6.1	3.5
Outsourcing Services	(2.6)	-	(2.6)
Total before Outsourcing Services	7.0	6.1	0.9

All amounts in table above in $ millions.

ii) In the table below are the budgets for First Nations and Métis Relations for 2008 and 2009:

In $ Millions	2008 Budget	2009 Bridge
First Nations & Métis Relations	0.4	1.5

iii) In carrying out its consultation with First Nations and Métis, Hydro One aims to develop relationships of mutual respect and trust. Hydro One's First Nations and Métis consultation strategy applies to the First Nations and Métis groups who are potentially affected by the GEGEA. Hydro One's preliminary research into the 20 Green Plan projects reveals that approximately 160 First Nations and Métis communities will need to be consulted. Six priority projects have been identified and 65 communities will be involved in consultations and negotiations of benefit agreements. While having done some preliminary investigations into which First Nations or Métis communities might be involved in consultations, it remains very difficult to predict how simple or complicated any negotiation or consultation with a specific community will go. Given the diversity of communities that exists in Ontario, each consultation or negotiation table will be unique.

School Energy Coalition (SEC) INTERROGATORY #36 List 1

Interrogatory

Shared Services

Reference: Exhibit C1/Tab 2/Schedule 8, Shared Services: Asset Management

(a) Pg. 3: please insert a column to Table 1 (Asset Management Function ($ millions)) showing 2008 allocation to Distribution.

(b) Please provide a chart summarising what aspects of the total increase in Asset Management from $100.3 million in 2008 to $145.7 million by 2011, is related to investments required or prompted by the Green Energy Act. Please include a summary of the work and the budget.

(c) Strategy and Business Development: the budget for this function almost doubles from 2008 to 2011 (from $6.3 million to $12.5 million). The evidence, however, merely provides a bullet-point list of what the two functions (Strategy and Conservation, and Business Development) do, without providing any evidence as to how the increased budget will be spent or how the budget was arrived at. Therefore, please provide details of how the increased budget will be spent as well as any assumptions made in determining the 2010 and 2011 forecasts.

(d) The System Investment function increases by $14.5 million (61%) between 2008 and 2011. Please provide a more detailed account of what additional work and/or accomplishment the increased spending will go towards including all assumptions used in determining the 2010 and 2011 budgets.

Response

a) Please refer to the interrogatory response in Exhibit H, Tab 1, Schedule 43.

b) The additional resources for Asset Management function to support the initiatives of the Green Energy Act are reflected in the costs for test years 2010 and 2011. For the costs being driven by the Green Energy Initiatives please refer to part b) of the response to Exhibit H, Tab 7, Schedule 62.

For information relating the activities of the Asset Management function, please refer to Exhibit C1, Tab 2, Schedule 8

c) Please refer to the interrogatory response to part b) in Exhibit H, Tab 7, Schedule 61.

d) Groups within Asset Management including System Investment, provide support to both the transmission and distribution businesses, based on the demands and requirements of the overall capital and OMA work programs. The 61% costs increases are driven by the additional efforts to replace the end-of-life assets across the transmission and distribution systems, as well as the Green Energy initiatives. These costs reflect the increased demands required to fulfill the needs of the growing transmission and distribution capital and OMA work programs

The increased activities for System Investments for 2009 to 2011 are detailed in Exhibit C1, Tab 2, Schedule 8, pages 8 to 9.

School Energy Coalition (SEC) INTERROGATORY #37 List 1

Interrogatory

Shared Services

Reference: Exhibit C1/Tab 2/Schedule 9, Shared Services: Information Technology

(a) Pg. 3: the evidence states that the 2009 and 2010 IT management costs increase due to the transfer of two departments into IT from Finance. Please provide the budget for those functions from 2008 to 2011.

Response

Department #1: the Enablement department was originally created in Finance in 2008 to drive productivity and ensure SAP and related assets were leveraged to their full potential. Staffing of this group began mid-way through 2008 and consisted of both net new SAP knowledgeable resources and Hydro One experienced staff that rolled off the Cornerstone Phase 1 project, reaching the full complement in early 2009.

- The 2008 spend was $2.3M.
- The 2009 forecast for this department is $6.6M.
- The budget in 2010 is $7.3M
- The budget in 2011 is $7.9M.

Department #2: The Information Assets department resides within the Asset Management division.

- The 2008 spend was $4.6M.
- The 2009 forecast for this department is $4.7M.
- The budget in 2010 is $5.2M
- The budget in 2011 is $5.4M.

School Energy Coalition (SEC) INTERROGATORY #38 List 1

Interrogatory

Shared Services

Reference: Exhibit C1/Tab 2/Schedule 11, Cost of Sales- External Work

(a) Please explain whether any of distributed generation work (total budget $36.2 and $36.3 million in 2010 and 2011 respectively) work is being charged to the Global Adjustment Fund.

(b) Please explain what revenue HON would realize from distributed generation.

Response

a) The Cost of Sales (Lines – Contestable Work) amounts of $36.2 and $36.3 million for 2010 and 2011 respectively that were initially included in Exhibit C1, Tab 2, Schedule 11 Table 1, filed with the Ontario Energy Board on July 13, 2009 were subsequently revised in the updated exhibit filed on September 25, 2009.

The revised amounts are $5.2 and $5.3 million for 2010 and 2011 respectively, and do not include any work to connect distributed generators. The revised amounts of $5.2 and $5.3 are not charged to the global adjustment fund.

b) In our current forecast, we have revenue associated with Distribution Generation Studies of $3.2M in 2010 and in 2011 (per Exhibit E1, Tab 1, Schedule 2, Table 2

School Energy Coalition (SEC) INTERROGATORY #39 List 1

Interrogatory

Shared Services

Reference: Exhibit C1/Tab 3/Schedule 2: Compensation, Wages and Benefits

(a) The evidence discusses the study by the C.D. Howe Study that found that declaring a service an "essential service" results in higher wages than would otherwise have occurred in traditional collective bargaining. In HON's evidence, however, HON states that it would be unable to continue operations for a sustained period of time during a PWU strike. Given the nature of HON's service and its importance to the province of Ontario, that statement essentially means that HON conducts bargaining on the assumption that it could not allow a strike to take to occur.

Response

This statement is mixing up the former process used in Society bargaining with the process used in PWU bargaining. The reference to the CD Howe study was made in the context of Society bargaining because it provides third party support for Hydro One's decision not to extend interest arbitration to resolve collective bargaining disputes as being prudent.

The option for interest arbitration for PWU bargaining is not available to Hydro One. As such, Hydro One enters into every round of bargaining assuming that either party can elect to exercise its legal right for a strike or lock out to resolve outstanding bargaining items. Hydro One does recognize a strike would likely result if Hydro One attempted to significantly alter wages, benefits and pensions. Rather than risk the supply of reliable electricity, the focus at bargaining with the PWU has been to negotiate increased flexibility and specific cost reduction items rather than wide scale wage, benefit and pension reductions. Table 1 at Exhibit C1, Tab 3, Schedule 2, pp 5-6 demonstrates flexibility and cost reductions that have been achieved. Equally important is the fact that costs in the area of wages, benefits and pensions have been reasonably contained.

School Energy Coalition (SEC) INTERROGATORY #40 List 1

Interrogatory

Shared Services

Reference: Exhibit C1/Tab 3/Schedule 2: Compensation, Wages and Benefits

(a) In the current evidence at C1-3-2, p. 13, HON states that it believes the best comparators to HON's compensation system are the Ontario Hydro successor companies. In that case:

(i) Was Mercer/Oliver Wyman, which prepared the HON compensation benchmarking report that was submitted as part of HON's 2009/2010 transmission application (EB-2008-0272), told to restrict its analysis to Ontario Hydro successor companies? Why not?

(ii) When did HON first form the opinion that the successor companies, as opposed to the comparators used in the Mercer/Oliver Wymann report, are the best comparators to HON?

(b) Both OPG and Bruce Power, the two companies HON suggests are the most appropriate comparators to HON, are generating companies whose business comprises a significant component of nuclear generation (100% in the case of Bruce Power and approximately 30% in the case of OPG). Given the differences between the two types of business:

(i) How relevant are OPG and Bruce Power as comparators for HON?

(ii) Is it possible that the wages across the different lines of business may have been artificially flat while all three companies were under the same corporate umbrella (i.e. a Mechanical Maintainer was paid close to the same wage whether he or she worked for the Distribution, Transmission or Generation division of Ontario Hydro) but thereafter the additional complexities involved in electrical generation, particularly nuclear generation, may have played a part in the disparate wage-growth shown at pg. 14?

(iii) In its Decision With Reasons in EB-2008-0272, the Hydro One Transmission rate application for the 2009 and 2010 test years, the Board examined HON's compensation levels as compared to comparable utilities and found it to be excessive. The Board concluded [at p. 30] that it is "appropriate to disallow some compensation costs because these costs are substantially above those of other comparable companies and the company has failed to demonstrate that productivity levels offset this situation."

Leaving aside HON's argument in the pre-filed evidence in the current application regarding the comparison to Bruce Power and OPG, can HON point to any material change between the Transmission decision and now that would justify a different decision in this proceeding?

(iv) The Board in the Transmission decision disallowed $4 million in each of the test years to account for what it deemed to be HON's excessive compensation costs. Assuming a similar result in this proceeding, what does HON say is a comparable number for Distribution (given both the size of the Distribution business relative to the Transmission business as well as the increase in spending in 2010 Dx vs. 2009 Tx)?

Response

a)

i) No, Mercer/Oliver Wyman were not told to restrict the analysis to the Ontario Hydro successor companies. In the OEB's Decision with Reasons (EB 2006-0501), Hydro One was asked to provide '*useful and reliable information concerning Hydro One's compensation costs, and how they compare to those of other regulated transmission and /or distribution utilities in North America'*. Restricting the peer group to the successor companies of Ontario Hydro would not comply with the Board's directive.

ii) Hydro One has always felt that a better comparator for our PWU positions would be the successor companies to Ontario Hydro.

b)

i) Ontario Power Generation and Bruce Power would be very relevant comparators for Hydro One Networks. Hydro One competes for staff with and is vulnerable to losing staff to these organizations. Hiring apprentices, new grads and professional staff are areas in which we compete with both OPG and Bruce Power. Hydro One has lost trained and experienced staff to most of the successor companies. As such, Hydro One's total compensation is very relevant to the total compensation paid at OPG and Bruce Power.

ii) This is highly unlikely. It makes little sense that the PWU would acquiesce in its responsibility to represent its members by allowing a group of employees to have an artificially low compensation. Hydro One also operates in a very complex and often dangerous work environment. Mechanics or electricians at either OPG, Bruce Power or Hydro One all work in a similarly complex work environment. The fact that OPG and Bruce Power produce nuclear power does not mean the trades support is that more complicated and justifies a difference in wages.

iii) Hydro One believes that a disallowance similar to Transmission is not appropriate and that the prefiled evidence supports our compensation levels. It must be noted that over 90% of Hydro One's workforce is unionized and wages and benefits are covered by the respective collective agreements which expire beyond 2010. Collective agreements are legally enforceable contracts and cannot be unilaterally changed. Any reduction in our revenue requirement resulting from a comparison to market median will not reduce wages and benefits but would require a reduction in work programs.

iv) Notwithstanding our concerns regarding such a reduction, and assuming a similar methodology as in Transmission and 2010/2011 proposed budget levels, a potential disallowance would be approximately $9 million in each year.

School Energy Coalition (SEC) INTERROGATORY #41 List 1

Interrogatory

Capital Expenditures

Reference: Exhibit D1/Tab 3/Schedule 2: Sustaining Capital: Lines: Trouble Calls and Storm Damage

(a) The evidence states, at p. 16, that proposed spending for the test years is based on a 4-year average of historical spending with adjustments made to incorporate recent trending in volumes and cost. Please provide further detail on what adjustment were made.

(b) Please explain how increased investment in vegetation management and sub-marine cable replacement have been factored into the trouble call and storm damage spending forecast.

Response

a) Adjustments were made to the forecast of Storm Damage. The detailed calculation illustrating the adjustments is provided in Exhibit H, Tab 1, Schedule 20.

b) Please refer to Exhibit H, Tab 1, Schedule 18 for response with respect to vegetation management.

As discussed at the bottom of page 16 of Exhibit D1, Tab 3, Schedule 2, Hydro One anticipates an increasing need for submarine cable trouble call expenditures over the 2010 and 2011 period. This is based on the new submarine cable testing program that was launched in 2008 that is identifying a greater number of cable installations that require emergency attention. Over the longer term, the increased emphasis on cable testing and refurbishment is expected to reduce the volume of emergency work required on cable plant.

School Energy Coalition (SEC) INTERROGATORY #42 List 1

Interrogatory

Capital Expenditures

Reference: Exhibit D1/Tab 3/Schedule 8: Shared Services: Facilities & Real Estate and Security Infrastructure

(a) The evidence states that the substantial driver for the large increases in spending in Facilities and Real Estate (from $22.1 million in 2008 to $50.3 million by 2011) is "the need to provide suitable space and to accommodate the staff resources and equipment required to handle the substantial growth in core sustaining, development and operations work programs over this period." However, the evidence does not describe what spending is due to expansion of the work program and what is due to refurbishing and/or replacing worn out facilities. Therefore, please identify the total spending in this area that is due to expansion of the work program (primarily accommodation for new staff).

(b) With respect to the planned capital improvements to 483 Bay St.:

(i) Please provide a more detailed summary of the planned $39.8 million in planned capital improvements. The investment summary document (C2) describing the project is mainly a copy of the description given in the evidence.

(ii) How much of the $39.8 million in improvements is due to expansion to accommodate new staff?

(iii) Please provide a copy of any business case, cost-benefit analysis or net present value analysis conducted in support of the planned expenditure at 483 Bay St.

(iv) Does HON have an option to renew the lease at 482 Bay St. beyond the 11-year term that was recently agreed to?

(v) Is any portion of the planned improvements to 483 Bay St. payable by the landlord? If not, why not?

Response

a) The expenditures as provided in the exhibit can be further broken down by investments in head office and field facilities. Please refer to the table below.

Description	Historic			Bridge	Test	
	2006	2007	2008	2009	2010	2011
Head Office Facilities	$0.2	$2.7	$1.3	$0.6	$32.0	$32.4
Field Facilities	$3.4	$6.9	$5.8	$21.4	$18.9	$17.9
Total	**$3.6**	**$9.6**	**$7.1**	**$22.1**	**$50.9**	**$50.3**

Historically Head Office facilities investments are mainly driven to accommodate additional staff levels as result of work expansion. Hydro One Networks head office lease will be ending on January 31, 2010. The existing premises are approximately 25 years old and the interiors are in need of upgrade and/or replacement. Within the recently completed lease renewal of 483 Bay, the head office investment accommodates some of the recent staff growth but as well responds to the need of capital improvements to existing premises which are in excess of 25 years old and require improvements. (The head office does not address accommodation needs as result of recently announced work program initiatives, e.g. Distributed Generation and the Green Energy Act.)

The major investments decisions in the field facilities are not driven exclusively by growth or replacement of existing facilities alone but rather are made based on facilities assessment that considers a number of factors including facilities that are near the end of their life, inadequate for changing business needs (this includes providing accommodation for additional staff) or which historically were experiencing operating deficiencies including health and safety issues. In addition to these criteria the requirements of business units are examined in short and long term needs and acceptable accommodation alternatives available in the local real estate markets. Based on these considerations decisions are made to build new facilities, conduct major renovations including building additions to existing promises or consider limited lease options. In addition structural and other building improvements are conducted on priority bases to existing facilities as result of asset condition assessments. The level of the capital sustainment spending may vary from year to year depending on business circumstances.

b)

i) The head office leasehold improvements are estimated in total cost of $19.4M and $20.4M in years 2010 and 2011 respectively. As part of the lease terms renewal the total leasehold improvements costs are indirectly offset by tenant improvements allowance committed by the Landlord of $11.6M including additional base building improvements. This includes estimated $3.2M for base building improvements costs to be refunded to Hydro One by landlord as part of tenant inducements. The Landlord tenant improvements allowance will be amortized over the term of the lease and treated as a credit to operating expense, which has been reflected in operating budget.

ii) In 2005 Hydro One exercised lease renewal option and entered into five year lease agreement with current landlord at 483 Bay Street for a total rentable area of 190,000 sq. feet. In 2007 a decision was made to relocate Inergi LP staff from Hydro One head office location in order to accommodate at that point in time Hydro One head office workspace requirements. As result, Hydro One secured additional leased office space of approximately 40,000 sq. feet at Atrium on Bay location (20 Dundas West) to accommodate relocation of Inergi Staff. In the subsequent year Hydro One continued to experience work program expansion, and ultimately in 2008 additional 60,000 sq. feet of office space was subleased at 483 Bay Street as result of the staff growth.

A survey of the various business units in the early part of 2008 identified a consolidated requirement for approximately 280,000 square feet of office space for Hydro One Networks Head Office. This requirement included consolidation and at that time planned growth of approximately 1,700 staff. A new eleven year lease term at 483 Bay Street commencing Feb1, 2010 will be comprised of approximately 285,000 sq. feet and will replace the total current leased and recently subleased at 483 Bay Street of 190,000 sq. feet and 60,000 sq. feet respectively. This does not include Atrium on Bay space (40,000 sq. feet) which is not included in the 483 Bay Street head office space (285,000 sq. feet). The head office does not address accommodation needs as result of recently announced work program initiatives, e.g. Smart Metering, Distributed Generation and recent Government of Ontario announcement, where it had asked Hydro One to proceed with transmission projects to support the Green Energy Act. As result of this directive and new work initiatives that emerged after head office space requirements were finalized, more accurate, additional space assessment requirements will be conducted with respective Company Business Units to determine additional work space needs.

iii) The requested material is considered confidential and will be filed with the OEB separately.

iv) As part of the newly reached lease term at 483 Bay Street commencing February 1, 2010 Hydro One has the option to renew the lease beyond eleven year term.

v) Please see response to question Bi)

School Energy Coalition (SEC) INTERROGATORY #43 List 1

Interrogatory

Capital Expenditures

Reference: Exhibit D1/Tab 3/Schedule 8: Shared Services- Transport and Work and Service Equipment

(a) Please provide a detailed breakdown of the planned $133.4 million and $74.1 million (in 2010 and 2011 respectively) in expenditures for Transport and Work Equipment.

Response

Type of Equipment	2010 Capital Allocation	2011 Capital Allocation
Heavy Equipment	$ 1.8	$ 1.8
Light Transport	$ 17.7	$ 11.7
Off Road Equipment	$ 6.2	$ 6.5
Work Equipment	$ 105.4	$ 51.6
Miscellaneous (Trailers, Forklifts, Boats, etc)	$ 2.4	$ 2.5
Grand Total	**$ 133.4**	**$ 74.1**

School Energy Coalition (SEC) INTERROGATORY #44 List 1

Interrogatory

Capital Expenditures

Reference: Exhibit E1/Tab 1/Schedule 2: External Revenue

Preamble

In the original evidence filed July 13, 2009 external revenues for the test years were $82.2 million and $82 million respectively. In the updated evidence that number has dropped to $48.2 and $48.1 million respectively. The major change appears to be in the area of Lines-Other Contestable work, which has decreased from an original forecast of $39 million in each of the test years to $5 million.

(a) There appears to be an almost identical update made to Shared Services OM&A: Cost of Sales (C1-2-6). Please explain whether there is a relationship between the two and what accounts for the change in forecast.

(b) Please state whether the change in forecast affects any other area of the application, such as planned Development Capital or OM&A spending.

Response

a) Yes, there is a relationship between the two. The shared services OM&A cost of sales Exhibit C1, Tab 2, Schedule 6 shows the costs incurred to earn the external revenue in Exhibit E1, Tab 1, Schedule 2. The forecast of external revenue and associated cost of sales was revised to reflect the changes in cost responsibility per the proposed DSC amendments issued by the Board on September 11, 2009.

b) Yes, the change in forecast of External Revenues, and the re-categorization of associated Cost of Sales as Capital work under the Generation Connections program has resulted in changes to the Shared Services OM&A, Development Capital and Green Energy Plan evidence as detailed in the cover letter dated September 25, 2009 that was included with Hydro One's update to the pre-filed evidence.

School Energy Coalition (SEC) INTERROGATORY #45 List 1

Interrogatory

Capital Expenditures

Reference: Exhibit G1/Tab 3/Schedule 1: Cost Allocation

Preamble:

The range approach for revenue to cost ratios was adopted by the Board due to "influencing factors", such as data quality, that may not make a revenue to cost ratio of one practical in all cases. However, the Board said that "to the extent 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." It has now been four years since the initial cost allocation studies were done. In the current evidence HON still proposes revenue to cost ratios for a number of rate classes that are far below or above unity (for example, Streetlighting, at 0.7, UGSe, at 1.2, and UGSd, at 1.25).

Questions:

(a) Are there data quality or other issues within HON's control that prevent HON from moving the above-mentioned rate classes closer to 1? If so, please explain what they are and what HON has done to eliminate them.

(b) Please provide the amount by which the UGSe and UGSd will be over-contributing to HON's revenue requirement in 2010, and what that number represent on a per customer basis within each rate class.

Response

(a) There are still data issues for Residential and General Service energy billed customers since the load profiles for these types of customers are still based on load research data and not on actual customer data for the class. Once data is collected through smart meters, better quality hourly data will be available for these customers that should improve the quality of the data and may allow the OEB to issue new guidelines with respect to acceptable revenue to cost ratios by customer class.

(b) The following table shows the difference in the revenue requirement for 2010 contributed by the UGe and UGd classes, between using the proposed cost ratios and a cost ratio set to 1.

	(Revenue Requirement - Allocated Costs)	(Revenue Requirement - Allocated Costs) / Number of customers
UGe	$ 1,770,900	$ 167
UGd	$ 3,139,544	$ 2,778

School Energy Coalition (SEC) INTERROGATORY #46 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1

Please confirm that the sole principal author of the study is John Todd. Please file his curriculum vitae.

Response

Confirmed. John Todd's CV is available at www.era-inc.ca.

School Energy Coalition (SEC) INTERROGATORY #47 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1
Please file the terms of reference for the study, and any written instructions or guidance given to the consultant at any time between the issuance of the terms of reference and the filing of the final report as an exhibit in this proceeding.

Response

Attachment 1: (e-mail dated April 21, 2009, 9:39 am) was the first communication with the Consultant. The attachments referred to in the e-mail are the OEB Decision on Proceeding EB-2007-0681 dated December 18, 2008 that can be found on the OEB Website and the Power Point presentation, is the presentation made by Michael Roger at the first Stakeholder Session on April 15, 2009. This presentation can be found on Hydro One's external Website under Regulatory Affairs, Distribution Rate Application, 2010/2011 Stakeholder Discussion Sessions, April 15, 2009. Hydro One also filed a report on the Stakeholder Sessions that can be found in Exhibit A, Tab 17, Schedule 1.

Attachment 2: is the above Power Point presentation.

Attachment 3: is the second e-mail dated April 21, 2009, 10:10 am which includes comments sent to Hydro One by FOCA and a copy of the letter sent by Hydro One to the OEB related to Density Study, dated April 20, 2009, following the first Stakeholder Session. The letter is included in Exhibit H, Tab 1, Schedule 123.

Attachment 4: is the third e-mail dated April 29, 2009, 9:11 am which includes a description from the Consultant on the estimated resources that would be needed for the May 2009 Stakeholder presentation. The blacked out information is confidential information provided by the consultant related to cost estimates for the contract.

Hydro One also shared with the Consultant the Meeting Notes for the April 15, 2009 Stakeholder Consultation Session.

From: ROGER Michael
Sent: Tuesday, April 21, 2009 9:39 AM
To: 'John Todd'
Cc: ANDRE Henry; COWAN Allan
Subject: RE: Accepted: Density Study - Principles

Hi John: Attached are two documents:

1. The Power Point presentation is what I presented to the Stakeholders last Wednesday explaining how currently we define the density based customer classes and how we developed the density weights used to allocate costs to the customer classes
2. The PDF file is the OEB decision dated December 18, 2008 on our 2008 Distribution rate application. The section dealing with Density is from page 28 to page 31 of the OEB Decision, (the section is titled The Proposed Cost Allocation), and the OEB direction is on top of page 31 of the OEB Decision.

At our meeting on Thursday afternoon I will go over the Power Point slides to explain how we do Density now.

If you have any questions, please let me know.

Mike

From: John Todd [mailto:JTodd@ERA-INC.CA]
Sent: Tuesday, April 21, 2009 9:27 AM
To: ROGER Michael
Subject: Accepted: Density Study - Principles

That is perfect Mike. I look forward to reviewing the material you will be sending prior to our meeting.

Density/Cost Allocation Study

April 15, 2009



Michael Roger

Manager, Distribution Pricing

hydro one

OEB Direction

OEB Decision page 31

- Detailed analysis on the relationship between density and cost allocation
- Whether the customer class demarcations offer the best reflection of cost causation
- Consideration of alternative density weightings

Current Density Definition

- Urban Density Zone is defined as areas containing 3,000 or more customers with a line density of at least 60 customers per kilometre. (156,000 Residential customers)

- Medium Density Zone is defined as areas containing 100 or more customers with a line density of at least 15 customers per kilometre. (365,000 Residential customers)

- Low Density Zone is defined as areas other than Urban or Medium Density Zone. (358,000 Residential customers)

Density Weighting Factors

- Used to allocate Overhead Lines and Transformer related costs
- Two Components:
  - Customer Density weighting factors (allocation of fixed costs)
  - Demand Density weighting factors (allocation of variable costs)

Overhead Line Costs

- Customer density weights based on number of customer by class for each feeder
- Demand density weights based on energy by customer class by feeder

Example

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: Total Customers		**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/customer**	**0.81**	**0.50**	**0.65**
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

Density Weights Overhead Lines

	Customer	Demand
	For Fixed costs	For Variable costs
UR	0.19	0.18
R1	0.66	0.64
R2	1.61	1.42
Seasonal	1.20	1.60
GSe	1.11	1.15
GSd	1.14	1.18
UGe	0.24	0.18
UGd	0.31	0.30
Dgen	1.00	1.00
ST	1.00	1.00
St Lgt	1.00	1.00
Sen Lgt	1.00	1.00

Transformer Costs

- Customer density weights based on NBV of transformation assets by class for each feeder
- Demand density weights based on energy by customer class by feeder

Density Weights Transformers

	Customer	Demand
	For Fixed costs	For Variable costs
UR	0.77	0.75
R1	0.93	0.88
R2	1.23	1.12
Seasonal	0.87	1.28
GSe	1.00	1.04
GSd	1.05	1.01
UGe	1.03	0.79
UGd	0.76	0.94
Dgen	1.00	1.00
ST	1.00	1.00
St Lgt	1.00	1.00
Sen Lgt	1.00	1.00

Current Rate Issues

- In 2010 will still be in the middle of the 4 year Harmonization plan
- Continued Rate Pressure due to Smart Network and DG connections
- OEB Staff Paper on proposed Rate Design

Question # 1

1. Should “customer density” be a consideration in defining customer classes?

Question # 2

2. What criteria are relevant for defining customer classes?

Question # 3

3. How should “density” be considered in allocating costs to the various classes?

-----Original Message-----
From: ROGER Michael
Sent: Tuesday, April 21, 2009 10:10 AM
To: 'John Todd'
Cc: COWAN Allan; ANDRE Henry
Subject: FW: Consultation on Density Issues

John: FYI, below is one perspective from FOCA on the Density Study. Also I am attaching a letter we sent the OEB last Friday.

Mike

-----Original Message-----
From: John McGee [mailto:mcgeejs@csolve.net]
Sent: Wednesday, April 15, 2009 7:26 PM
To: FRANK Susan
Subject: Consultation on Density Issues

Susan;
I wanted to pass on further comments about issues raised by the SEC both at the 2009 rate application hearing and the mtg today.
An overriding issue is that schools, unlike most other customer groups are financed from the public purse.
So getting absolute precision in school rates, by means of expensive studies, is of no consequence to other consumer groups. We all pay their costs thru taxes or other means.

So I strongly support your view to minimize costs on studies to re-jig cost and density allocators to satisfy a group we all pay for anyway.

FOCA is quite happy to participate in Hydro One consultation sessions.
We no longer intervene in OEB rate hearings, because of the very high time commitment and cost to all of your customers.

John McGee

ROGER Michael

From: ROGER Michael
Sent: Wednesday, April 29, 2009 9:11 AM
To: 'John Todd'
Cc: COWAN Allan; ANDRE Henry
Subject: RE: Density Study

John: I do not need a revised description of the work, just making it clear in the slides is sufficient.

Mike

From: John Todd [mailto:JTodd@ERA-INC.CA]
Sent: Wednesday, April 29, 2009 9:08 AM
To: ROGER Michael
Cc: COWAN Allan; ANDRE Henry
Subject: RE: Density Study

Good point. I will clarify.

Would you like a revised description of the work, or shall I just make it clear in the slides I am currently preparing and will be sending to you later today?

Cheers,

John D. Todd
(416) 348-9910

From: mike.roger@HydroOne.com [mailto:mike.roger@HydroOne.com]
Sent: April-29-09 8:59 AM
To: John Todd
Cc: allan.cowan@HydroOne.com; henry.andre@HydroOne.com
Subject: RE: Density Study

John: Our only comment is whether the 2nd issue of "factors that drive the relationship between density and cost allocation" is being addressed. This was how the 2nd issue has been framed in the discussions and correspondence so far.

Perhaps the last couple of items are meant to address this? If so, you should probably be more explicit in how you frame the issue. Even if you do not have a lot to say at this stage, you should as a minimum talk about how you plan to tackle the issue going forward.

Thanks,

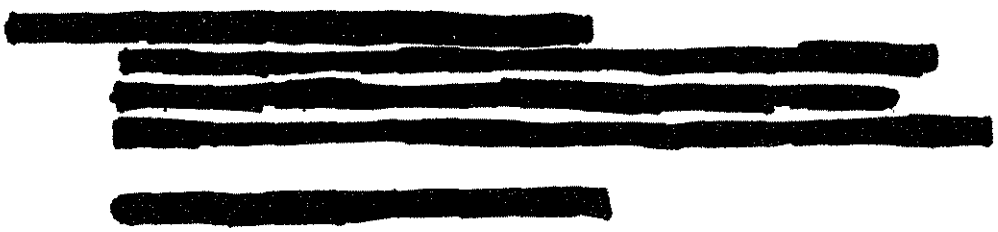
Mike

From: John Todd [mailto:JTodd@ERA-INC.CA]
Sent: Tuesday, April 28, 2009 2:11 PM
To: ROGER Michael

Subject: Density Study

Mike, as discussed last week, this email sets out my estimate for the resources (time and cost) that will be incurred in preparing a presentation for the May 26 Stakeholder Sessions that will address the principles for defining residential sub-classes based on customer density. The presentation will include:

- A brief overview of the use of density as a basis for residential customer sub-classes in the past (Canadian telecom/CRTC (competitive consideration) and California electric utilities in the 1950's); why were they used? Why discontinued? Lessons for Ontario today.
- A brief overview of identified literature/policy studies that have addressed relevant issues (density-based rates; basis for defining classes/subclasses) E.g., Goodman, pp. 416-417 and 1017-1019
- Consistency of density rates (based on cost differences) with Bonbright Principles
- Possible methodologies for defining density-based sub-classes
- Practical methodologies for determining the cost of service by sub-class
- Magnitude of cost differentials
- The role of explicit cross-subsidies to balance the "cost-of-service" and "fairness" principles (what is fair?)



ERA will invoice Hydro One Networks monthly based on actual time incurred as set out in the purchase order.

Mike, please let me know if you require anything further or more formal.

Cheers,

John D. Todd, President
Elenchus Research Associates Inc.
Suite 600, 34 King St. East
Toronto, ON M5C 2X8
(416) 348-9910

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Link to our monitoring service at www.cerise.info
(Canadian Energy Regulation Information Service)

****
This message is intended for use only by the individuals to whom it is specifically addressed and should not be read by, or delivered to, any other person. Such communication may contain privileged or confidential material. If you have received this message in error, please notify us immediately by return email (jtodd@era-inc.ca). We thank you in advance for your co-operation and assistance.
****

School Energy Coalition (SEC) INTERROGATORY #48 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 1

Please confirm that the study is not intended to be in full compliance with the Board's direction at page 30-31 of EB-2007-0681, and that further steps would be required to complete compliance with that direction.

Response

Yes, Hydro One confirms that the study is not intended to be in full compliance with the Board's direction and further steps would be required.

Please refer to Exhibit H, Tab 1, Schedule 123.

School Energy Coalition (SEC) INTERROGATORY #49 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 1, 5 and others

Please confirm that the consultant took into account, in addition to the input provided at stakeholder meetings, the detailed critique of the current cost allocation and rate classification approach provided by School Energy Coalition in its EB-2007-0681 final argument.

Response

Confirmed.

School Energy Coalition (SEC) INTERROGATORY #50 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 4

Please confirm that the Rural or Remote Rate Protection system already in place is intended to provide the same type of cross-subsidy as the HCSA concept. If there are differences in the goals of the two approaches, please describe those differences. Please advise whether the consultant believes that RRRP provides an insufficient subsidy for rural and remote customers of the Applicant.

Response

Please see Exhibit G1, Tab 2, Schedule 5, Attachment 1, Section 2.1.1 where HCSA is explained.

School Energy Coalition (SEC) INTERROGATORY #51 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 6

Please confirm that, in the consultant's view, the principles that apply to designing rates within a class are the appropriate principles to apply in determining which customers to group together within a class.

Response

Confirmed. In the context of the discussion referenced in the question (Section 3 of the report), it may be noted that section 3.3 includes the following statement, "It follows that the same principles serve as the basis for defining customer classes and for cost allocation." Of course, as the report goes on to discuss in section 3.4, the considerations and details related to how these principles are applied in practice are different for defining customer classes and for designing rates.

School Energy Coalition (SEC) INTERROGATORY #52 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 6

Please confirm that, in the consultant's view, the principle of cost causality is the primary and most important principle to be used in establishing rate classes. If other principles are also to be applied, please describe how those principles (e.g. fairness, efficiency) should be weighed against the principle of cost causality, and how differences in results from applying different principles should be resolved.

Response

The statement in the question is not confirmed. In the consultant's view, there is no overriding hierarchy of principles rather it is always necessary to use judgment in balancing any conflicting principles in a manner that results in just and reasonable rates. In particular, cost causality is not an easy principle to apply. For example, common costs are allocate in various ways that are intended to reflect cost causality principles, although the way in which the various customer classes "cause" common costs is open to debate.

School Energy Coalition (SEC) INTERROGATORY #53 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 7, 13

Please advise which cost differentiation principles or criteria, in addition to "require different categories of facilities" and "have different load profiles" are appropriate for use in establishing rate classes, and which of those additional principles are currently used in rate classification for Ontario LDCs.

Response

Ontario LDCs have a short history of formal regulation although the established rate classes have a long history. As a result, there is no documentation of the principles used to establish the rate classifications that are currently used.

The view of the consultant is set out in section 3.2 Principles for Defining Customer Classes which states:

> "In applying both the broad ratemaking principles and the more specific rate design principles to the even narrower issue of defining customer class, it appears that the essential principle for defining customer classes is to ensure that "like customers are being treated in a like manner", in the words of OEB staff, or in the words of Bonbright et al., equals are treated equally and unequals are treated unequally."

School Energy Coalition (SEC) INTERROGATORY #54 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 9, 10

Please advise whether, in the opinion of the consultant, rates should be different at all for rural and urban customers in the Applicant's franchise area. If the answer is that they should not, please provide a summary of how the consultant has balanced the points raised on these pages to reach that conclusion.

Response

This issue is addressed in the Report at section 7.1 Should Separate Urban and Rural Classes be Maintained which contains the following conclusion:

> "I therefore conclude that generally accepted ratemaking principles provide very limited support for maintaining separate urban and rural classes on the basis of differences in customer or demand densities that affect causal costs."

The reasoning for this conclusion is contained in section 7.1.

School Energy Coalition (SEC) INTERROGATORY #55 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 9, 10

Please provide copies of all provisions in proposals, agreements, letters of intent, disclosure documents, or other written materials related to the acquisition of or merger with any of the Acquired LDCs, or any other electricity distributor at any time, that make any representations, warranties, commitments or other statements (including but not limited to public statements at meetings, to political bodies, or to the press) with respect to future rates in the relevant franchise area. Please include any restrictions, agreements, or other provisions in which the Applicant became limited in any way in the rates it could charge or apply for in any geographic area, whether or not those restrictions, agreements or other provisions are currently still applicable. Where any of the representations, warranties, commitments, other statements, restrictions, agreements, or other provisions referred to above can only reasonably be understood in the context of other materials (such as the remainder of the document), please provide the full document, in confidence if necessary.

Response

Please refer to RP-2005-0020/EB-2005-0378; Exhibit H, Tab 4, Schedule 59, a copy of which is attached. This previous Interrogatory Response addresses all rate commitments made in acquisition agreements by Hydro One up to the present time.

RP-2005-0020/EB-2005-0378 – EXHIBIT H, TAB 4, SCHEDULE 59

Energy Probe (EP) INTERROGATORY #59 List 2

Interrogatory

Reference: Ex. G1, Tab 2, Sch. 1

Please provide all agreements, public assurances, or any other commitments undertaken with respect to rates applicable to the customers of Acquired Utilities as part of any purchase agreements entered into by Hydro One.

Response

Provided are the relevant excerpts from the Purchase and Sale Agreements for each utility purchased by Hydro One Networks. The agreements are commercial and are not binding on the Board.

Ailsa Craig

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Arkona

4.8 *Distribution Rates*: The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Arran- Elderslie

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Artemesia

4.12 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current customers, for the period to be covered by the Buyer's first rate order after s.26(1) of the Electricity Act, 1998 comes into force (hereinafter referred to as "Open Access").

Blandford Blenheim

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Blyth

4.10 The Buyer shall utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to

supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Carleton Place

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Centre Hastings

4.10 The Buyer shall, when appropriate and with notice to the Sellers, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Municipality, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Chalk River

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current customers, for the period to be covered by the Buyer's first rate order after Open Access.

Clarence-Rockland

4.11 The Buyer shall, when appropriate and with notice to the Sellers, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to

establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Sellers could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Cobden

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for urban distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Deep River

4.9 The Buyer shall, when appropriate and with notice to the Sellers, utilize their reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the customers that would be equivalent to those rates that the Commission or Town, as the case may be, could have charged if it continued to supply the current customers, for the period to be covered by the Buyer's first rate order after Open Access.

Deseronto

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Dryden

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the

Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Durham

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Eganville

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Forest

4.9 *Distribution Rates*: The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Georgina

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electricity to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Grand Bend

4.9 *Distribution Rates*: The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Greater Napanee

4.11 The Buyer shall, when appropriate and with notice to the Sellers, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Town , as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Hastings

4.11 The Buyer shall utilize its reasonable efforts to obtain approval from the Ontario Energy Board to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be,

could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Havelock-Belmont-Methuen

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Lanark Highlands

4.11 The Buyer shall utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Larder Lake

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Latchford

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to

establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Lucan Biddulph

4.9 The Buyer, at its own expense, shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Malahide

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Mapleton

4.11 Subject to the matters contained in the third bullet contained on Page 3 of the executed Letter of Intent between the parties hereto dated August 2, 2000, the Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

- Hydro One Networks' commitment from the end of the rate freeze until 2003, despite expected increases and decreases in individual charges, is to work toward

the goal that the total paid by all customers in the municipality in aggregate will not increase.

Markdale

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Marmora

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

McGarry

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Meaford

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for

distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Middlesex Centre

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Nipigon

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

North Dorchester

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Seller could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

North Dundas

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

North Glengarry

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

North Stormont

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Percy - Walkworth

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Rainy River

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Ramara

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Red Rock

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Russell

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the System or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Schreiber

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Shelburne

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

South Bruce Peninsula - Wiarton

4.11 The Buyer shall, when appropriate and with notice to the Sellers, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Company could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

South Glengarry

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

South River

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Southgate - Dundalk

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Seller could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Springwater

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Thedford

4.9.1 *Distribution Rates*: The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy

to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Tweed

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

West Elgin

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

West Nissouri

4.10 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access.

Wyoming

4.9 The Buyer shall, when appropriate and with notice to the Seller, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates that would place the current Customers within a bandwidth of comparable municipalities as defined by the Ontario Energy Board in an attempt to establish rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current customers, for the period to be covered by the Buyer's first rate order after Open Access.

Arnprior

4.10 The Sellers shall make reasonable efforts to obtain prompt leave of the Ontario Energy Board (the "OEB") pursuant to s. 86(1) of the *Ontario Energy Board Act, 1998*, so as to enable the Closing to occur prior to a date when the transaction will attract the transfer tax referred to in s. 5.2(d) below. Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until open access is declared or December 31, 2000, whichever comes first; (b) once open access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges. The Buyer also covenants that it will not increase the rates or fees charged to Customers for hot water heater rental or sentinel light rental, or the energy price for street lighting, where any such increases would be effective in 2000.

Bancroft

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing

residential and General Service energy rates at their existing level until Open Access is declared or June 30, 2001, whichever comes first; (b) once Open Access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Bobcaygeon

6.5 Rate Setting

(a) All rates applicable to customers of the Corporation will be subject to OEB requirements and approval.

(b) The Purchaser commits to freeze existing Residential and General Service energy rates of the Corporation at their existing level until Open Access is declared or until June 30, 2001, whichever comes first. Once Open Access is declared, all electricity customers of the Corporation will see unbundled charges appear on their bills. The bills will have a standardized OEB-regulated distribution wires charge and all customers will have the choice of shopping for energy by contracting with a competitive energy retailer or making no choice, thereby remaining with the Purchaser.

(c) The Purchaser’s commitment from the end of the rate freeze, referred to in paragraph (b) above, until 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers of the Corporation in aggregate will not increase.

(d) Although the Purchaser feels confident about its plan, the Parties acknowledge that that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers’ total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

Caledon

6.8 Temporary Rate Freeze

(a) The Purchaser commits to freeze the Corporation's existing Residential and General Service energy rates at their existing level until OEB approved unbundled rates come into effect or June 30, 2001, whichever comes first.

(b) Once the market opens, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Purchaser.

(c) The Purchaser's commitment until the effective date of the rate order expected in 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers in the municipality in aggregate will not increase.

(d) Although the Purchaser feels confident about its plan, it must be recognized that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB approved wires access charges.

(e) All rates shall be subject to OEB approval.

Cambellford - Seymour

6.5 **Rate Guarantee.** Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, The Purchaser hereby covenants and agrees:

(a) to freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or December 31, 2000, whichever comes first;

(b) the Buyer's commitment from the end of the said freeze until 2003 is to work toward the goal that the total paid by all customers in aggregate will not increase;

(c) provided that it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained

with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Cavan-Millbrook-North Monaghan

6.8 Rate Setting

(a) All rates applicable to customers of the Corporation will be subject to OEB requirements and approval.

(b) The Purchaser commits to freeze existing Residential and General Service energy rates of the Corporation at their existing level until Open Access is declared or until June 30, 2001, whichever comes first. Once Open Access is declared, all electricity customers of the Corporation will see unbundled charges appear on their bills. The bills will have a standardized OEB-regulated distribution wires charge and all customers will have the choice of shopping for energy by contracting with a competitive energy retailer or making no choice, thereby remaining with the Purchaser.

(c) The Purchaser's commitment from the end of the rate freeze, referred to in paragraph (b) above, until 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers of the Corporation in aggregate will not increase.

(d) Although the Purchaser feels confident about its plan, the Parties acknowledge that that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

Champlain

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or June 30, 2001, whichever comes first; (b) once Open Access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward

the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB- approved wires access charges.

Exeter

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or June 30, 2001, whichever comes first; (b) once Open Access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Fenelon Falls

6.8.0 Rate Setting

(a) All rates applicable to customers of the Corporation will be subject to OEB requirements and approval.

(b) The Purchaser commits to freeze existing Residential and General Service energy rates of the Corporation at their existing level until Open Access is declared or until June 30, 2001, whichever comes first. Once Open Access is declared, all electricity customers of the Corporation will see unbundled charges appear on their bills. The bills will have a standardized OEB-regulated distribution wires charge and all customers will have the choice of shopping for energy by contracting with a competitive energy retailer or making no choice, thereby remaining with the Purchaser.

(c) The Purchaser's commitment from the end of the rate freeze, referred to in paragraph (b) above, until 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers of the Corporation in aggregate will not increase.

(d) Although the Purchaser feels confident about its plan, the Parties acknowledge that that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

Glencoe

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or June 30, 2001, whichever comes first; (b) once Open Access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB- approved wires access charges

Kirkfield

6.8.1 Rate Setting

(a) All rates applicable to customers of the Corporation will be subject to OEB requirements and approval.

(b) The Purchaser commits to freeze existing Residential and General Service energy rates of the Corporation at their existing level until Open Access is declared or until June 30, 2001, whichever comes first. Once Open Access is declared, all electricity customers of the Corporation will see unbundled charges appear on their bills. The bills will have a standardized OEB-regulated distribution wires charge and all customers will have the choice of

shopping for energy by contracting with a competitive energy retailer or making no choice, thereby remaining with the Purchaser.

(c) The Purchaser's commitment from the end of the rate freeze, referred to in paragraph (b) above, until 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers of the Corporation in aggregate will not increase.

(d) Although the Purchaser feels confident about its plan, the Parties acknowledge that that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

Lindsay

6.9 Rate Setting

(a) All rates applicable to customers of the Corporation will be subject to OEB requirements and approval.
(b) The Purchaser commits to freeze existing Residential and General Service energy rates of the Corporation at their existing level until Open Access is declared or until June 30, 2001, whichever comes first. Once Open Access is declared, all electricity customers of the Corporation will see unbundled charges appear on their bills. The bills will have a standardized OEB-regulated distribution wires charge and all customers will have the choice of shopping for energy by contracting with a competitive energy retailer or making no choice, thereby remaining with the Purchaser.
(c) The Purchaser's commitment from the end of the rate freeze, referred to in paragraph (b) above, until 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers of the Corporation in aggregate will not increase.
(d) Although the Purchaser feels confident about its plan, the Parties acknowledge that that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

Loyalist

4.10 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or June 30, 2001, whichever comes first; (b) once Open Access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

North Perth

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the Ontario Energy Board, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or June 30, 2001, whichever comes first; (b) the Buyer's commitment from the end of the said freeze until 2003 is to work toward the goal that the total paid by all customers in aggregate will not increase; and (c) it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Omemee

6.8 Rate Setting

(a) All rates applicable to customers of the Corporation will be subject to OEB requirements and approval.
(b) The Purchaser commits to freeze existing Residential and General Service energy rates of the Corporation at their existing level until Open Access is declared or until June 30, 2001, whichever comes first. Once Open Access is

declared, all electricity customers of the Corporation will see unbundled charges appear on their bills. The bills will have a standardized OEB-regulated distribution wires charge and all customers will have the choice of shopping for energy by contracting with a competitive energy retailer or making no choice, thereby remaining with the Purchaser.

(c) The Purchaser's commitment from the end of the rate freeze, referred to in paragraph (b) above, until 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers of the Corporation in aggregate will not increase.

(d) Although the Purchaser feels confident about its plan, the Parties acknowledge that that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

Perth

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until open access is declared or June 20, 2001, whichever comes first; (b) once open access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Perth East

4.10 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until open access is declared or June 30, 2001, whichever comes first; (b) once open access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the

OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Prince Edward

4.11 The Buyer shall, when appropriate and with notice to the Seller, utilise its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that the Commission or Seller, as the case may be, could have charged if it continued to supply the current Customers, for the period to be covered by the Buyer's first rate order after Open Access**.**

4.24 *Subject to the fact that all energy rates will be subject to the approval and requirements of the Ontario Energy Board (the "Board"),*

(a) the Buyer shall freeze the existing residential and General Service energy rates of the Commission until the market is declared open or June 30, 2001, whichever comes first;

(b) upon market opening, all electricity customers will see unbundled charges on their energy bills. The bills will have a standardised distribution wires charge, regulated by the Board, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remain with the Buyer;

(c) the Buyer commits that from the end of the freeze referred to in (a) until 2003, despite expected increases and decreases in individual charges, the Buyer will work toward the goal that the total charges for distribution services paid by all customers in the three communities serviced by the Commission in the County of Prince Edward will not increase; and

(d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity

commodity, and the total of the bills for individual customers may vary with the spot market price of electricity or based on the deals obtained with a competitive electricity retailer, as well as because of Board approved wires access charges.

Quinte West

6.11 Rates

(a) The Purchaser shall review the rate treatment of its own customers in the former Sidney and Murray Townships that are on the periphery of the former Town of Trenton and former Village of Frankford and, where applicable and subject to OEB approval, move the rates for customers to its urban density rate class where the conditions are met for this rate class.

(b) The Purchaser commits to freeze the Commission's existing Residential and General Service energy rates at their existing level until OEB-approved unbundled rates come into effect or June 30, 2001, whichever comes first.

(c) Once the market opens, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Purchaser.

(d) The Purchaser's commitment until the effective date of the rate order expected in 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers in the municipality in aggregate will not increase.

(e) Although the Purchaser feels confident about its plan, it must be recognized that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

(f) All rates shall be subject to OEB approval.

Smiths Falls

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until open access is declared or June 20, 2001, whichever comes first; (b) once open access commences, all electricity customers will see unbundled charges appear on their

bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Stirling-Rawdon

.1 **Rate Guarantee**. Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, The Purchaser hereby covenants and agrees:

(a to freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or December 31, 2000, whichever comes first;

(b the Buyer's commitment from the end of the said freeze until 2003 is to work toward the goal that the total paid by all customers in aggregate will not increase;

provided that it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Wardsville

4.10 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until Open Access is declared or June 30, 2001, whichever comes first; (b) once Open Access commences, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until 2003, despite expected increases and decreases in individual charges is to work toward the goal that the total paid by all customers in the Municipality in aggregate will not

increase; and (d) although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Woodville

6.8 Rate Setting

(a) All rates applicable to customers of the Corporation will be subject to OEB requirements and approval.

(b) The Purchaser commits to freeze existing Residential and General Service energy rates of the Corporation at their existing level until Open Access is declared or until June 30, 2001, whichever comes first. Once Open Access is declared, all electricity customers of the Corporation will see unbundled charges appear on their bills. The bills will have a standardized OEB-regulated distribution wires charge and all customers will have the choice of shopping for energy by contracting with a competitive energy retailer or making no choice, thereby remaining with the Purchaser.

(c) The Purchaser's commitment from the end of the rate freeze, referred to in paragraph (b) above, until 2003, despite expected increases and decreases in individual charges, is to work toward the goal that the total paid by all customers of the Corporation in aggregate will not increase.

(d) Although the Purchaser feels confident about its plan, the Parties acknowledge that that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well because of OEB-approved wires access charges.

Brighton

5.12 Rate Application

The Vendor shall forward to the Purchaser copies of all material in the Vendor's possession pertaining to the Rate Application. The Vendor shall, having consulted with the Purchaser, cause the Corporation to file the Rate Application with the OEB on or before November 30, 2000 or such later date as may be permitted by the OEB, which will request a maximum market based rate of return, subject to any commitment made by the Purchaser to the Vendor in respect of rates. The Vendor shall co-operate with the Purchaser in making the Rate Application as provided herein and in responding to the

OEB in connection with any responses received from the OEB relating to the Rate Application or any amendment or refiling thereof. Save and except for the filing of the Rate Application as provided in this Section 5.12, the Vendor shall not, and shall not permit the Corporation or the Commission to, file any other rate application or any amendment, supplement or replacement to the Rate Application without the prior written consent of the Purchaser.

Brockville

6.9 Rate Setting

(a) Recognizing the fact that charges for the delivery of electrical energy will be subject to approval and requirements of the OEB,

(b) the Purchaser shall freeze the electrical rates applicable to all existing or new electricity distribution customers (ie. residential and general service) located within the electricity distribution area of the Business as of the date of this Agreement at the existing level charged by the Corporation until Open Access is declared or June 30, 2001, whichever comes first;

(c) the Purchaser's commitment, from the end of the above-mentioned freeze until implementation of second generation PBR (expected in 2003), is to set the local electricity distribution charge to ensure that the average electricity bills paid by customers of the Business in any rate classification will not increase;

(d) this commitment is based on a projected average commodity price of 3.8 cents/kWh over the year, however, the Purchaser cannot guarantee the price of commodity and commodity related charges as these will be a direct pass through based on spot market or as obtained by customers through a competitive retailer.

(e) The Vendor and the Corporation shall file the First Generation Rate Application for Brockville by the November 30, 2000 filing date after consultation with the Purchaser.

(f) Following Closing, the Purchaser shall be responsible for making any rate applications or submissions regarding the Business to the OEB required to be made by the Purchaser to ensure that rates for Year 2 and Year 3 of the First Generation PBR honour the rate guarantee as outlined in Section 6.9(a).

(g) The Purchaser shall provide to the City and the Vendor sufficient information and assistance to allow a clear understanding of any rate submissions or adjustments relating to the Business or its customers and proposed by the Purchaser or its affiliates prior to submission to the OEB. If the City and the Vendor are not satisfied that the intent of Section 6.9(a) has been met, there are no restrictions on the Vendor taking appropriate

action to address the situation, including application and representation to the OEB.

Erin

7.5 Rate Structure.

(a) **Freeze on Existing Rates** - The Purchaser covenants that it shall freeze the Commission's existing residential and general service energy rates, as set out in Schedule 10, until Open Access is declared or until December 31, 2000, whichever comes first.

(b) **Customer Electricity Bills** - The Purchaser shall use its best efforts to ensure that until January 1, 2003, there will be no overall increase in the electricity bill of the current customers of the Commission.

Georgian Bay

6.10 Rate Structure

(a) The Purchaser commits to freeze the Corporation's existing bundled Residential, General Service and large User rates at their existing level until OEB approved unbundled rates come into effect.

(b) The Purchaser's commitment until the effective date of the first rate order which is expected in 2003, is to work to ensure that customers do not see an increase in their overall electricity bill. The Purchaser will work towards the goal that the total paid by all customers of the Corporation will not increase.

North Grenville

4.11 Subject to the fact that all energy rates will be subject to the approval and requirements of the OEB, (a) the Buyer shall freeze the Commission's existing residential and General Service energy rates at their existing level until open access is declared or June 20, 2001, whichever comes first; (b) once open access commences, all electricity customers will see unbundled charges appear on their bills; the bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Buyer; (c) the Buyer's commitment from the end of the above-mentioned freeze until implementation of second generation PBR (expected in 2003), is to set the local electricity distribution charge to ensure that the average electricity bills paid by customers of the Business in any rate classification will not increase; and (d)

although the Buyer feels confident about its plan, it must be recognized that the Buyer does not have any influence over the price of the electricity commodity, and individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer, as well as because of OEB-approved wires access charges.

Severn

6.5 Rate Structure

(a) All rates are subject to OEB requirements and approval. The Purchaser will not seek an adjustment in the Purchase Price in response to an OEB decision regarding approval of the Purchaser's rate application.

(b) The Purchaser commits to freeze the Commission's existing unbundled Residential and General Service rates at their existing level until OEB-approved unbundled rates come into effect or June 30, 2001, whichever comes first.

(c) Once the market opens, all electricity customers will see unbundled charges appear on their bills. The bills will have a standardized distribution wires charge, regulated by the OEB, and all customers will have the choice of shopping for energy by contracting with a competitive electricity retailer or simply remaining with the Purchaser.

(d) The Purchaser's commitment until the effective date of the first rate order (expected in 2003) is to ensure that customers do not see an increase in their overall electricity bill. In other words, despite expected increases and decreases in the individual charges, the Purchaser will work toward the goal that the total paid by all customers in the Township of Severn will not increase. Although the Purchaser feels confident making this commitment, it must be recognized that the Purchaser does not have any influence over the price of the electricity commodity. Individual customers' total bills may vary with the spot market price of electricity or based on the deal obtained with a competitive electricity retailer.

(e) From the effective date of the first rate order expected in 2003 onwards, the appropriate OEB-approved density-based rates would apply.

Thorold

No Rate Commitment in Commercial Agreement.

Whitchurch - Stouffville

6.7 Rate Guarantee. Notwithstanding anything provided in Section 5.5 (Rate Application), the Purchaser hereby covenants and agrees:

(a) The Rate structure levels established April 1, 1999 under the OEB's Transitional Distribution Rate Order EB-1999-0190 applicable to all electricity distribution customers (eg. residential, general service, etc.) who are now or in the future located within the Corporation's electricity distribution area as it was delineated on that date will be frozen until the earlier of the proclamation of Section 26 of the EA ("Market Opening") or June 30, 2001.

(b) After the date established in Section 6.7(a), the Purchaser will be allowed to adjust the Rate structure and Rate levels to reflect the components and characteristics of a customer's total unbundled electricity bill as it would appear post Market Opening provided that, before Market Opening, the overall amount of revenue collected from customers by the Purchaser shall be no greater than the amount of revenue collected as of December 31, 1999, based on similar amounts of electricity used by each customer.

(c) After Market Opening and until the OEB Rate Order based on the second generation of performance based regulation in 2003, the Purchaser will continue to limit the revenues collected from customers (eg. residential, general service, etc.) to the same levels as of December 31, 1999 and this limit will be reflected to each customer so as that, although the unbundling adjustments were performed under Section 6.7(b), the total revenue envelope paid by each customer will be frozen to the same level as of December 31, 1999 (for example an amount of $76.63 per 1000 Kwh per month paid by residential customers as of December 31, 1999 would be frozen at $76.63 per 1000 Kwh per month after Market Opening), provided that the total revenue envelop would vary under the following conditions specific to the customer: the customer changes the amount of electricity consumed, the customer switches to another supplier of the electricity commodity, or a significant industry event results in a dramatic increase in the Purchaser's cost of electricity that is provided to the customer.

(d) The Rates for the Corporation's customers who are now or in the future located within the Corporation's electricity distribution area, as delineated on April 1,1999, who border on the area currently served by electricity

distribution by the Purchaser will be lower than the rate for customers served by the Purchaser outside the area of the Corporation and this relationship will be fixed until the OEB Rate Order based on the second generation of performance based regulation in 2003.

(e) Two months after the OEB Rate Order based on the second generation of performance based regulation in 2003, the Purchaser shall provide the Vendor with a report as to how the Purchaser met the objectives set out under this Subsection 6.7(e) and its impact on customer rates.

Thessalon

4.10 The Buyer shall, when appropriate and with notice to the Sellers, utilize its reasonable efforts to obtain approval from the Ontario Energy Board for distribution rates for the distribution of electrical power and energy to the Customers that would be equivalent to those rates that Thessalon Hydro could have charged if it continued to supply the current Customers for the period to be covered by the Buyer's first rate order.

School Energy Coalition (SEC) INTERROGATORY #56 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 11

Please confirm on behalf of the Applicant that the following statements of the consultant are correct:

> *"There does not appear to be any significant documentation of the original basis for this definition [Urban Density Zone."*
>
> *"No record of the basis of the line density criterion of 60 customers/km is available."*

Response

Hydro One confirms that the two statements by the consultant are correct.

School Energy Coalition (SEC) INTERROGATORY #57 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 12

Please advise whether, under the current system, the boundaries of zones change as population changes, or only the classification of existing zones will change.

Response

Under the current system the boundaries of the zone or cluster changes as population changes (customer/km^2) or if there is a change in number of connections per length of a line (customers/km of line).

School Energy Coalition (SEC) INTERROGATORY #58 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 13

Please advise why, if 'there is no analytic support for the appropriateness of these criteria [the breakpoints] at this time", the option of continuing the status quo is presented as a possibility by the consultant. Please advise the rationale for continuing the status quo in the consultant's opinion. Please provide support for the statement "the status quo criteria are directionally correct and may be as good as any alternative set of criteria".

Response

The rationale is provided immediately after the quote from page 13. The Report states:

> "Certainly there is no analytic support for the appropriateness of these criteria at this time. The primary justifications for retention of the existing criteria would include the following. These justifications are pragmatic rather than principled.
>
> a) Any change in definition would create winners and losers (i.e., some customers would enjoy rate reductions while others would experience rate increases). Research has shown that the perception of harm for a financial loss is greater than the perception of gain for a comparable financial benefit. It could be argued that any "tweaking" of the criteria would be disruptive to customers, could result in rate instability, and would not result in any aggregate net gain for customers.
>
> b) Any revision to the existing class definitions that retains criteria based on density would be unlikely to increase simplicity and transparency for the typical residential customer, would be unlikely to eliminate the apparent arbitrariness of the dividing lines as the relationship between cost of service and density is most likely a continuum with no obvious break-point. Furthermore, the relationship between customer density and cost of service is almost certainly to be weakened by the numerous other factors affecting cost of service such as the distance to other distribution facilities and the transmission system, the local terrain, the age of assets, etc. Separating out the unique impact of density on cost of service will be a very difficult and expensive task if it is done with a reasonable degree of precision and credibility.
>
> c) Overall, while no criteria will be perfect for differentiating customers on the basis of customer density, as a rough indicator of higher, medium and

lower cost of service residential customers, the status quo criteria are directionally correct and may be as good as any alternative set of criteria.

d) Maintaining the status quo in terms of the definition of density-based classes will avoid the cost and disruption of developing and implementing alternative cost based criteria.

e) To the extent that the existing differences in rates are more reflective of the rate differentials that are deemed to be just and reasonable for customers that are essentially the same in all respects other than the customer density in their area, any effort to determine the true underlying cost differences may be of little relevance. In an environment that views Rural or Remote Rate Protection to be an appropriate policy, it would appear that the rate differentials for the residential classes will be limited to what is deemed to be equitable, rather than being determined by the true underlying cost differences. If that is the case, it is difficult to see any benefit in undertaking a study to better understand the relationship between customer density and cost of service, when it could be considered inequitable to use the results as the basis for setting rates in any case."

School Energy Coalition (SEC) INTERROGATORY #59 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 13

Please confirm that changes to the existing class definitions that reduce urban rates would have the effect, in most of the Acquired LDCs, of reversing a portion of the increases currently being implemented for harmonization.

Response

Changes to existing class definitions that reduce urban rates would have the effect of reversing a portion of the increase currently being implemented for harmonization, but not to most of the Acquired LDCs. Only 11 of the 88 Acquired LDCs have customers that were classified as Urban.

School Energy Coalition (SEC) INTERROGATORY #60 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 14, 15

Please advise what criteria should, in the consultant's view, be used to determine the appropriate level of granularity for establishment of rate classes.

Response

The quoted section of the report concludes as follows:

> "Based on the foregoing observations, it can be concluded that any attempt to redesign HOD's current approach to make it more consistent with the fairness principle by classifying customers on a more granular basis will create practical difficulties that will be expensive and onerous to address. While there may be conceptual merit in adopting an approach that provides for a more intuitive division of customers into urban and rural classes, the practical reality is that a simplified approach, while imperfect, is almost certainly in the best interest of customers overall."

The point is that while various highly granular methodologies could be developed, they would be expensive and the costs would ultimately be recovered from customers. The entire cost allocation process is based on the adoption of simplified methods that capture important differences in causal costs without being so granular as to be impractical. If that were not the case, costs would be determined on a customer specific basis. The entire concept of classes is a method used to ensure that the rate-setting process is not unduly onerous.

School Energy Coalition (SEC) INTERROGATORY #61 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 17

Please explain why the DCF model would change if the urban/rural split changes. If possible, please provide an example. If any part of the reason for the change is that the DCF model does not use forecast costs for an actual project, please estimate the extent to which changing the urban/rural rate classes would make the DCF results more or less accurate.

Response

The first sub-bullet under the Feasibility Test (DCF Model) bullet states, "DCF uses estimated construction cost for actual projects but standardized values for future costs (e.g., maintenance, customer service, etc.)". Future costs other than the actual project costs are based on standardized values. For example, future maintenance and customer service costs are based on standardized values, not project specific estimates. Clearly a significant change in the split between the urban and rural classes could have an impact on the standardized maintenance and customer service costs for the classes. To illustrate, if rural customers that are close to urban centres are reclassified as urban customers, the average maintenance urban and rural travel time, and hence standardized urban and rural maintenance costs, would both increase.

School Energy Coalition (SEC) INTERROGATORY #62 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 19

Please confirm that, in the consultant's opinion, the current cost allocation methodology used by the Applicant to allocate costs between urban and non-urban rate classes a) does not allocate all material costs that are different between the two areas, and b) allocates those it does address based on weightings that are not conceptually correct.

Response

The characterization at page 19 of the report is as follows:

> "While this methodology is reasonable in that more precision is not achievable with currently available data, it is acknowledged that the approach is not conceptually ideal.'

The point being made is that Hydro One relies on a proxy methodology for the reasons stated in the report. By definition, any proxy methodology will not allocate all costs to classes and will not rely on allocations that are conceptually correct. Rather a proxy is intended to provide a reasonable approximation of a more precise (and more costly) methodology.

In the consultant's view, a methodology that allocates "all material costs" to classes in a manner that is "conceptually correct" in that it precisely measures causal costs (the consideration considered to be of primary importance in question 52 as posed), is not necessarily the preferred option taking into account the cost involved in implementing the methodology and other ratemaking principles.

School Energy Coalition (SEC) INTERROGATORY #63 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 20, 23

Please confirm that the primary purpose of the methods described in Section 5.2. is to identify relationships between costs and measurable cost drivers, so that the cost drivers can be used to allocate costs. If this is not correct, please explain.

Response

Four alternatives are considered in section 5.2. The first methodology would directly allocate costs at a highly disaggregated level directly to the urban and rural classes, which are geographically distinct. The remaining three methods are intended "to identify relationships between costs and measurable cost drivers, so that the cost drivers can be used to allocate costs" as suggested.

School Energy Coalition (SEC) INTERROGATORY #64 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 22

Please advise whether any regression analyses have been done by the consultant or the Applicant, whether a full study as described here, or any partial studies with a similar intent or direction. If they have, please provide copies.

Response

No full or partial regression analysis studies have been done by the consultant or Hydro One.

School Energy Coalition (SEC) INTERROGATORY #65 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 24

Please advise whether the consultant did any independent analysis of costs that might be higher or lower in urban vs. non-urban areas, or whether all of the factors listed are the opinion of the Applicant's engineering staff. If the consultant carried out an independent analysis, please provide details of how that was carried out, and the results.

Response

The consultant did not undertake any independent analysis of costs differences in urban and rural areas. The factors identified at page 24 of the report are based on interviews with Hydro One engineering staff using what was essentially a focus group process facilitated by the consultant.

School Energy Coalition (SEC) INTERROGATORY #66 List 1

Interrogatory

Density-Based Rates

Reference: Exhibit G1/Tab 2/Schedule 5, Attach. 1, page 27, 28

Please advise whether the consultant considers a combination of sample data and engineering analysis to be a suitable method of compensating for the shortfalls of each approach.

Response

As is stated in section 5.2.4, the engineering analysis methodology is "conceptually different" from the other methods in that it would derive cost difference for distribution infrastructure that is identical in all respects other than density, while the other approaches identify cost differences for Hydro One Networks Inc.'s urban and rural areas (without attempting to adjust for other systematic differences between urban and rural areas). Because sample data and engineering analysis are measuring different things, the conceptually appropriate way to combine the methods is not obvious.

It would be more appropriate for the Board to provide guidance as to the conceptual approach that it prefers (i.e., the cost differences between Hydro One Networks Inc.'s urban and rural service areas as approximated by sample data, or the hypothetical cost difference attributable to density based on engineering analysis).

ELECTRICAL CONTRACTORS ASSOCIATION OF ONTARIO (ECAO)
INTERROGATORY #1 List 1

Interrogatory

Reference: Ex. ANTI5/S8, p. 3 and p. 8; Ex. A/T161S], p. 8] The evidence references Hydra One's need to contract out a greater volume of distribution work in support of its capital investment plans, including its proposed *Green Energy Act* plan. The evidence also mentions labour agreement constraints to contracting out.

a) Please provide a copy of any written Hydro One policy regarding contracting out of electrical design, engineering and construction work.

b) Please provide copies of any labour agreement provisions to which Hydro One is subject and which impact or limit the extent to which Hydro One can contract out electrical design, engineering or construction work.

c) The evidence posits that all categories of external resources are becoming hard to contract as North American demand increasingly exceeds available supply. Please detail any Hydro One policies or initiatives to maintain or enhance the quality and quantity of available external electrical design, engineering and construction work resources.

d) Please provide, for each of 2008, 2009, 2010 and 2011, the costs incurred/forecast for external electrical design, engineering and construction work contracts and the total costs (for both external and internal resources) for this work. For 2010 and 2011 please divide the provided costs figures between *Green Energy Act* plan related costs and *non-Green Energy Act Plan* related costs.

Response

a) There are no policies with respect to contracting out of electrical design, engineering and construction work.

b) Please see Attachment 1 and Attachment 2.

c) Hydro One has developed specialized power system training programs to increase the supply of suitably trained specialist engineering staff in future years. These are currently offered at the following universities:
- University of Waterloo
- University of Western Ontario
- McMaster University
- Ryerson University

Hydro One has established a consortium of four colleges to offer the college curriculum necessary to prepare for a career as an Area Distribution Technician in the Electrical Utility Sector. The participating colleges are Mohawk, Georgian, Algonquin, and Northern.

There is a Provincial Lines/Power Workers' Union Hiring Hall Apprenticeship Program. The jointly organized program is a 4 year apprenticeship that, when successfully concluded, provides Power Line Technician status. The formal training is delivered by the Hydro One training group which is a recognized Training Delivery Agency (TDA) by the Ministry of Trades, Colleges and Universities (MTCU). The successful technicians go on to work for Hydro One, other utilities, and other external firms.

d) Our financial reporting systems do not provide the granularity to split external work between electrical design, engineering and construction work. The requested information available is provided below.

Total R1 - Prov Lines, E&CS, Stations, External - $M

	Total Net Cost*	GEA**	NON-GEA	Contract Costs	GEA	NON-GEA
2008	$321			$19		
2009	$345			$21		
2010	$392	$17	$375	$44	$13	$31
2011	$455	$34	$421	$78	$17	$61

**Does not include Operations or Shared Services*

***GEA work per Tables 4 and 5 in Exhibit D1-3-3. Gross GEA work is $168M in 2010 and $296M in 2011.*

Collective Agreement
Between
Hydro One
and
Power Workers' Union
Canadian Union of Public Employees
C.L.C. Local 1000
April 1, 2008 - March 31, 2011

ARTICLE 12
PURCHASED SERVICES AGREEMENT

12.0 SCOPE

This Article has been developed jointly in a spirit of co-operation and trust. It is intended to provide a joint approach to making good business decisions which involve the use of purchased services. Its application calls for these decisions to be made in the same spirit of co-operation and trust.
What follows is based upon the belief that there is a value and benefit to the employee, the co-operation and the customer if:

· There is a greater involvement by employees in the decision-making process.
· There is an improved understanding as to why purchased services are used.
· Employment security is enhanced by a productive, healthy, and cost effective organization.
· Union and Management work together and act responsibly, balancing the interests of the customer, the Company and the employee in decisions relating to the use of purchased services.

This is a way of deciding how work gets done. It is not intended to hinder getting work done.

12.1 Assignment Of Work

12.1.1 Philosophy

It is the Company's intent to use regular staff to perform most of its work of a continuing nature. Furthermore, the Company will strive to provide regular staff with stability of employment.
The parties agree that a consistent, managed and joint approach to the assignment of work within the Company is necessary to provide security for employees, a more effective, productive organization and an excellent product for the customer.

12.1.2 Principles

The following principles apply to the relationship between the Company and the Union and the work performed by Union members.

(a) We will within the Company have all work conducted as effectively as possible.
(b) We will measure the effectiveness of all work by its impact on staff, on the business and by its ultimate impact on our customers.
(c) We will do most work of a continuing nature with Company employees.
(d) We will determine when work is to be done by non-PWU members through a joint decision making process and the results of these decisions will be a joint responsibility.
(e) We will ensure that the impact of these decisions on continuous employment is minimized.
(f) We will use a team and consensus approach when making decisions and any issues arising will be resolved internally where possible.
(g) We will consult and make timely decisions consistent with the need to get work done.
(h) We will develop, implement and continue a joint process of communications and education.
(i) We will achieve consistency through the use of these principles versus policy and procedure.

12.2 Decision Process (See Mid-Term Agreement MT-50 also)

12.2.1 Responsibility for Decisions

The persons who are responsible for applying the decision process are the Company representative with the appropriate decision authority and the Union representative designated by the Sector Vice President. It is recognized that a given decision may require the involvement of more than these two persons.
Subject to 12.2.6 and 12.3.2(c) below, decisions to use purchased services will be made on a consensus basis. Both parties must consider all relevant criteria with the mutual goal of selecting the most effective option.
The decision makers are responsible for making timely decisions and for the decision itself.

12.2.2 Opportunity

The parties recognize that work may be done more effectively internally or externally. Opportunities for the application of this Article to new or existing work can be initiated by Management and/or the Union. It is intended that joint discussion should commence as soon as possible and before detailed definition of the need to have new or existing work done by purchased services.

12.2.3 Definition of Need

The parties will consider what work must be done and why and include such dimensions as when it must commence and the duration of the work; the quantity of resources required; the quality of the results; the skills required and their availability internally and externally; and safety requirements.

12.2.4 Alternatives

The parties will consider such alternatives as, do the work internally; do part of the work internally and part externally; do the work externally and agree to acquire capability to do the work internally in future; or do the work externally.

12.2.5 Evaluation

The parties will evaluate the alternatives considering the impact on the customer, employees and the business. Such criteria as reliability of service to the customer, customer responsiveness, community impact, Company relations impact, job continuity, ability to perform work, degree of overtime required for the work, availability of resources, cost, timeliness, quality, need for control over results, safety and impact on environment will be assessed.
The total effectiveness of the alternatives will be evaluated considering both the short and long-term impacts. In given situations, certain criteria may be given a greater or lesser degree of importance.

12.2.6 Establishment of Thresholds

The establishment of the threshold is designed to remove from the process on a case by case basis certain issues relating to purchased services. The threshold will operate in such a way as to allow flexibility in local decision making. Any decisions regarding what is below the threshold will be non-precedent setting.
If there is a dispute with the union on whether the proposed purchased service is permitted by the threshold and there is no consensus, and if it makes sense in the circumstances the dispute will be resolved before the purchased service occurs. Lack of agreement on obtaining an advance resolution will not preclude the work from being performed, neither will it preclude the matter from being resolved under the 12.2.7 process.
The guidelines to determine whether a purchased service is below the threshold are as follows:

· subject matter lacking in substance; or
· any consequences are relatively insignificant; or
· where the nature or consequences of the work which represents a purchased service is remote from work currently performed by the PWU on a continuing basis. For purposes of clarity, this does not mean geographically remote; or
· emergencies; or
· any work performed under a manufacturer's warranty, except where the manufacturer authorized the Company to do the work.

Except in the case of an emergency, failure by the Company to supply the Union with the following information by fax or as otherwise agreed will result in the work in question being deemed to be above threshold. (In the case of emergency such decisions to use purchased services will be subject to the same information requirements, review and dispute resolution as non-emergency cases).
The Company will notify the Union of the:

· Value of Work as reflected in Tender/Contract/Bid or Estimate Documents
· Scope of the Work
· Location of Work
· Estimated Date of Commencement and Duration of the Work

Except in the case of emergency, after receipt of the above information regarding the work the union shall have three (3) working days to request an opportunity to discuss the proposed purchased service, failing which the proposed purchased service will be deemed to be below threshold.
The parties will make themselves available for discussion within three (3) working days of the request for a discussion.
Upon request, once the work has been performed the Company will provide the Union with the details of the final contract costs.

(a) Threshold grievances will be completed by the Chief Steward responsible for the PSA and presented to the line Management person responsible for the work in question.
(b) Line Management must respond in writing to the grievance citing its position within 48 hours (as is required with all other grievances). Both parties should endeavour locally to complete a Record of Discussion form or an agreed statement of fact sheet.
(c) The PWU office will assign a grievance number. Copies of the completed grievance and associated fact sheets or Records of Discussion forms should be sent to the PWU office and Labour Relations - Corporate Human Resources.
(d) Grievances will be referred to Arbitration and scheduled through joint agreement between Labour Relations - Corporate Human Resources and the PWU office.
(e) If it makes sense to do so, local discussions may take place with a view to resolving the threshold grievance up to the arbitration date.

12.2.7 Dispute Resolution Process

(a) Mr. Teplitsky shall be appointed as Facilitator to assist the parties to resolve all issues of application and interpretation of this Article with the power and authority of an arbitrator under the Ontario Labour Relations Act but not subject to the Arbitrators' Act.
(b) Any dispute between the parties relating to whether this Article applies to any decision to use purchased services or if a purchased service falls within the categories set out in 12.2.6 will be determined in an expedited manner by the facilitator whose decision shall be final and binding.
(c) The Union will not be prejudiced in any subsequent case by a particular purchase of services. Similarly, the Company will not be prejudiced by any decision not to purchase services. This applies to all cases including threshold cases.

12.3 Joint Resolution Committee

12.3.1 Purpose

The purpose of this Joint Committee is to resolve disagreements, on a consensus basis in a timely and expeditious manner, as to whether proposed purchased services which are above threshold above may proceed. In its deliberations, the committee will consider the factors in items 12.0, 12.1 and 12.2.
Prior to a meeting of the Joint Committee, the Company will provide the Union with the following information related to the proposed PSA:

· copies of the Tender or Request for Proposal documents, if there are any;
· an accurate description of the work which is the subject of the proposed PSA;
· accurate details on bids e.g., price, scope of the work as set forth in the bid;
· a full cost benefit analysis including incremental costs but excluding overhead costs which would be incurred.

12.3.2 Membership

The membership of the Joint Committee shall be as follows:

(a) The facilitator Mr. Teplitsky who shall act as Chairperson;
(b) One Management and one union representative plus additional resources as required.
(c) In the event of the parties not being able to reach a consensus decision the facilitator will have the power to make decisions. Mr. Teplitsky will have the authority to make such orders as he deems appropriate to give full affect to his decision(s) and to deal with any consequences his decision(s) might have in the workplace.
(d) Where either party wishes to proceed with a Purchased Services discussion which is above threshold, the parties will endeavour to complete discussion within 10 days of notice to the union in the prescribed form and that full resolution, including review by the JRC, will occur within 30 days of notification.

12.4 Application of This Article

12.4.1 The parties will jointly develop and maintain an operating plan consistent with the provisions of this Article. Such plans will be approved by the appropriate Company official and the Power Workers' Union Vice President. Failure to jointly develop an operating plan will not adversely affect either party's rights under the provisions of this Article.
These operational plans will include:

· An approach for the development and delivery of joint training of decision makers
· An identification of the type of contracts that are not subject to an in-depth review.
· A guideline for a time table on how often contracts of a recurring nature must be reviewed under this Article.
· A process for joint review of potential contracts which involve work normally

performed by PWU represented employees and other stakeholders.
· A process and a time frame for decision making.
· An internal process for dispute resolution.

12.4.2 Management and Union representatives may choose to jointly review the application of their operating plan and determine the need for changes at any time over the life of this agreement.

12.4.3 Until ***March 31, 2008***, Article 13, Article 14, Mid-Term Agreement MT-12 Contracting Out, MT-21, MT-21 Appendix A, and Mid-Term Agreement MT-14 Future Agency Employees are suspended. Item 12.1 of this Article will apply to decisions regarding the use of agency employees.

COLLECTIVE AGREEMENT
Between
Hydro One Inc.
and
The Society of Energy Professionals

67 PURCHASED SERVICES

(Suspended for term of the collective agreement except for the last bullet).

67.1 Approvals

67.4.1 Blanket annual PSA approval will be given for each organization headed by a direct report to the President at the beginning of each calendar year subject to the following conditions:

- ***Hydro One commits to use regular staff for most core work;***
- ***External resources will be primarily used for work such as supplementing peaks, responding to new business opportunities, low value work, non-recurring work etc.;***
- ***Hydro One commits to enhancing and maintaining skill level of staff;***
- ***As soon as possible and in any event no later than early in the calendar year each direct report to the President will review and discuss the staffing strategy with the Society Hydro One Local Vice-President for the purpose of trying to reach a common understanding with respect to the strategy. If a common understanding cannot be reached, management will make the final decision;***
- ***Each direct report to the President will provide to the Society at the end of the calendar year a list of contracts let during the year including total contract dollars;***
- ***No employee will be laid off as a direct result of contracting out.***

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #1
List 1

Interrogatory

Issue 1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

Reference: Exh A/Tab 16/Sch 1

Part of the Board's direction to Hydro One on compensation was "to improve on its cost allocation accounting processes with the objective of being able to demonstrate improvements in efficiency and the value for dollar associated with its compensation costs."

a) Please identify what specific changes Hydro One has made in its cost allocation accounting processes that will enable identification of improvements in the cost efficiency of work.

b) Has Hydro One made accounting changes that will enable it to identify labour cost efficiency improvements by project, program, or work order? For example, can Hydro One now identify trends in the labour cost efficiency of line clearing or recloser maintenance?

c) If Hydro One has not made changes to its accounting processes to accommodate comparison of cost efficiency related to compensation, please indicate if such changes are planned, what level of detail will be available (e.g., by program, work type, work order, etc.) and if so, when they will be operational.

Response

a) b) and c)

Hydro One is currently able to specifically identify or allocate cost to Transmission and Distribution in its accounting and planning systems and processes. The work based approach and standard costing approaches have been discussed in both the previous Transmission and Distribution rate hearings. In addition, the common cost allocation methodology has been extensively reviewed. Further improvements to systems that will provide both additional details on costs and more lead to other efficiencies are as follows;

- Phase 2 of the Cornerstone initiative included modules on Finance, HR, Pay, Time reporting and a reporting warehouse. These elements, working in coordination with

the Phase 1 Work Management and Accounts Payable Modules, now provide Hydro One with an integrated system across these areas. This integrated approach will provide Hydro One with greater visibility to accounting, accomplishment, staffing/compensation information which it believes will lead to efficiency improvements.

- In addition, although Phase 3 is still in the detailed scoping phase it is anticipated that it will contain several analytical modules that, in combination with the ERP systems in place will allow Hydro One to make better decisions regarding investments (i.e. type, timing and locations). These better decisions will allow Hydro One to achieve the savings attributed to the Cornerstone initiative as discussed in Exhibit D1 – 3- 7.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #2
List 1

Interrogatory

Issue 2.1: Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

Reference: Exh A/Tab 14/Sch 4/Page 9, lines 9-20

Please provide Hydro one's estimates for CDM results over the period 2006-2010, broken out by the causes listed (i.e., Hydro One Programs, OPA programs, Self-motivated) as per the anticipated consultant's report.

Response

The attached report (Attachment 1) entitled "Net Load Impact Analysis of Conservation and Demand Management" prepared by Hydro One provides detailed estimates of CDM results over the period 2006-2008 and expected program results for 2009. Program result estimates for 2010 are not available at the present time; please see Exhibit H, Tab 4, Schedule 5 for expected Hydro One programs in 2010.

Net Load Impact Analysis of Conservation and Demand Management

September, 2009

1.0 Overview

This report presents a bottom-up analysis of Conservation and Demand Management (CDM) impact using information as of September 2009. The analysis was prepared by Hydro One's load forecasting staff to help assess the CDM impact on the load forecast.

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)

Year	Hydro One Programs (1)	OPA Programs (2)	Federal and Provincial Government Programs (3)	Annual Program Savings (1-3)	Cumulative Program Savings (1-3)	Additional Impact from Customer Conservation Actions
2005	9	n/a	64	73	73	At least 170
2006	147	6	67	221	294	
2007	105	61	62	228	522	
2008	9	49	60	118	640	
Total	**270**	**116**	**253**	**640**		**170**

Note: N/A denotes not available. CDM impacts are shown at the wholesale purchase level.

Table 1 summarizes the CDM impact on Hydro One retail load since 2005. Compared to the CDM impact forecast used in EB-2009-0096 (see Appendix A for details), the analysis in this report shows that the CDM forecast for Hydro One retail customers is

conservative. Based on the analysis undertaken in this report, CDM program results for Hydro One retail customers have exceeded the CDM forecast for 2008.

Table 2: CDM Impact Analysis for Embedded LDC Customers (GWh)

Year	LDC Programs (1)	OPA Programs (2)	Federal and Provincial Government Programs (3)	Annual Program Savings (1-3)	Cumulative Program Savings (1-3)	Additional Impact from Customer Conservation Actions
2005	19	n/a	39	58	58	At least 150
2006	57	3	36	95	153	
2007	39	21	39	99	252	
2008	2	23	39	64	315	
Total	**116**	**47**	**152**	**315**		**150**

Note: N/A denotes not available. CDM impacts are shown at the wholesale purchase level.

Table 2 summarizes the CDM impact analysis for the embedded LDC customers (see Appendix J for details). Similar analysis cannot be undertaken for the embedded direct customers due to lack of information. In 2007, program results from Hydro One Distribution's Double Return program for embedded direct customers are estimated to be about 24 MW for the winter months and 20 MW for the summer months. The Double Return program achieved a further reduction of 16 MW from embedded direct customers in the summer of 2008. Based on the analysis undertaken in this report, CDM program results for embedded LDC customers have exceeded the CDM forecast for 2008.

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 for 2005-2007. After the 3rd tranche funding, Hydro One Distribution relies on the OPA managed funds from the Global Adjustment Mechanism for its CDM initiatives in 2008 and beyond.

Table 3 summarizes the CDM impact resulting from programs initiated by Hydro One Distribution (see Appendix B for more details). These results are based on the annual CDM results submitted by Hydro One Distribution to the OEB each year.

Table 3: Net Load Impact of CDM Programs Initiated by Hydro One Distribution

Year	Annual Peak Savings (MW)	Annual Energy Savings (GWh)	Cumulative Energy Savings (GWh)
2005	0.6	8.6	8.6
2006	10.8	146.9	155.5
2007	58.8	105.3	260.8
2008	3.2	9.1	269.9

Note: CDM impacts are shown at the wholesale purchase level.

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 the 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 description 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 6 GWh, 61 GWh and 49 GWh for 2006, 2007 and 2008 respectively. Detailed OPA program impacts 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 in Canada. Aside from setting the overall energy policy, the department plans to spend over $300M during 2007-2010 on energy efficiency programs of various types. The Government of Ontario also implements a number of CDM programs, such as the Home Energy Savings program. There are at least 30 federal and provincial government-initiated CDM programs in Ontario each year, with an estimated impact of 64 GWh, 67 GWh and 62 GWh on Hydro One Distribution retail customers in 2005, 2006 and 2007 respectively. The program impact for 2008 is not yet available, but is expected to be in the same range as in previous years. Details of programs offered by the federal and provincial government 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, such as Energy Efficient Premium Refund program offered by Canada Mortgage and Housing Corporation (CMHC). 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, the 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 two studies to measure the conservation actions of customers. The first study is an econometric analysis to measure the net impact of CDM programs for 2004-2008 using the hourly load profile analysis approach. This is the same methodology used in Hydro One's Transmission 2009-2010 rate application (EB-2008-0272). The second study is an analysis to measure customer conservation actions using customer billing data. Again, this is the same methodology used in Hydro One's Distribution 2008 rate application (EB-2007-0681). The results of these two studies show that there are additional energy savings attributed to conservation actions from our retail customers (see Appendix G for details).

In 2009, Hydro One undertook another CDM survey to assess the conservation actions undertaken by our customers. Of the 9,450 customers who received the survey invitation, 2,829 customers (30%) 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. The survey results support the findings of the econometric analysis and the customer billing analysis discussed above.

5.0 CDM Programs for 2009

At the time this report was prepared, final CDM program results for 2009 are not yet available. In 2009, Hydro One Distribution expects to spend $1 million from distribution rates on administration of CDM work, $1.4 million from the Ontario Ministry of Energy and Infrastructure for a renewable energy pilot (PowerHouse) program and $15.5 million from the LDC fund administered by the OPA. Table 4 below illustrates the expected

spending, participants, savings (MW and MWh) and TRC Net Benefits of conservation programs, which will have an impact on Hydro One retail customers.

Table 5: 2009 Conservation Programs

2009 Forecast					
YEAR 2009	**2009 Forecasted Expenditure (program costs + incentives) ($K)**	**ESTIMATED PARTICIPANTS (customers or units)**	**2009 est. ANNUAL SAVINGS (MWh)***	**2009 est. SAVINGS (MW)***	**Hydro One's portion of TRC Net Benefit 2009 ($K)***
Rate Funded Administration of CDM Work					
Maintenance of MARR Funded Programs and Minimum Capability	$ 1,000	Not available	Not available	Not available	Not available
Ministry of Energy Funding					
PowerHouse program	$ 1,400	153	(501)	0	$ 2,815
Global Adjustment Mechanism Funding - OPA Core Program					
Electricity Retrofit Incentive Program*	$ 2,650	160	12,900	3.6	$ 8,476
Great Refrigerator Roundup	$ 500	23,000	11,400	1.3	$ 1,708
PeakSaver	$ 4,125	7,500	2,000	7.0	$ 10,463
Power Savings Blitz**	$ 7,100	5,350	20,000	5.8	$ 4,149
Global Adjustment Mechanism Funding - OPA Custom Program					
Double Return	$ 1,200	119			
Distribution		111	44,280	19.6	$ 2,159
Transmission		8	70,831	22.5	$ 3,614
Total	**$ 17,975**	**36,282**	**160,911**	**59.8**	**$ 33,384**

** Assumptions for various technologies and programs not yet finalized by OPA; EM&V will commence in 2010*

Source: Estimates prepared by Hydro One Distribution using best available information from OPA as of September, 2009. Please note that all numbers are shown at customer end-use level.

Beyond 2009, Hydro One Distribution supports the CDM target for the province and will contribute towards meeting that target. Appendix K provides further details of future program to be offered by the OPA and Hydro One.

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), 2007 (EB-2007-0681) and 2009 (EB-2009-0096).

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.

Table A4: CDM Forecast (in GWh) used in EB-2009-0096

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
2006	194	151	345
2007	311	245	557
2008	432	340	771
2009 (Bridge)	601	471	1,072
2010	1,325	1,035	2,360
2011	1,604	1,249	2,853

Note: CDM impacts are shown at the wholesale purchase level.

The CDM forecast was updated (see Table A4) in April 2009. Hydro One Distribution's 2008 CDM impact was approved by the Board in its Decision on December 18, 2008 for EB-2007-0681. The CDM impacts for 2009, 2010 and 2011 are based on Hydro One Distribution's share of approximately 15 percent of the provincial CDM target consistent with the IPSP filed by the OPA with the Board on August 29, 2007. The aggregate provincial CDM target from the IPSP for 2008-2010 was approved by the Board in Hydro One's 2008 Transmission Rate case (EB-2008-0272).

Appendix B: Summary of CDM Program Results Initiated by Hydro One Distribution

This appendix summarizes the CDM program results for Hydro One retail customers since 2005. Tables B1 to B5 provide a "bottom up" view of the CDM impact between 2005 and 2008 by program and sector.

Table B1: CDM 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. Please note that all savings in this table are shown at the customer end-use level. Annual energy savings for 2005 are approximately 9 GWh at the wholesale purchase level.

Table B2: CDM 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 2006 CDM Annual Report, Appendix B.

Source: Hydro One Networks Inc. Conservation and Demand Management Plan Annual Report, Appendix C to December 31, 2006, RP-2004-0203\EB-2005-0198 filed April 2nd, 2007. Please note that all savings in this table are shown at the customer end-use level. Together with 48.79 GWh and 0.13 MW of savings assigned by the OPA in July 2009 for the Every Kilowatt Counts program (not shown in Table B2), total annual energy savings for 2006 attributed to Hydro One Distribution programs are approximately 147 GWh at the wholesale purchase level.

Table B3: CDM 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, Appendix B.

Source: Hydro One Networks Inc. Conservation and Demand Management Plan Annual Report, Appendix C to December 31, 2007, RP-2004-0203\EB-2005-0198 filed March 31st, 2008. Please note that all savings in this table are shown at the customer end-use level. Together with 31.45 GWh and 1.62 MW of savings assigned by the OPA in July 2009 for the Every Kilowatt Counts program (not shown in Table B3), total annual energy savings for 2007 attributed to Hydro One Distribution programs are approximately 105 GWh at the wholesale purchase level.

Table B4: CDM Program Results for 2008

PROGRAM	3 YEAR BUDGET(5) ($k)	LTD SPENDING 2008 ($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(**1**)	2,465	2,467	6,681	103,475,092	673,451,075
Seasonal LED Light Exchange	430	432	-	546,454	16,393,624
Low Income / Social Housing(**2**)	3,200	3,167	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 (Power Saver Plus Online Energy Audit)	215	213			
Subtotal	25,035	24,872	25,921	139,855,336	971,147,149
Commercial/Industrial, Farm, MUSH					
Interim Time of Use	1,130	1,145	-	-	-
C/I MUSH Conservation(**3**)	1,040	1,015	2,207	15,404,813	217,294,721
C/I Load Control (Double Return)	2,390	2,339	33,773	108,854,220	108,898,068
Farm Energy Efficiency(**4**)	510	458	349	1,970,695	17,454,329
Subtotal	5,070	4,958	36,329	126,229,728	343,647,118
Common					
Distribution Loss Reduction	6,175	6,552	4,998	14,444,110	288,882,198
Program Management and Research (incl. TOU Pilot)	2,500	2,425	43	396,185	3,248,037
Communication and Education (incl. Smart Pak)	765	749	140	3,649,933	30,145,133
Carrying Charge		25	-	-	-
Subtotal	9,440	9,752	5,181	18,490,228	322,275,368
Total	39,545	39,581	67,431	284,575,292	1,637,069,635

Notes:

1 Mass Market includes Cold Shoulder Appliance Pickup, Every Kilowatt Counts, PowerSaver Tour, Mass Market Coupon Initiative, Keep Cold and Cool Shops Program

2 Low Income/Social Housing includes Low Income Retrofit, Low Income CMHC / NRCan, First Nations Retrofits, First Nations In-Home Displays and Social Housing Programs

3 C/I MUSH conservation includes PowerSaver Business Incentive Program (Commercial / Industrial), Toronto Region Conservation Authority, Municipal Traffic Signal LED

4 Farm Energy Efficiency includes PowerSaver Business Incentive Program (Farm), Leamington and Farm Energy Audit

5 The Budget has been reallocated from approved plan and the reallocations are within 20% flexibility allowed by the Board

Source: Hydro One Networks Inc. Conservation and Demand Management Plan Annual Report, Appendix C to April 30, 2008, RP-2004-0203\EB-2005-0198 filed March 31st, 2009. Please note that all savings in this table are shown at the customer end-use level.

Table B5: Incremental CDM Results for 2008

PROGRAM ACTIVITIES	2008 Incremental Expenditures ($K)	PEAK SAVINGS (kW)	ANNUAL SAVINGS kWh	LIFECYCLE SAVINGS kWh
Maintenance of current programs				
Residential				
Cold Shoulder Appliance Pickup	16	23	119,809	1,084,806
Load Control Program	78	-	-	-
PowerSaver Plus Online Energy Audit	60	-	-	-
Low Income/Social Housing				
Low Income/Social Housing	46	15	108,904	2,178,073
Commercial/Industrial, Farm, MUSH				
PowerSaver Business Incentive Program	1	1	6,868	112,086
C/I Load control (Double Return)	104	7	168,245	3,364,891
Interim Time of Use	43	-	-	-
Farm Load control (Leamington DG)	51	-	-	-
Maintenance of current programs Subtotal	399	46	403,825	6,739,856
PowerHouse Pilot Program Subtotal	200	5	(107,890)	(2,157,799)
Program Management and Research				
- Survey	33	-	-	-
- Research	214	-	-	-
- Education	2	-	-	-
Program Management and Research Subtotal	249	-	-	-
Total	848	51	295,935	4,582,057

Source: Hydro One Networks Inc. Conservation and Demand Management Plan Reporting of Incremental CDM Funding Approved in Rates, Appendix C filed April 30th, 2009. Please note that all savings in this table are shown at the customer end-use level. Annual energy savings are approximately 9 GWh at the wholesale purchase level.

Appendix C: Summary of OPA-Initiated Program Results

This appendix summarizes the OPA program results for Hydro One Retail customers for 2006, 2007 and 2008. Latest program savings allocated to Hydro One were provided by the OPA in July 2009. Allocation methods used by the OPA are summarized as follows:

- For LDC-delivered programs, savings were allocated based on participation data that was tracked by individual LDCs.
- For third party (non-LDC delivered) programs, savings were allocated to corresponding LDC territory when LDC-specific geographic data on program participation was readily available. When LDC-specific geographic data on program participation was not readily available, savings were allocated based on each LDC's share of the provincial energy consumption for the customer class targeted by the program, based on data from the OEB Yearbook of Electricity Distributors.

Table C1 presents the share assumptions for Hydro One Distribution retail and embedded LDCs.

Table C1: Share Assumption from OEB Yearbook of Electricity Distributors

	Hydro One Retail		Embedded LDC	
Year	Residential Energy Throughput (%)	Non-Residential Energy Throughput (%)	Residential Energy Throughput (%)	Non-Residential Energy Throughput (%)
2005	30.1%	12.7%	12.3%	8.5%
2006	30.4%	12.7%	12.4%	7.7%
2007	30.7%	12.5%	12.4%	8.9%
2008	30.6%	12.4%	12.2%	8.8%

The five OPA-coordinated CDM programs in 2006 resulted in annual savings of 407 GWh and summer peak reduction of approximately 217 MW. Table C2 below presents the province-wide savings and the savings allocated to Hydro One Distribution retail customers.

Table C2: OPA-Initiated Program Results in 2006

OPA Program	Total Provincial Annual GWh Savings	Total Provincial Annual MW Savings	GWh Savings Assigned to Hydro One Retail Customers	MW Savings Assigned to Hydro One Retail Customers
Every Kilowatt Counts *	385.9	4.6	117.4	1.4
Cool Savings Rebate	11.2	11.5	3.4	3.5
Hot Savings Rebate	4.0	3.2	1.2	1.0
Secondary Refrigerator Retirement	6.0	1.4	1.8	0.4
Demand Response 1	0.0	196.2	0.0	24.9
Total	**407.2**	**216.8**	**123.9**	**31.0**

Source: OPA 2006 Conservation Bureau Annual Report.
Note: *The results from Every Kilowatt Counts were already included in the CDM Annual reports shown in Table B2. The additional energy and peak savings not yet reported in the CDM Annual report are about 6.5 GWh and 29.7 MW respectively.

In 2007, OPA-coordinated CDM programs resulted in province-wide annual savings of approximately 333 GWh and peak reduction of 469 MW. Table C3 below summarizes the energy and peak impacts allocated to Hydro One Distribution retail customers.

Table C3: OPA-Initiated Program Results in 2007

OPA Program	Total Provincial Annual GWh Savings	Total Provincial Annual MW Savings	GWh Savings Assigned to Hydro One Retail Customers	MW Savings Assigned to Hydro One Retail Customers
Every Kilowatt Counts *	142.3	5.5	43.7	1.7
Great Refrigerator Roundup	14.6	1.7	5.8	1.1
Cool Savings Rebate	32.5	21.4	10.0	6.6
Aboriginal – Pilot	21.3	1.0	7.6	0.4
Peaksaver®	0.0	14.4	0.6 **	5.4**
Summer Savings	87.3	48.5	25.2	14.0
Affordable Housing – Pilot	4.6	0.3	0.0	0.0
Social Housing – Pilot	12.8	1.5	3.9	0.5
Energy Efficiency Assistance for Houses – Pilot	2.5	0.5	1.0	0.2
Electricity Retrofit Incentive Program	5.4	1.9	0.1	0.1
Demand Response 1	0.0	342.2	0.0	42.7
Other Demand Response	0.0	28.5	0.0	3.5
Renewable Energy Standard Offer	9.3	2.1	6.6	1.3
Total	**332.7**	**469.4**	**104.7**	**77.3**

Source: OPA Progress Report on Electricity Conservation 2007 and OPA 2007 Final Conservation Results.
Note: * The results from Every Kilowatt Counts were already included in the CDM Annual report shown in Table B3. The additional energy and peak savings not yet reported in the CDM Annual report are about 60.9 GWh and 75.6 MW respectively.

** The energy savings for Peaksaver® program included savings attributed to programmable thermostat offered to Hydro One retail customers.

In 2008, the OPA funded the following CDM programs:

- Mass markets – Every Kilowatt Counts Power Savings Event, Peaksaver®, The Great Refrigerator Roundup, Summer Sweepstakes, Hot and Cool Savings Rebate, Power Savings Blitz, Aboriginal Pilot program, Local Distribution Company Custom Programs
- Business markets – Electricity Retrofit Incentive Program, High Performance New Construction, Toronto Comprehensive Program
- Demand Response Programs

Although final results are not yet available, preliminary results indicate that OPA-coordinated CDM programs in 2008 resulted in an annual savings of approximately 49 GWh for Hydro One retail customers. Table C4 shows the energy and peak impacts of OPA-coordinated conservation programs in 2008 for Hydro One Distribution retail customers.

Table C4: OPA-Initiated Program Results in 2008

OPA Program	GWh Savings for Hydro One Retail Customers	MW Savings for Hydro One Retail Customers
Great Refrigerator Roundup	12.3	1.4
Peaksaver®	1.2	6.4
Summer Sweepstakes	1.9	0.0
Every Kilowatt Counts	14.8	2.0
Cool Savings Rebate	5.5	8.3
Electricity Retrofit Incentive	13.3	2.9
Double Return	0.0	7.4
Total	**49.0**	**28.5**

Source: Estimates prepared by Hydro One Distribution using latest information from OPA as of September, 2009.

Appendix D: Summary of CDM Program Results Initiated by Federal and Provincial Governments and Other Organizations

This appendix summarizes the program results initiated by federal and provincial governments and other organizations for Hydro One retail customers since 2005. Tables D1 to D3 provide the estimated CDM impacts between 2005 and 2007 for Hydro One retail customers using Hydro One Retail's share of the provincial energy consumption by customer class and program. At the time this report is prepared, the federal and provincial government program results for 2008 are not yet finalized. Based on recent trends of these programs, we assume energy savings of 60 GWh in 2008 for Hydro One retail customers. The programs presented in Table D4 are based on best available information as of September, 2009.

Table D1: CDM Program Results by Federal and Provincial Governments in 2005

Federal / Provincial	*Federal and Provincial Programs*	*Total Energy Saved (GWh)*	*Total Summer Peak Saved (MW)*	*Hydro One Share (GWh)*	*Hydro One Share (MW)*
Federal	Existing Buildings Initiative	116.4	29.1	14.8	3.7
Federal	FCM-Green Municipal Funds	0.0	20.4	0.0	2.6
Federal	CIPEC-Dollars to $ense	73.2	12.7	9.3	1.6
Federal	Energy Star Labelling	51.7	8.9	9.6	1.5
Federal	CIPEC-Other Achievements	49.3	7.6	6.3	1.0
Federal	EnerGuide for Existing Homes	11.5	1.3	3.5	0.4
Federal	R-2000	0.5	0.1	0.1	0.0
Federal	EnerGuide for New Homes	0.3	0.0	0.1	0.0
Federal	CIPEC-Industrial Energy Audit Incentive	132.5	0.0	16.9	0.0
Federal	Commercial Building Incentive Program (CBIP)	16.2	0.0	2.1	0.0
Federal	ecoENERGY for Industry-Dollars to $ense	0.0	4.0	0.0	0.5
Federal	Industrial Building Incentive Program (IBIP)	0.1	0.0	0.0	0.0
Non-Profit	Non-profit Total*	6.8	5.0	1.7	1.4
Total		**458.6**	**89.2**	**64.4**	**12.7**

Source: Summary of Electricity Conservation Program & Initiatives in Ontario from 2005-2007, Excluding OPA Funded Programs and Ontario Government Buildings (Ref ID#: 28028), Marbek Resource Consultants, June 2008
Note: * Details of non-profit organizations are shown in Appendix E, Table E1.

Table D2: CDM Program Results by Federal and Provincial Governments in 2006

Federal / Provincial	*Federal and Provincial Programs*	*Total Energy Saved (GWh)*	*Total Summer Peak Saved (MW)*	*Hydro One Share (GWh)*	*Hydro One Share (MW)*
Federal	Existing Buildings Initiative	51.7	12.9	6.6	1.6
Federal	FCM-Green Municipal Funds	55.2	15.6	7.0	2.0
Federal	CIPEC-Dollars to $ense	73.2	12.7	9.3	1.6
Federal	Energy Star Labelling	51.7	8.9	9.6	1.5
Federal	CIPEC-Other Achievements	49.3	7.6	6.3	1.0
Federal	EnerGuide for Existing Homes	20.4	2.3	6.2	0.7
Federal	EnerGuide for New Homes	1.0	0.1	0.3	0.0
Federal	R-2000	0.4	0.0	0.1	0.0
Federal	CIPEC-Industrial Energy Audit Incentive	101.3	13.8	12.9	1.8
Federal	Commercial Building Incentive Program (CBIP)	27.8	0.0	3.5	0.0
Federal	ecoENERGY for Industry-Dollars to $ense	0.0	6.9	0.0	0.9
Federal	Industrial Building Incentive Program (IBIP)	0.9	0.1	0.1	0.0
Provincial	OME-Net Metering	5.5	0.9	1.1	0.2
Non-Profit	Non-profit Total*	16.9	12.3	4.1	3.5
Total		**455.4**	**94.3**	**67.3**	**14.8**

Source: Summary of Electricity Conservation Program & Initiatives in Ontario from 2005-2007, Excluding OPA Funded Programs and Ontario Government Buildings (Ref ID#: 28028), Marbek Resource Consultants, June 2008

Note: * Details of non-profit organizations are shown in Appendix E, Table E1.

Table D3: Program Results by Federal and Provincial Governments in 2007

Federal / Provincial	*Federal and Provincial Programs*	*Total Energy Saved (GWh)*	*Total Summer Peak Saved (MW)*	*Hydro One Share (GWh)*	*Hydro One Share (MW)*
Federal	Existing Buildings Initiative	94.9	23.7	11.8	3.0
Federal	FCM-Green Municipal Funds	111.0	0.0	13.8	0.0
Federal	ecoENERGY for Equipment	51.7	9.4	11.2	1.7
Federal	ecoENERGY Retrofit-Homes	5.7	0.6	1.7	0.2
Federal	ecoENERGY for Industry-Other CIPEC	49.3	7.6	6.1	0.9
Federal	CIPEC-Industrial Energy Audit Incentive	0.0	27.8	0.0	3.5
Federal	Commercial Building Incentive Program (CBIP)	14.6	12.7	1.8	1.6
Federal	ecoENERGY for Industry-Dollars to $ense	73.2	3.7	9.1	0.5
Federal	ecoENERGY for Buildings and Houses-Housing	2.2	0.2	0.7	0.1
Provincial	Ontario's Refrigerants Regulation	16.6	5.4	2.1	0.7

Provincial	OME-Net Metering	5.5	0.9	1.1	0.2
Non-Profit	Non-profit Total *	8.8	7.0	2.2	2.0
Total		**433.4**	**99.0**	**61.8**	**14.2**

Source: Summary of Electricity Conservation Program & Initiatives in Ontario from 2005-2007, Excluding OPA Funded Programs and Ontario Government Buildings (Ref ID#: 28028), Marbek Resource Consultants, June 2008
Note: Since the CDM forecast prepared by Hydro One Distribution is net of Codes and Standards, the savings from Equipment Performance Standard are not included in this report.
* Details of non-profit organizations are shown in Appendix E, Table E1.

Table D4: CDM Programs Initiated by Federal and Provincial Governments

Federal / Provincial	***Programs***	***Source***
Federal	ecoENERGY for Buildings and Houses	*www.ecoaction.gc.ca/buildings*
Federal	ecoENERGY Retrofit - Homes	*http://www.ecoaction.gc.ca/homes*
Federal	ecoENERGY Retrofit - Small and Medium Organizations	*http://www.ecoaction.gc.ca/retrofit*
Federal	ecoENERGY for Industry	*http://www.ecoaction.gc.ca/industry*
Federal	ecoENERGY for Renewable Heat	*http://www.ecoaction.gc.ca/heat*
Federal	Canadian Textiles Program (CANtex)	*http://strategis.ic.gc.ca/epic/internet/inctp-ptc.nsf/en/Home*
Federal	Dollars to $ense Energy Management Workshops	*http://www.oee.nrcan.gc.ca/industrial/training-awareness*
Federal	RET Screen International Clean Energy	*http://www.retscreen.net/ang/home.php*
Federal	Federal Buildings Initiative	*http://oee.nrcan.gc.ca/communities-government/buildings/federal/federal-buildings-initiative.cfm*
Federal	EnerGuide Rating Service	*http://oee.nrcan.gc.ca/residential/personal/new-homes/upgrade-packages/energuide-service.cfm?attr=4*
Federal	R-2000 Standard	*http://oee.nrcan.gc.ca/residential/personal/new-homes/r-2000/standard/current/purpose.cfm?attr=4*
Provincial	Ontario Solar Thermal Heating Incentive (OSTHI)	*http://www.mei.gov.on.ca/english/energy/conservation/?page=OSTHI*
Provincial	Home Energy Savings Program (HESP)	*http://www.mei.gov.on.ca/english/energy/conservation/?page=home-energy-savings-program*
Provincial	Retail Sales Tax (RST) Exemption on Renewable Energy Systems	*http://www.rev.gov.on.ca/english/taxtips/rst/pdf/04.pdf*
Provincial	Retails Sales Tax (RST) Exemption on ENERGY STAR® products	*http://www.rev.gov.on.ca/english/taxtips/rst/pdf/04.pdf*
Provincial	Northern Ontario Heritage Fund: Northern Energy Program	*http://www.mndm.gov.on.ca/nohfc/program_nep_e.asp*
Provincial	Green Light On a Better Environment (GLOBE)	*http://www.globeservices.ca/?page=1*
Provincial	Community Conservation Initiative Fund	*http://www.mei.gov.on.ca/english/energy/conservation/?page=cci*
Provincial	Municipal Eco Challenge Fund (Discontinued)	*http://www.mei.gov.on.ca/english/energy/conservation/?page=MECF*

Provincial	Smart Metering Policy	*http://www.mei.gov.on.ca.wsd6.korax.net/english/energy/electricity/?page=smart-meters*
Other	Doors Closed Campaign (Conservation Council of Ontario)	*http://weconserve.ca/doorsclosed/?page_id=3*
Other	Greeening Sacred Spaces (Faith and the Common Good)	*http://www.faith-commongood.net/gss/index.asp*
Other	Flick Off	*http://www.flickoff.org/home*
Other	Green Roofs for Healthy Cities	*http://www.greenroofs.org/*
Other	Ontario Eco Schools	*http://ontarioecoschools.org/*
Other	Reduce the Juice	*http://www.reducethejuice.ca/*

Source: OPA Ontario's Chief Energy Conservation Officer 2008 Annual Report.
Conservation Bureau website: http://www.conservationbureau.on.ca/

Appendix E: Other CDM Programs and Educational Initiatives in Ontario

This appendix presents a sample of CDM programs and educational initiatives offered by other organizations which will have an impact on Hydro One retail customers. Table E1 below summarizes the CDM programs initiated by non-profit organizations between 2005 and 2007. Energy and peak impacts from these programs for Hydro One Distribution retail are presented in Appendix D, Table D1 - D3. Table E2 provides more detailed information for other CDM programs and educational initiatives.

Table E1: Non-Profit Organizations Initiated CDM Programs 2005-2007

Program Name	***Institution***
Eneract Smart Living Programs	Eneract
Green Tbiz	Toronto Association of Business Improvement Areas (TABIA)
Keep Cool	Clean Air Foundation
Cool Shops	Clean Air Foundation
Go Solar	Clean Air Foundation
Northern Energy Program	Northern Ontario Heritage Funds Corp. (NOHFC)
FLICK OFF Campaign	Flick Off organization
Wattwize	Citizens' Environment Watch
Green Sacred Places	Faith and Common Good
EnerGuide for Houses / ecoENERGY Program	Green Communities Canada
EcoSchools	Ontario EcoSchools
Green Roofs for Healthy Cities	North America Inc.

Source: Summary of Electricity Conservation Program & Initiatives in Ontario from 2005-2007, Excluding OPA Funded Programs and Ontario Government Buildings (Ref ID#: 28028), Marbek Resource Consultants, June 2008

Table E2: Selected 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
Energy Efficient Premium Refund	Canada Mortgage and Housing Corporation (CMHC)

Source: Conservation Bureau Website, www.conservationbureau.on.ca

Appendix F: CDM Education and Communication Programs

This appendix 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

Compared to 2005, Hydro One in 2006 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 more than 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

Table F4 presents all energy conservation related bill inserts sent out to customers in 2008 by Hydro One.

Table F4: Distribution of Bill Inserts and Energy Saving Tips in 2008

Topic	Printed and distributed pieces (000s)
Staying Connected - Spring '08	1,215
Staying Connected - Fall '08	1,215
Summer Sweepstakes cover letter	80
Summer Sweepstakes program	1,001
OPA Great Refrigerator Roundup	1,650
PowerSaverPlus for Residential & Business Customers	1,650
PeakSaver program	1,100
Electricity Retrofit Incentive Program - ERIP	93
PowerSavings Blitz	15
Double Return	2
Conserving Energy Together	5
Total	**8,026**

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. They 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 Undertaken by Customers

This appendix summarizes the results of two studies undertaken by Hydro One Distribution to measure the conservation actions of customers. The first study is an econometric analysis to measure the net impact of CDM programs on energy consumption for 2004-2008 using the hourly load profile approach. This is the same methodology used in Hydro One's Transmission 2009-2010 rate application (EB-2008-0272). The second study is an analysis to measure conservation actions using customer billing data. This is the same methodology used in Hydro One Distribution's 2008 rate application (EB-2007-0681).

Load Profile Analysis

Hydro One undertook a study to measure the load impact of CDM programs for Hydro One retail customers using the hourly load profile analysis approach. This methodology captures the CDM impact by comparing the normalized hourly load profiles for 2004-2008 using actual hourly data for Hydro One retail customers. In this analysis, 2004 represents the base year without CDM programs and 2008 represents latest year with CDM programs. The difference of the load profiles between these four years provides a measure of the net CDM impact achieved to date. CDM impact 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 the OPA, federal and provincial governments.
3. Conservation actions initiated by customers on their own that are not captured and reported in (1) and (2).

Hydro One Distribution undertook this analysis to measure the CDM impact associated with conservation actions undertaken by its customers. Two regressions methods were examined in this study.

The first method is an in-house econometric model built to analyse the hourly loads for 2004-2008. The functional form of load shape analysis for each hour i (i=1, 2, 3….24) is defined as:

Actual Load in hour i = f {CDD, HDD, Day type} where CDD represents cooling degree days and HDD represents heating degree days

Regression equations were used to generate weather normalized hourly load profiles for 2004-2008. **"**Weather adjustment", the difference between the predicted load using normal weather conditions and actual load, was added to the actual hourly load to produce a "normalized" hourly load shape. Thirty-one years of weather data were used to set the typical weather conditions. The economic growth between 2004 and 2008 was removed using the historical relationship between the economic activities (i.e. GDP) and the load. The estimated CDM impact is the difference between the load for 2004-2008 after removing economic growth.

The second method is similar to the first method discussed above in terms of the functional form, actual hourly data for Hydro One retail customers, weather data and removal of economic growth. The only difference is the use of hourly forecasting software program, MetrixND, developed by Itron to generate the weather normalized hourly load profiles.

The regression results for both load profile models are statistically significant. The load profile results from the two models (see Table G1) show that Hydro One retail customers have achieved energy savings in the range of 810 GWh to 995 GWh between 2004 and 2008. Based on this analysis, after adjusting for savings due to CDM programs initiated

from Hydro One Distribution and other agencies as presented in Table 1, CDM impacts attributed to conservation actions initiated by customers on their own are estimated to range from 170 GWh to 355 GWh for 2004-2008. Please note that these savings are above and beyond the natural conservation efforts assumed in the load forecast. These conservation actions are difficult to measure because they are not program specific and therefore the savings are not easily traceable and measureable.

Table G1: Results of CDM Impact Using Econometric Analysis

	In-House Econometric Model	**MetrixND Model**
Total CDM impact (2004-2008)	810 GWh	995 GWh
Minus Identified conservation program savings (2004-2008) from Table 1	640 GWh	640 GWh
CDM impact due to customer own conservation actions	170 GWh	355 GWh

Customer Billing Data Analysis

Hydro One Distribution undertook an analysis to measure the energy savings associated with conservation actions using actual monthly customer billing data. The methodology used by Hydro One Distribution for this analysis is summarized below:

1. A database was created for 2004-2008 for customers who had billing information (and associated meter readings) covering the entire period. New customers or customers cancelling their service during this period were excluded. As a result, a database was created with about 381,000 residential and 76,000 general service customers.
2. 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-2005-0378).

Table G2: Residential and Farm Consumption 2004 - 2008

Customer Class	Customer Count	2004 (GWh)	2005 (GWh)	2006 (GWh)	2007 (GWh)	2008 (GWh)
Farm	37,378	912	895	861	847	830
Residential - High Density	119,228	1,626	1,619	1,567	1,543	1,538
Residential - Low Density	121,300	1,909	1,880	1,830	1,798	1,805
Residential - Acquired	69,210	783	792	773	759	745
Urban	34,281	382	395	382	379	370
Total	381,397	5,612	5,580	5,414	5,326	5,287
% change for all residential customers			**-0.57%**	**-2.98%**	**-1.63%**	**-0.72%**
% change during 2004 and 2008						**-5.9%**

Note: All figures are weather-normal. Only customers with complete monthly billing data for all five years are used in the analysis.

Table G3: General Service Consumption 2004 - 2008

Customer Class	Customer Count	2004 (GWh)	2005 (GWh)	2006 (GWh)	2007 (GWh)	2008 (GWh)
Farm - Phase 1	6,774	227	230	221	218	212
Farm - Phase 3	702	149	153	151	146	143
Small General Service	41,156	902	909	880	877	884
Large General Service	10,098	1,806	1,862	1,816	1,789	1,754
General Service - Acquired	13,399	1,184	1,212	1,183	1,162	1,136
Urban	4,130	465	482	477	469	469
Total	76,259	4,733	4,849	4,729	4,661	4,598
% change for all General Service customers			**2.40%**	**-2.50%**	**-1.40%**	**-1.40%**
% change during 2004 and 2008						**-2.80%**

Note: All figures are weather-normal. Only customers with complete monthly billing data for all five years are used in the analysis.

Table G4: MUSH sector Consumption 2004 - 2008

	Customer Count	2004 (GWh)	2005 (GWh)	2006 (GWh)	2007 (GWh)	2008 (GWh)
Total	3,704	658	659	642	641	639
% change for all MUSH customers			**0.16%**	**-2.56%**	**-0.15%**	**-0.40%**
% change during 2004 and 2008						**-2.95%**

Note: All figures are weather-normal. Only customers with complete monthly billing data for all five years are used in the analysis.

Table G2 shows the weather-normalized consumption for over 381,000 residential customers with good monthly billing data for 2004-2008 by customer rate class. A decline of 5.9% in energy consumption was observed for the residential customers during this period. Table G3 presents the weather-normalized consumption for general service customers with good monthly billing data over the same period. Table G4 shows the same analysis for the MUSH customers (Municipalities, Universities, Schools and Hospitals). During this period, energy savings of 2.8% and 3.0% are observed for the general service and MUSH customers respectively. It is noteworthy that the decline in load (i.e. energy savings) started to become noticeable in 2006 for all customer rate classes and 2006 is the year where increased CDM efforts were launched across the province. The decline in load starting in 2006 can be attributed to a number of factors, including the CDM program impacts initiated by Hydro One Distribution, the OPA, other government agencies as well as customer conservation actions on their own. This finding is consistent with the econometric analysis as well as the CDM survey results presented in Appendix H.

Appendix H: Summary Result of Hydro One 2009 CDM Survey

This appendix summarizes the key results of a CDM survey initiated by Hydro One Distribution in June 2009. A similar CDM survey was completed in 2007, for which over 1,740 customers responded (39.2% response rate). The main objective of the 2009 CDM survey was to assess the conservation actions undertaken by Hydro One Retail customer in 2008 and 2009 that are not easily captured by CDM program results reported by Hydro One Distribution, the OPA and the federal and provincial government agencies. The questionnaire used for the 2009 survey is presented in Appendix J.

The 2009 CDM survey results have clearly demonstrated that Ontario residential customers have continued to participate in the conservation challenge and have taken various conservation actions on their own to save electricity.

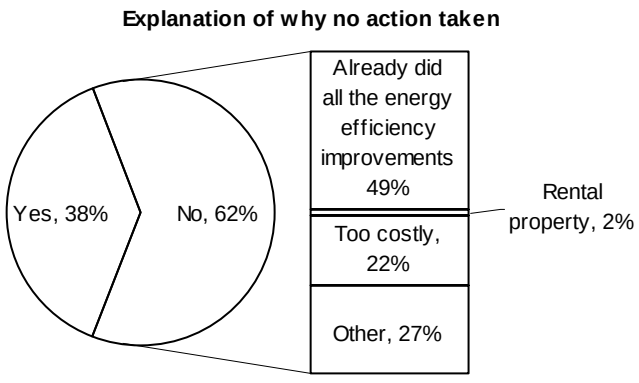
Survey Response Rate:

- Total number of survey requests sent out: 9,450
- Total number of responses received: 2,829
- Overall response rate: 29.9%

Participation in Conservation programs in 2008 or 2009

- In Question 1, 38% of the survey respondents said they participated in CDM programs in 2008 or 2009.
- For those who did not participate in any CDM programs in the last 2 years, about half of the respondents said they have already done all the energy efficiency improvements already.

Have you participated in any CDM programs in 2008 or 2009?	Percentage
Yes	38%
No	62%



- Survey results show about 25% of Hydro One customers plan to undertake conservation actions in the next two years.

Type of Conservation Action	Customers answered "No" in Question 1		Customers answered "Yes" in Question 1	
	Percent of customers who plan to do CDM	How much $ they plan to spend per home	Percent of customers who plan to do CDM	How much $ they plan to spend per home
Increased Home Insulation	23.4%	$1,970	26.6%	$1,881
Upgraded Windows / Skylights / Doors	29.2%	$3,453	32.2%	$3,862
Upgraded Heating System	14.7%	$7,103	12.5%	$5,059
Installed ENERGY STAR® Central AC	7.0%	$2,950	7.2%	$3,224
Installed ENERGY STAR® Window AC	3.6%	$343	1.5%	$342
Installed Energy Efficient Light Bulbs	57.7%	$93	53.2%	$73
Purchased ENERGY STAR® Appliances	28.1%	$1,940	27.6%	$1,459
Installed Programmable Thermostat	18.0%	$111	11.4%	$119
Others	15.5%	$5,028	15.3%	$4,447

Spill-over effects

Survey results show a significant number of customers who undertook CDM actions without receiving incentives. This finding confirms that Hydro One Distribution retail customers are taking CDM actions on their own and these actions are not yet captured in CDM program results reported by Hydro One Distribution, the OPA or other programs initiated by the federal and provincial governments.

Conservation Actions	Number of customers in total	Number of customers who received incentives	Ratio for customers who did not receive incentives versus customers who received incentives
Increased Home Insulation	156	25	5.24
Upgraded Windows / Skylights / Doors	249	29	7.59
Upgraded Heating System	164	73	1.25
Installed ENERGY STAR® Central AC	49	20	1.45
Installed ENERGY STAR® Window AC	36	3	11.00
Installed Energy Efficient Light Bulbs	616	133	3.63
Purchased ENERGY STAR® Appliances	356	80	3.45
Installed Programmable Thermostat	200	64	2.13
Others	88	26	2.38

Conservation Culture

The 2009 survey results are consistent with the 2007 survey results with respect to conservation culture. Both survey results show that Hydro One Distribution retail customers are increasingly taking conservation actions on their own, such as turning off lights when not required, using natural cooling (i.e. not using air conditioning), setting thermostat lower during the day, the night and when away, and using cold water for laundry.

These conservation actions save energy, but they are not easily measureable and the saving impacts are not properly captured.

Conservation Action	2003	2004	2005	2006	2007	2008*	2009*
Use a programmable thermostat	38%	42%	47%	53%	57%	63%	69%
Set thermostat lower during the day and when away	65%	71%	75%	80%	82%	93%	93%
Set thermostat lower during the night	63%	69%	72%	77%	80%	91%	91%
Turn off air conditioner when not at home	39%	43%	48%	53%	56%	63%	70%
Natural cooling	68%	73%	77%	82%	85%	95%	95%
Regular maintenance of air conditioning	55%	59%	63%	67%	69%	63%	71%
Switch to non-electric space heating equipment	22%	25%	27%	29%	30%	38%	41%
Insulate electric water heater and pipes	34%	37%	40%	43%	46%	47%	52%
Use cold water doing laundry	49%	54%	62%	70%	75%	80%	91%
Switch to non-electric water heating equipment	22%	24%	25%	25%	26%	38%	41%
Turn off lights when not required	85%	90%	91%	95%	96%	96%	96%
Use timer for indoor lights	25%	27%	29%	30%	31%	37%	41%
Use timer for outdoor lights	36%	39%	43%	45%	48%	48%	53%
Use a dimmer switch	45%	48%	51%	53%	55%	64%	69%
Use motion sensor	36%	39%	43%	45%	46%	50%	55%
Switch to LED holiday lights	8%	12%	23%	45%	56%	70%	78%
Switch to other LED lights	4%	3%	6%	11%	14%	35%	41%
Use timer on pool pump or heater	7%	8%	9%	10%	11%	11%	12%
Use insulating or solar blanket to keep the pool water warm	11%	12%	13%	14%	15%	13%	14%
Switch to non-electric pool heating	-	-	-	-	-	4%	5%
Hang clothes to dry	54%	57%	61%	63%	65%	74%	83%
Wash dishes by hand	46%	48%	51%	53%	55%	56%	63%
Air sealing and weatherization	37%	41%	47%	52%	54%	64%	71%
Control other equipment with timers	11%	11%	12%	13%	15%	24%	27%

Note: *2008 and 2009 data are based on results from the 2009 CDM survey; the rest are based on results from the 2007 CDM survey.

The following table highlights the conservation efforts our retail customers have achieved over the last few years. The survey results clearly show 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 federal government agencies and have taken various conservation efforts on their own to save electricity. This finding further supports the saving impacts identified in the net load impact analysis using the econometric models and customer billing analysis as presented in Appendix G in this report.

Conservation Action	2003	2004	2005	2006	2007	2008	2009
Set thermostat lower during the day and when away	65%	71%	75%	80%	82%	93%	93%
Set thermostat lower during the night	63%	69%	72%	77%	80%	91%	91%
Natural cooling	68%	73%	77%	82%	85%	95%	95%
Turn off lights when not required	85%	90%	91%	95%	96%	96%	96%

Appendix I: Questionnaire Used in 2009 CDM Survey

Hydro One Account Number: _____ Postal Code: _____

Hydro One Customer Conservation Survey

1. Have you participated in any electricity conservation programs in 2008 or 2009?

   Examples of conservation programs include:
   - Provincial sales tax rebate on new energy efficient appliances/equipments;
   - Hydro One programs (the Great Refrigerator Roundup program, Peaksaver® program, etc.)
   - Grant or loan from government for energy efficiency improvements;
   - Rebate (coupon or mail in) for purchasing an energy efficient appliance/product.

   □Yes □No

2. **(If "No" in Q1)** In the previous question, you answered "No". Please provide an explanation:

   □ Already did all the energy efficiency improvements
   □ Too costly
   □ Rental property
   □ Other (Please provide detail _____)

   Do you plan to undertake any of the following actions over the next 2 years?

	Yes/No	How much do you plan to spend?	Describe action(s) you plan to take
Increase Home Insulation			
Upgrade Windows / Skylights / Doors			
Upgrade Heating System			
Install ENERGY STAR® Central Air Conditioner			
Install ENERGY STAR® Window AC			
Install Energy Efficient Light Bulbs			

Purchase ENERGY STAR® Appliances			
Install Programmable Thermostat			
Others			

(If "Yes" in Q1) In the previous question, you answered "Yes". Please provide details of the actions you have undertaken.

	Year action was taken			How much did you spend in total?	If you received an incentive, how much did you receive?	Describe action taken in more detail
	2008	2009	No Action Taken			
Increased Home Insulation						
Upgraded Windows / Skylights / Doors						
Upgraded Heating System						
Installed ENERGY STAR® Central AC						
Installed ENERGY STAR® Window AC						
Installed Energy Efficient Light Bulbs						
Purchased ENERGY STAR® Appliances						
Installed Programmable Thermostat						
Others						

Do you plan to undertake any further actions over the next 2 years?

	Yes/No	How much do you plan to spend?	Describe action(s) you plan to take
Increase Home Insulation			
Upgrade Windows / Skylights / Doors			
Upgrade Heating System			
Install ENERGY STAR® Central Air Conditioner			
Install ENERGY STAR® Window Air Conditioner			
Install Energy Efficient Light Bulbs			
Purchase ENERGY STAR® Appliances			
Install Programmable Thermostat			
Others			

3. Please identify all conservation actions you have undertaken that are **NOT** specifically related any program initiatives indentified in the previous question and please indicate the year you implemented it.

	Prior to 2008	2008	2009
Heating and Cooling			
Use a programmable thermostat			
Set your home thermostat lower during the day and when away			
Set your home thermostat lower 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 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 (e.g. natural gas)			
Lighting			
Turn off lights when not required			
Use timer for indoor lights			
Use timer for outdoor lights			
Use a dimmer switch			
Use motion sensor			
Switch to LED holiday lights			
Switch to other LED lights			
Pool			
Use timer on pool pump or heater			
Use insulating or solar blanket to keep the pool water warm			
Switch from electric to non-electric pool heating (e.g. natural gas)			
Other actions			
Hang clothes to dry			
Wash dishes by hand			
Air sealing and weatherization			
Control other equipment with timers			

4. What was your TOTAL household income before tax in 2008?
   - □ Less than $20,000
   - □ $20,000 - $39,999
   - □ $40,000 - $59,999
   - □ Over $60,000

5. Please indicate the number of person(s) living in your household in 2008.
   - □ 1
   - □ 2
   - □ 3
   - □ 4
   - □ More than 4

6. Please indicate how many light bulbs in your home those are NOT energy efficient.
   □ Less than 5 bulbs □ 5-10 bulbs
   □ 11-20 bulbs □ More than 20 bulbs

7. Please provide suggestions for conservation programs that would benefit you :
   _____

8. Your feedback is very important to us. Would you like to continue participating in future web surveys about our services, programs and communications?
   □ Yes □ No

Appendix J: Net Load Impact Analysis for Embedded Customers

This appendix summarizes the net load impact analysis for the embedded LDC customers for 2005-2008. The approach used here is similar to the methodology used for Hydro One Distribution retail customers as discussed in this report. Similar analysis could not be undertaken for the embedded direct customers due to lack of information. The CDM impact discussed in this appendix therefore should be considered as conservative because the CDM impact attributed to embedded direct customers are not 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)
- Conservation programs launched by other organizations such as the OPA (Table J3, J4 and J5) and the federal and provincial governments (Table J6, J7, J8)
- Conservation actions initiated by customers of the embedded LDCs that have not been captured elsewhere (Table J9).

Table J1: CDM Impact for Embedded LDC Customers (GWh)

Year	LDC Programs (1)	OPA Programs (2)	Federal and Provincial Government Programs (3)	Annual Program Savings (1-3)	Cumulative Program Savings (1-3)	Additional Impact from Customer Conservation Actions
2005	19	n/a	39	58	58	At least 150
2006	57	3	36	95	153	
2007	39	21	39	99	252	
2008	2	23	39	64	315	
Total	**116**	**47**	**152**	**315**		**150**

Note: N/A denotes not available. CDM impacts are shown at the wholesale purchase level.

Table J1 summarized the analysis presented in Table J2 to J9. Results show that at least 315 GWh of energy savings were identified for embedded LDC customers between 2005 and 2008.

Table J2: Program Results Initiated by Embedded LDCs for 2005-2008

Year	Total peak demand saved (MW)	Total in year kWh saved (GWh)
2005	5.8	19.1
2006	21.8	56.7
2007	11.9	38.6
2008	2.8	1.6
Total	**42.3**	**116.0**

Note: Please note that OPA allocated 2006 and 2007 program savings to LDCs in July 2009, the incremental savings from Every Kilowatt Counts have been included in this table.
Source: 1. Conservation and Demand Management Plan Annual Reports, Appendix C to December 31, 2005, RP-2004-0203 filed March 31st, 2006.
2. Conservation and Demand Management Plan Annual Reports, Appendix C to December 31, 2006, RP-2004-0203 filed April 2nd, 2007.
3. Conservation and Demand Management Plan Annual Reports, Appendix C to December 31, 2007, RP-2004-0203 filed March 31st, 2008.
4. Conservation and Demand Management Plan Annual Reports, Appendix C to December 31, 2008, RP-2004-0203 filed March 31st, 2009.

Table J3: OPA-Initiated CDM Program Results for Embedded LDCs in 2006

OPA Program	Total Provincial Annual GWh savings	Total Provincial Annual MW Savings	GWh Savings Assigned to Embedded LDC Customers	MW Savings Assigned to Embedded LDC Customers
Every Kilowatt Counts *	370.2	4.4	46.0	0.5
Cool Savings Rebate	10.8	11.0	1.3	1.4
Hot Savings Rebate	3.8	3.1	0.5	0.4
Secondary Refrigerator Retirement	5.8	1.3	0.7	0.2
Demand Response 1	0.0	188.2	0.0	14.5
Total	**390.5**	**208.0**	**48.5**	**17.0**

Source: 2006 Conservation Bureau Annual Report.
Note: *The results from Every Kilowatt Counts were already included in the LDC Annual CDM reports shown in Table J2. The additional energy and peak savings not yet reported in the CDM annual report are about 2.5 GWh and 16.4 MW respectively.

Table J4: OPA-Initiated CDM Program Results for Embedded LDCs in 2007

OPA Program	Total Provincial Annual GWh Savings	Total Provincial Annual MW Savings	GWh Savings Assigned to Embedded LDC Customers	MW Savings Assigned to Embedded LDC Customers
Every Kilowatt Counts *	136.5	5.2	16.9	0.6
Great Refrigerator Roundup	14.0	1.6	1.7	0.2
Cool Savings Rebate	31.2	20.5	3.9	2.5
Aboriginal – Pilot	20.5	1.0	2.5	0.1

Peaksaver®	0.0	13.8	0.0	1.7
Summer Savings	83.8	46.5	10.4	5.8
Affordable Housing – Pilot	4.4	0.3	0.4	0.0
Social Housing – Pilot	12.3	1.4	1.1	0.1
Energy Efficiency Assistance for Houses – Pilot	2.4	0.5	0.2	0.0
Electricity Retrofit Incentive Program	5.2	1.9	0.5	0.2
Demand Response 1	0.0	328.2	0.0	29.3
Other Demand Response	0.0	27.3	0.0	2.4
Renewable Energy Standard Offer	8.9	2.0	0.8	0.2
Total	**319.1**	**450.3**	**38.3**	**43.3**

Source: OPA Progress Report on Electricity Conservation 2007 and OPA 2007 Final Conservation Results.
Note: * The results from Every Kilowatt Counts were already included in the LDC Annual CDM reports shown in Table J2. The additional energy and peak savings not yet reported in the CDM annual report are about 21.4 GWh and 42.6 MW respectively.

Table J5: OPA-Initiated CDM Program Results for Embedded LDCs in 2008

OPA Program	GWh Savings for Embedded LDC Customers	MW Savings for Embedded LDC Customers
Great Refrigerator Roundup	4.7	0.5
Peaksaver®	0.5	2.5
Summer Sweepstakes	0.7	0.0
Every Kilowatt Counts Power Savings Event	5.7	0.8
Cool Savings Rebate	2.1	3.2
Electricity Retrofit Incentive	9.2	2.0
Total	**22.9**	**9.0**

Source: Estimates prepared by Hydro One Distribution using best available information from OPA as of September, 2009.

Table J6: Program Savings for Embedded LDCs from Federal and Provincial Governments in 2005

Federal / Provincial	Federal and Provincial Programs	Total Electricity Saved (GWh)	Total Summer Peak Saved (MW)	Embedded LDCs' Share (GWh)	Embedded LDCs' Share (MW)
Federal	Existing Buildings Initiative	111.7	27.9	9.5	2.4
Federal	FCM-Green Municipal Funds	0.0	19.6	0.0	1.7
Federal	CIPEC-Dollars to $ense	70.2	12.1	6.0	1.0
Federal	Energy Star Labelling	49.6	8.6	4.9	0.8
Federal	CIPEC-Other Achievements	47.3	7.3	4.0	0.6
Federal	EnerGuide for Existing Homes	11.1	1.3	1.4	0.2
Federal	R-2000	0.4	0.1	0.1	0.0
Federal	EnerGuide for New Homes	0.3	0.0	0.0	0.0
Federal	CIPEC-Industrial Energy Audit	127.1	0.0	10.8	0.0

	Incentive				
Federal	Commercial Building Incentive Program (CBIP)	15.5	0.0	1.3	0.0
Federal	ecoENERGY for Industry-Dollars to $ense	0.0	3.9	0.0	0.3
Federal	Industrial Building Incentive Program (IBIP)	0.1	0.0	0.0	0.0
Non-Profit	Non-profit Total *	6.5	4.8	0.7	0.6
Total		**439.8**	**85.5**	**38.7**	**7.6**

Source: Summary of Electricity Conservation Program & Initiatives in Ontario from 2005-2007, Excluding OPA Funded Programs and Ontario Government Buildings (Ref ID#: 28028), Marbek Resource Consultants, June 2008
Note: * The details of non-profit organizations are shown on Appendix E, Table E1.

Table J7: Program Savings for Embedded LDCs from Federal and Provincial Governments in 2006

Federal / Provincial	Federal and Provincial Programs	Total Electricity Saved (GWh)	Total Summer Peak Saved (MW)	Embedded LDCs' Share (GWh)	Embedded LDCs' Share (MW)
Federal	Existing Buildings Initiative	49.6	12.4	3.8	1.0
Federal	FCM-Green Municipal Funds	52.9	15.0	4.1	1.2
Federal	CIPEC-Dollars to $ense	70.2	12.1	5.4	0.9
Federal	Energy Star Labelling	49.6	8.6	4.6	0.7
Federal	CIPEC-Other Achievements	47.3	7.3	3.6	0.6
Federal	EnerGuide for Existing Homes	19.6	2.2	2.4	0.3
Federal	EnerGuide for New Homes	1.0	0.1	0.1	0.0
Federal	R-2000	0.4	0.0	0.0	0.0
Federal	CIPEC-Industrial Energy Audit Incentive	97.2	13.2	7.5	1.0
Federal	Commercial Building Incentive Program (CBIP)	26.6	0.0	2.1	0.0
Federal	ecoENERGY for Industry-Dollars to $ense	0.0	6.7	0.0	0.5
Federal	Industrial Building Incentive Program (IBIP)	0.9	0.1	0.1	0.0
Provincial	OME-Net Metering	5.3	0.8	0.5	0.1
Non-Profit	Non-profit Total *	16.2	11.8	1.8	1.4
Total		**436.8**	**90.4**	**36.1**	**7.7**

Source: Summary of Electricity Conservation Program & Initiatives in Ontario from 2005-2007, Excluding OPA Funded Programs and Ontario Government Buildings (Ref ID#: 28028), Marbek Resource Consultants, June 2008
Note: * The details of non-profit organizations are shown on Appendix E, Table E1.

Table J8: Program Savings for Embedded LDCs from Federal and Provincial Governments in 2007

Federal / Provincial	Federal and Provincial Programs	Total Electricity Saved (GWh)	Total Summer Peak Saved (MW)	Embedded LDCs' Share (GWh)	Embedded LDCs' Share (MW)
Federal	Existing Buildings Initiative	91.0	22.7	8.1	2.0
Federal	FCM-Green Municipal Funds	106.5	0.0	9.5	0.0
Federal	ecoENERGY for Equipment	49.6	9.0	5.3	0.9
Federal	ecoENERGY Retrofit-Homes	5.4	0.6	0.7	0.1
Federal	ecoENERGY for Industry-Other CIPEC	47.3	7.3	4.2	0.6
Federal	CIPEC-Industrial Energy Audit Incentive	0.0	26.6	0.0	2.4
Federal	Commercial Building Incentive Program (CBIP)	14.1	12.1	1.3	1.1
Federal	ecoENERGY for Industry-Dollars to $ense	70.2	3.5	6.3	0.3
Federal	ecoENERGY for Buildings and Houses-Housing	2.1	0.2	0.3	0.0
Provincial	Ontario's Refrigerants Regulation	15.9	5.2	1.4	0.5
Provincial	OME-Net Metering	5.3	0.8	0.6	0.1
Non-Profit	Non-profit Total *	8.4	6.8	0.9	0.8
Total		**415.7**	**95.0**	**38.5**	**8.8**

Source: Summary of Electricity Conservation Program & Initiatives in Ontario from 2005-2007, Excluding OPA Funded Programs and Ontario Government Buildings (Ref ID#: 28028), Marbek Resource Consultants, June 2008
Note: Since the CDM forecast is assumed to be net of Codes and Standards, the savings from Equipment Performance Standard are not included in this report.
*The details of non-profit organizations are shown in Appendix E, Table E1.

Program impact for 2008 is not yet available, but is expected to be in the same range as in previous year. Based on historical trends, the energy savings from federal and provincial government programs for embedded LDCs are assumed to be 39 GWh in 2008.

To measure conservation actions initiated by the embedded LDC customers on their own, Hydro One Distribution uses the same load profile analysis methodology as discussed in Appendix G to prepare the econometric analysis for embedded LDCs. The regression results are statistically significant. Table J9 shows that the embedded LDC customers had achieved energy savings in the range of 470 GWh to 745 GWh between 2004 and 2008. Based on this analysis, after adjusting for savings attributed to programs initiated by the

embedded LDCs and other agencies, CDM impact attributed to the embedded LDC customers on their own are estimated to range from 155 GWh to 430 GWh for 2004-2008.

Table J9: Results of CDM Impact for Embedded LDC Customers Using Econometric Analysis

	In-House Econometric Model	MetrixND Model
Total CDM impact (2004-2008)	745 GWh	470 GWh
Minus Identified conservation program savings (2004-2008) from Table 2	315 GWh	315 GWh
CDM impact due to customer own actions from embedded LDCs	430 GWh	155 GWh

Appendix K: OPA Conservation Program Portfolio 2008-2010

This appendix presents the OPA's conservation programs portfolio for 2008-2010. Tables K1 to K3 illustrate the projected CDM savings by program, region, and end-use profile.

Table K1: OPA Portfolio 2008-2010 by Program

Program	Target (MW)	Net Savings (MW)
Mass Market Programs (13 programs)	**451**	**315**
New Single Family Construction Program	45	32
LDC Appliance Retirement Program	120	84
LDC Demand Response Program	108	76
LDC Redesigned Summer Savings Program	3	2
LDC Home Energy Efficiency Program	2	1
LDC Custom Programs	75	53
LDC Small Com. Direct Install Program	9	6
Aboriginal Program	3	2
Cool Savings Program	63	44
Every Kilowatt Counts Program	9	6
Community Engagement Program	6	4
New Appliance Program	8	5
Conservation Awareness	N/A	N/A
Commercial / Institutional Programs (9 programs)	**587**	**410**
Low Income Single Family Program	13	9
New Commercial Buildings Construction Program	30	21
Agricultural Program	3	2
LDC Electricity Retrofit Incentive Program	110	77
Toronto Comprehensive Program	228	159
Multi Family Buildings Program	43	30
Chiller Plant Re-commissioning Program	30	21
Institutional Buildings Portfolio Program	30	21
Fuel Switching Program	100	70
Industrial Programs (5 programs)	**514**	**360**
Industrial Energy Efficiency Program	113	79
Demand Response 1	4	3
Demand Response 2	42	29
Demand Response 3	330	231
Demand Response 4 (2009)	25	18
Other Programs and Costs		
Customer-owned Generation (RESOP and CESOP Programs)	**212**	**148**
Smart Meter Program (Administered by Government)	**176**	**176**
Total	**1940**	**1409**

Source: OPA LDC Web-enabled teleconference, "Conservation Portfolio Overview", Feb. 2008

Table K2: OPA Portfolio 2008-2010 by Region

	System Peak Savings (MW)			Energy Savings (TWh)		
	2008	**2009**	**2010**	**2008**	**2009**	**2010**
Northwest	14	32	64	0	0.1	0.2
West	30	72	161	0.1	0.2	0.7
Northeast	17	42	91	0.1	0.1	0.6
Essa	17	43	96	0.1	0.1	0.5
Ottawa	15	39	97	0.1	0.1	0.6
East	15	37	83	0	0.1	0.4
GTA	80	201	478	0.3	0.7	2.5
Niagara	7	18	41	0	0.1	0.2
Southwest	55	135	296	0.2	0.4	1.3
Ontario	**251**	**620**	**1407**	**0.8**	**2**	**6.9**

Source: Ontario Power Authority IPSP Pre-filed evidence in EB-2007-0707, Exhibit D, Tab 4, Schedule 1, Attachment 4, Table 5.

Table K3: OPA Portfolio 2008-2010 by End Use Profile

	System Peak Savings (MW) in 2010	Energy Savings (TWh) in 2010
Residential	213	1.4
Space Heating SFD	0	0.1
Space Heating AP/AT	0	0.2
Room AC	8	0
Central AC	90	0.1
Furnace Fan	47	0.1
Lighting	35	1
Refrigeration	4	0
Freezer	3	0
Water Heating	5	0.1
Dish Washer	1	0
Clothes Washer / Dryer	4	0
Miscellaneous	16	0.2
Commercial/Institutional	302	1.3
Space Heating	0	0.1
Space Cooling	118	0.1
Ventilation	30	0.2
Lighting	146	0.9
Electric Auxiliary	5	0
Water Heating	3	0
Industrial	107	0.8
Process Machine Drive	45	0.4
Electrochemical Processes	1	0
Steam Production	0	0
Heat Production	38	0.3
HVAC	20	0.1
Lighting	3	0

Source: Ontario Power Authority IPSP Pre-filed evidence in EB-2007-0707, Exhibit D, Tab 4, Schedule 1, Attachment 4, Table 9.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #3
List 1

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Reference: Exh C1/Tab 2/Sch 2/Page 6, Section 2.1.2

a) Please identify separately the amounts planned for spending on PCB testing and retro filling for 2010 and 2011, and actual spending for these activities in 2008.

b) Please provide an estimate of what percentage of the equipment with PCB concentrations of less than 500ppm Hydro One would expect to normally retire by Dec 31, 2025 given that PCBs have not been imported into Canada since 1977.

c) Please indicate the rough project outline, schedule and key milestones within for Hydro One's planned removal of PCBs in stations at concentrations between 50ppm and 500ppm by 2025.

Response

a) Refer to response provided at Exhibit H, Tab 12, Schedule 8.

b) Attrition for Hydro One Distribution's station transformers is approximately 2% to 3% per annum. This results in the replacement of approximately 20 to 30 station transformers each year. Between 2010 and 2025, attrition is expected to result in the retirement of approximately 25% of Hydro One Distribution's fleet of in-service station transformers. These estimates will be further refined based on results from the mandatory testing that will be conducted to meet the 2014 deadline for equipment contaminate at 500 ppm.

c) Hydro One Distribution's current focus is on equipment containing 500 ppm or greater PCBs in order to meet the 2014 extension that has been granted by Environment Canada. The plan includes testing of outstanding equipment prior to 2014 such that all 500 ppm concentrations are identified. The plan is to:

- test an average 110 stations per year between 2010 and 2014
- retrofill equipment that has been found to be in excess of 500 ppm within a reasonable time frame after positive test results but before the 2014 deadline..
- Retrofill equipment that is below 500 ppm by 2025.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #4
List 1

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Reference: Exh C1/Tab 2/Sch 3/Page 8, lines 19 to 21

For the Smart Grid Standard and Technology Program the 2010 and 2011 spending requirements are $ 10 million per year of which $5 million per year is associated with the OM&A spending in the Smart Zone and $5 million per year is to fund a number of studies.

Please provide a detailed list of the studies planned for 2010 & 2011 and include the cost of each study, why the study is necessary, the expected benefits and who will undertake the work (i.e. Hydro One staff or external consultants).

Response

For more details regarding Smart Grid budgeted expenses, please refer to Exhibit H, Tab 9, Schedule 13. The specific studies will be finalized after the response to the planned Request for Proposal (RFP) described at Exhibit H, Tab 12, Schedule 46. The costs, why the study is necessary, the expected benefits and who will undertake the work will all be examined when each study is commissioned.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #5
List 1

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Reference: Exh C1/Tab 2/Sch 5/Page 10, Section 2.1.5

a) Please break out the cost of additional Customer Care Management activities anticipated in 2010 and 2011 for serving new distributed generator customers.

b) Please identify how many additional staff Hydro One plans to add to Customer Care Management to provide service to new distributed generator customers.

c) Please indicate what proportion of the increase in Customer Care Management costs will be outsourced to Inergi.

Response

a) Please refer to Exhibit H, Tab 10, Schedule 34, part c).

b) By the end of 2011, an additional 32 staff are planned for Customer Care Division to handle the increased scope of day to day activities related to servicing renewable distributed generation customers.

c) None of the increases in Customer Care Management is outsourced to Inergi.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #6
List 1

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Reference: Exh C1/Tab 2/Sch 5/Page 4, Table 2

Please provide, as accurately as practical, the cost of meter reading for demand meters from the balance of meter reading activity for the historic, bridge and test years.

Response

Hydro One's financial reporting systems do not track a separate cost for demand meter reading. The meter reading work activity is completed together with readings of all types of meters in the same geographic area.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #7
List 1

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Reference: Ex. C1/Tab 2/Sch 5/Page 5, Section 2.1.1.1

Does this budget proposal include billing changes related to implementation of the harmonized sales tax?

Response

The billing changes related to the proposed implementation of the harmonized sales tax are not included in this budget proposal.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #8
List 1

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Reference: Exh C1/Tab2/Sch2/Section 2.1.2

Please identify separately the amounts planned for spending on PCB testing and retro-filling for 2010 and 2011, and actual spending for these activities in 2008.

Response

The following details Hydro One's planned spend for PCB testing and retro-filling:

	2010 ($M)	**2011 ($M)**
Testing Costs	$2.5M	$3.5M
Retrofilling Costs	$0.2M	$0.2M
Advanced OM&A*	$1.1M	$1.9M
TOTAL	**$3.8M**	**$5.6M**

* Hydro One Distribution plans to leverage opportunities where MUSs have been installed primarily for the purpose of PCB sampling, to advance equipment maintenance coming due within the next one to two years. This will result in reductions of distribution station maintenance expenditures over the longer term as a significant portion of maintenance costs are associated with installing MUSs

With respect to 2008 PCB sampling and retro-filling accomplishments, Hydro One Distribution did not incur any expenditures. As discussed in EB-207-0681, Hydro One Distribution suspended planned expenditures on PCB programs pending new legislation. Given that legislation was only passed in September 2008, it was not feasible to make changes to planned stations programs at such a late stage in the year.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #9
List 1

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Reference: Exh A/Tab 15/Sch 2, Attachment 1

a) Please provide the terms of reference for the benchmarking project conducted by CN Consulting.

b) Please confirm that Figures R8 and R9 both refer to the same type and quantity of work; that is, that Fig R8 refers to the 3 yr average labour hours per tree pruned or removed and that Fig R9 presents labour cost for the same unit of work, averaged over the same period.

c) The text below Fig R12 states, in discussing the higher cost per km for Hydro One unplanned distribution UVM, that "This suggests Hydro One is undertaking greater amounts of unplanned work than the peer utilities and indicates that Hydro One's system can be better controlled". Please provide a chart for this activity equivalent to R9 (p21), indicating labour hours per Km for unplanned 40 UVM.

d) The text below Fig R14 indicates that Hydro One has the longest 1 cycle of any utility in the peer group. However, only 7 of the 14 utilities in the peer group (ref p11) are represented on this chart. Please provide the cycle data for the remaining peer group utilities.

e) The text following R14 indicates that cycle length is contributing to higher unit cost in Hydro One. At the same time, Fig R12 as well as figs R10, R11 and R13 indicate that utility #76 appears to be a significant outlier in terms of higher than average unit cost, yet its cycle length is 4 years according to Fig R14. Without breaching confidentiality, please discuss what other factors besides cycle length may be contributing to much higher than average UVM costs for utility #76.

f) On Figs R8 and R9, utility #45 shows higher than average labour hours and cost per tree treated. On fig R15, utility #45 shows a higher density of treatment per kilometre than all peers except H1 North. On fig R16, utility #45 shows a higher than average removal rate, including higher than the Hydro One average. On fig R13, utility #45 has the second lowest of total UVM costs per system kilometre in the peer group. It would seem to be counter-intuitive that a utility within a similar peer group, that has relatively high unit costs and a high removal rate could have such a low program cost. Please discuss.

g) Please discuss to what extent differences in pay rates may be affecting Hydro One's relatively higher costs per km and per tree.

h) Please provide relative average unit labour costs (e.g., per hr.) for Hydro One and the peer group utilities, or indicate why such is not available.

i) Please indicate which utilities in the peer group contract their UVM program partially or totally to outside contractors.

j) Please provide a chart indicating the total UVM costs per customer for the years 2006-2008, by company.

k) Please confirm that Fig 36 on page 72 refers to the total number of trees on the utility's right of way that require either pruning or removal over the course of a multi-year cycle.

Response

a) Please see Attachment 1.

b) No. Figure R8 does refer to the 3-year average labour hours per tree treated. However, Figure R9 refers to the 3-year average total cost per tree treated and not only the labour cost.

c) The comparison requested is unavailable as the study did not capture this information.

d) Figure 14 contains the cycle lengths reported by participating utilities. The remaining utilities did not report their cycle lengths to the study.

e) Unit costs can be impacted by a variety of factors, some of which are independent of cycle length. This is evident in the case of utility 76, whose costs have been influenced tremendously by organizational and legislative changes. In 2006, new job planning initiatives were launched at the utility such as electronic record keeping and tree inventory capture. These initiatives greatly impacted job planning costs and later continued as part of overheads and other costs. Furthermore, during the 2006 to 2008 period, there was much discussion about benefits of vegetation management within utility 76's jurisdiction. After the discussions, new legislation was enacted in 2008 that provided new powers and responsibilities to utilities in 76's jurisdiction to maintain rights of ways. This combination of organizational change and increased legislative requirements are considered abnormal and resulted in increased unit costs at utility 76.

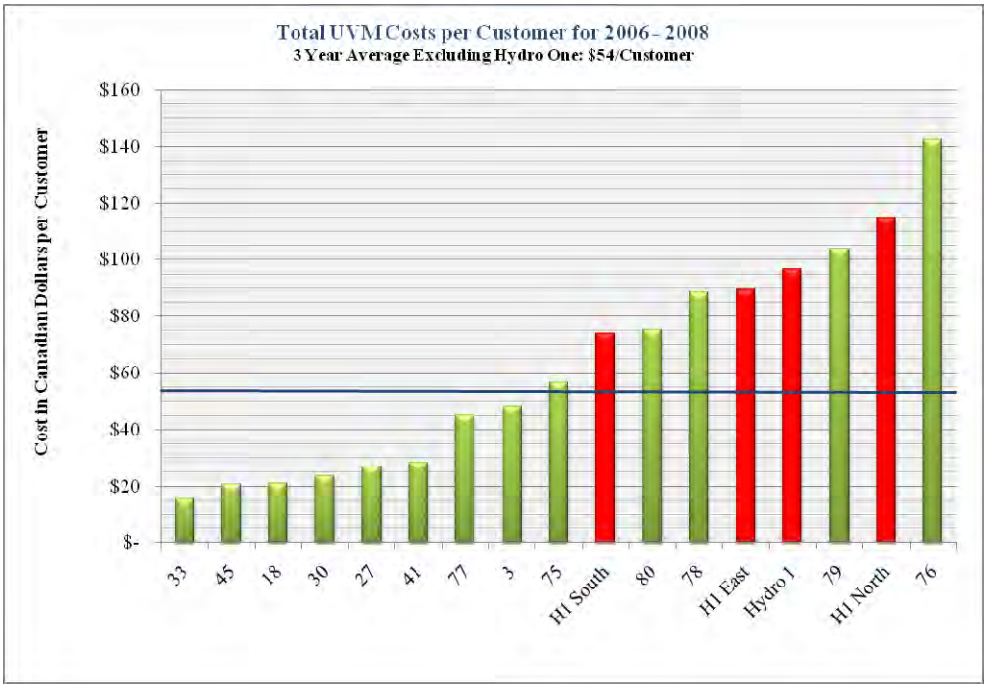
f) The low Total UVM Costs per System Kilometre at utility 45 is attributed to a significant budget cut in 2007 and 2008. In these years, funds were cut by almost half from 2006 levels. This resulted in very low accomplishments.

g) Differences in pay rates will impact unit costs. As the study focused on efficiency and not compensation, the extent of the impact is unknown.

h) The study focused on efficiency and not compensation. As such, labour rate information is not available.

i) CN Utility can confirm that the following utilities contract their UVM program out either partially or fully: 3, 18, 27, 33, 75, 76, 77, 78, 79, 80, 82.

j) Please refer to the chart below.



k) Confirmed.

Request for Proposal – Vegetation Management Benchmarking

Introduction

Hydro One will be submitting a Distribution Rate Application in late June or early July of 2009 to the regulator, the Ontario Energy Board (OEB). As part of the previous (2008) rate decision, the OEB instructed Hydro One to develop a benchmarking approach that will provide definitive information respecting the company's relative efficiency in the area of distribution vegetation management. The specific instructions provided by the Board are as follows:

> "Accordingly, the Board will require the Company, in consultation with the intervenors and Board staff, to develop a benchmarking approach which will provide the Board at the next rebasing exercise with definitive information respecting the Company's relative efficiency in this area of operations."

On Wednesday April 15th, a stakeholder session was held with intervenors and Board staff. Based on feedback received at that session, Hydro One is proposing the following scope of work.

Scope of Work

Hydro One is seeking the services of a vegetation management benchmarking consultant that is an expert in the field to complete the required assignment. The consultant is expected to complete the assignment in the following stages:

1. **Study Plan (May 8th) –** The consultant is to develop plans for the benchmarking study. This stage will include:
    - Defining what constitutes "definitive" information in relation to the OEB's request;
    - An examination of various benchmarking approaches including the consideration of 'statistical benchmarking';
    - A discussion of what information is freely available from public sources (e.g. FERC, OEB, trade organizations);
    - Developing the benchmarking framework that will be used in the study;

2. **Selection of Study Measures (May 15th)** – The consultant will select measures in consultation with Hydro One that will be used to benchmark Hydro One's 'relative efficiency' in vegetation management. The measures selected are to represent the following performance areas:
    - Cost
    - Reliability
    - Safety
    - Operations
    - Productivity

3. **Comparable Company Selection (May 15th)** – The consultant will identify comparable utilities to Hydro One and the subsets of Hydro One's service territory if possible. This will include:
    - Characterizing Hydro One's service territory and subdividing it for comparison purposes;
    - Identifying criteria that are to be used for defining comparability (e.g. customer density, system configuration);
    - Identifying regions of North America that are similar to Ontario in terms of vegetation, geography and weather conditions among others;

4. **Gather Data (June 19th) –** The consultant will contact utilities and obtain benchmarking data for multiple years.

5. **Conduct Analysis (July 10th) –** The consultant will analyze data, conduct the study, and produce draft results.

6. **Final Results & Report (July 31st)** – The consultant will complete the final report outlining findings and providing details on work and program practices.

7. **Defence of Study (To Be Determined) –** The consultant will be expected to defend the study plan, findings and conclusions within a regulatory proceeding. This would include all normal phases of a full hearing including a written interrogatory phase, and other discovery processes defined by the regulator, and a full, formal regulatory hearing, either oral or in writing, before the OEB. This would also include the preparation of other related evidence, as necessary to support the methodology and measures applied along with related assumptions on economic parameters, comparable companies, etc.

Hydro One would like to maximize utility participation in the benchmarking exercise and recognizes that data confidentiality is an important issue. As a result, the identities of the utilities asked to participate in the study should not be associated with any particular data or analysis. The final report will however identify a list of participating utilities and will be submitted as part of Hydro One's Distribution Application to the Ontario Energy Board. This application will be on the public record.

Final Deliverable – Complete a report detailing the benchmarking study, its observations, findings, and conclusions.

Contact Information:

For further details, please contact:

Elias Lyberogiannis, P.Eng., MBA, CMA
Sustainment Manager – Distribution Lines Department
Sustainment Investment Planning Division
Hydro One Networks Inc.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #10
List 1

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Reference: Exh C1/Tab 2/Sch 2/Page 34, Table 10

Please provide brush control and line clearing accomplishment data (km) for the historic and (projected) bridge years.

Response

Please refer to Exhibit H, Tab 1, Schedule 34.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #11
List 1

Interrogatory

Issue 3.2 Is the 2010/2011 vegetation management budget appropriate?

Reference: Exh C1/Tab2/Sch 2/Page 34, lines 23-25

Please provide the Hydro One experience data that supports the statement that begins "Experience has shown,,,"

Response

The experience data is based on the charts and analysis contained on page 6 of the 2008 Vegetation Management Program Review that was filed in EB-2007-0681, Exhibit H, Tab 1, Schedule 14, Attachment B.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #12
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh C1/Tab 2/Sch 7/Page 1, Table 1

The total Common Corporate Functions and Services costs have increased by approximately $11 million in 2009 due mainly to meet expanded work field programs driven by the Green Energy and Green Economy Act (GEGEA) related to distributed generation and smart grid.

Reference: Exh C1/Tab 2/Sch 7/Page 4, lines 14 to 16

Increases in 2010 and 2011 in the Corporate Management Function are mainly due to additional work requirements driven by the GEGEA.

Reference: Exh C1/Tab 2/Sch 7/Page 16, lines 6 to 8

The increase in costs in 2009 and 2010 for General Counsel and Secretariat are driven mainly by increased work programs related to the GEGEA and the records management project expected to begin in 2009 and continue through 2010.

Please identify the specific work programs and related costs including number of additional staff included in the expenditures for corporate management, finance, human resources, corporate communications & services, general counsel and secretariat, regulatory affairs, corporate security and internal audit that are driven by the initiatives of the GEGEA. Please identify the specific GEGEA initiatives that these work programs correspond to.

Response

While Hydro One recognizes that work related to the Green Energy Plan is contributing to an increase in costs as described in the evidence, costs in CCFS have not been broken out between “green plan” vs “non-green plan” spending. The plan reflects a change in the scope of day-to-day work activities.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #13
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh C1/Tab 2/Sch 8, Pages 7 to 10

System investment costs have increased in 2009, 2010 and 2011 in part due to a significantly increased work program resulting from the initiatives of the GEGEA.

Please identify the specific work program activities and include a breakdown of costs for system investment work that correspond directly to initiatives driven by the GEGEA.

Response

The Green Energy Plan as included in Exhibit A, Tab 14, Schedule 2 provides, a high-level overview of the major 'green' programs and initiatives that Hydro One will be undertaking. The exhibit summarizes the program and project investments required because of the Green Energy Act.

In general the System Investment group provides support based on the demand and requirements of the transmission and distribution work programs, including the initiatives of the Green Energy Act.

The work program activities of the System Investment function can be seen at Exhibit C1, Tab 2, Schedule 8, pages 7 to 10.

The breakout of the costs can be seen at Exhibit H, Tab 7, Schedule 61, part b, Table 1.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #14
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh C1/Tab 2/Sch 8/Pages 10 & 11

Work Program Optimization has experienced year over year increases of $0.4 million in both 2010 and 2011 due in part to significant increased work program resulting from the GEGEA.

Please identify the specific work program activities and include a breakdown of costs for work optimization programs that correspond directly to initiatives driven by the GEGEA.

Response

The Green Energy Plan as included in Exhibit A, Tab 14, Schedule 2 provides, a high-level overview of the major 'green' programs and initiatives that Hydro One will be undertaking. The exhibit summarizes the program and project investments required because of the Green Energy Act.

In general the Work Program Optimization group provides support based on the demand and requirements of the growing transmission and distribution work programs, including the initiatives of the Green Energy Act.

The work program activities of the Work Program Optimization group can be seen at Exhibit C1, Tab 2, Schedule 8, pages 10 and 11.

The breakout of the costs can be seen at Exhibit H, Tab 7, Schedule 61, part b, Table 1.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #15
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh C1/Tab 2/Sch 8/Pages 12 to 14

The Business Integration function has experienced a year over year increase of 6% in 2010 and 15% in 2011. The increase is due to Business Integrations overall support for the growing work program including the initiatives of the GEGEA.

Please identify the specific work program activities and include a breakdown of costs for work optimization programs that correspond directly to initiatives driven by the GEGEA.

Response

The Green Energy Plan as included in Exhibit A, Tab 14, Schedule 2 provides, a high-level overview of the major 'green' programs and initiatives that Hydro One will be undertaking. The exhibit summarizes the program and project investments required because of the Green Energy Act.

In general the Business Integration group provides support based on the demand and requirements of the growing transmission and distribution work programs, including the initiatives of the Green Energy Act.

The work program activities of the Business Integration group can be seen at Exhibit C1, Tab 2, Schedule 8, pages 12 to 14.

The breakout of the costs can be seen at Exhibit H, Tab 7, Schedule 61, part b, Table 1.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #16
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh C1/Tab 2/Sch 8/Pages 16 to 19

The Real Estate & Facilities function is proposing year over year OM&A increases in 2010 and 2011 in anticipation of the need for work space accommodation requirements driven by increased workload and staff levels that include the recent initiatives of the GEGEA.

Please identify the specific OM&A expenditures in 2010 and 2011 needed to accommodate the initiatives of the GEGEA.

Response

Please refer Exhibit H, Tab 9, Schedule 24.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #17
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh C1/Tab 2/Sch 9/ Page 18

The Voice Services component of Business Telecom will see increases in 2010 and 2011 that reflect an increase in headcount and new site builds to accommodate increased core SDO work programs, largely due to the GEGEA.

Please provide a breakdown of costs related to the GEGEA to support the proposed increases.

Response

Voice services costs primarily include monthly charges and usage fees for voice grade business telecom (local and long distance). For 2010, there is an increase of $1.0M in voice services due to projected increases in headcount due to the GEGEA. For 2011 there is a further increase of $0.2M in voice services largely due to GEGEA.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #18
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh C1/Tab 2/Sch 9/Page 1, Table 1

The proportion of the corporate OM&A budget for IT that will be consumed by IT management seems to be more than doubling from 2008 to 2010.

a) Please provide any supporting studies that Hydro One has conducted or commissioned to support such a large proportionate increase in IT management.

b) Please indicate what portion of the IT management budget is planned to be spent on consultant and professional services.

Response

a) There were no studies conducted because the increase in IT Management budget was due to internal re-organizational transfers ($12.2M of the $13.7M). Please refer to Exhibit H, Tab 1, Schedule 51. The remaining increase of $1.5M is due to the addition of personnel for business application support of SAP, program management, IT outsourcing management, Business Intelligence/Business Warehouse (BI/BW) support and governance and Smart Grid information systems support and governance.

b) Hydro One IT management budget does not include the use of consultants or professional services in the 2010 budget year. IT intends to manage its head count to remain within budget and will do so using a combination of full time staff or using staff in a contract role until appropriate individuals can be found.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #19
List 1

Interrogatory

3.3 Is the proposed level of 2010/2011 Shared Services and Other O&M spending appropriate?

Reference: Exh A/Tab16/Sch 1/Page 5, Table 1
Reference: Exh C1/Tab2/Sch 9/Table 1

In Exh A/Tab 16/Sch 1/Page 5,Table 1, incremental savings attributable to Cornerstone in 2010 and 2011 appear to total $7.6M, including both capital and OM&A. In Exh C1/Tab2/Sch 9, Table 1, incremental OM&A for IT rises by approx $50M between 2008 and 2010, with slightly over half of the total corporate OM&A allocated to Distribution. On the surface, it would appear that the cost to maintain IT is greater than the benefits being ascribed to its implementation.

Please identify whether or not the productivity improvements identified in Exh A/Tab16/Sch 1 attributable to Cornerstone are net of the cost to maintain and operate the Cornerstone systems.

Response

No. The productivity savings are not net of the cost to maintain Cornerstone.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #20
List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, 1 benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Reference: Exh A/Tab14/Sch 1/ Page 2, lines 18-20

Please provide the details of the COLA trigger that may apply to Society represented staff in 2011.

Response

In 2011, the Society has a COLA clause that triggers if the CPI for Ontario, published in March 2011, is a full 1% above 2.5% (i.e. 3.5%).

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #21
List 1

Interrogatory

Issue 3.6 Is Hydro One's depreciation expense appropriate?

Reference: Exh C2/Tab1/Sch 1

Please complete the following table, for those investments proposed within or justified by the Green Energy Plan.

Asset Category	2010 Investment	2011 Investment	Depreciation Rate
Major Fixed Assets			
Minor Fixed Assets			

Response

All investments proposed within the Green Energy Plan are considered Major Fixed Assets.

Asset Category	2010 Investment	2011 Investment	Depreciation Rate
Major Fixed Assets	$138.6M	$235.9M	5%

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #22
List 1

Interrogatory

Issue 3.9 Is the proposed spending on loss reduction efforts appropriate?

Reference: Exh A/Tab 14/Sch 4/Page 19, Table 4
Reference: Exh G1/Tab 10/Sch 1/Page 2, Table 1

Hydro One's load forecast suggest a decline in total energy demand from 40,609 GWh in 2006 to 38,049 GWh in 2011, a drop of slightly over 6%. Physical law suggests that, all other factors being equal, load related losses vary as the square of the current, which in turn varies directly with energy delivered. On its own, this would suggest slightly over a 12% reduction in load losses during this period. In addition, Hydro One has or will have made considerable incremental investments in distribution assets over the 2006-2011 period, presumably 1 much of it in more efficient equipment such as larger conductor, higher distribution voltages, etc.

Why is Hydro One proposing to leave its calculated loss factors unchanged?

Response

The engineering study done by Kinectrics on behalf of Hydro One to determine losses showed that losses are estimated to be higher than the loss factors approved by the OEB. Please see Exhibit G1. Tab 10, Schedule 1, page 1, lines 11 to 16.

Hydro One is not proposing to change the loss factors to reflect the Kinectrics study.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #23
List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Reference: Exh D1/Tab 3/Sch 2/Page 26, Section 2.3

Hydro One is required (as per the Distribution System Code) to upgrade an existing customer's demand meter to an interval meter when the average monthly peak demand is equal to or greater than 1000 kW.

a) What is the total number of demand meters to be upgraded to interval meters?

b) Please complete the following table.

Description	2006	2007	2008	2009 Bridge	2010 Test	2011 Test
# of Interval Meter Upgrades for customers > 1000 kW						
Program costs (customers > 1000 kW)						
# of Interval Meter Upgrades for customers > 5000 kW						
Program costs (customers > 5000 kW)						

Response

a) The total number of demand meters to be upgraded to interval meters is 10.

b) See table below. Hydro One does not breakout the cost upgrades for customers beyond the 1000 kW threshold (i.e. > 5000 kW category) as the same meter is used for consumption > 5000 kW.

Description	**2006**	**2007**	**2008**	**2009 Bridge**	**2010 Test**	**2011 Test**
# of Interval Meter Upgrades for customers > 1000 kW	0	1	3	0	5	5
Program costs (customers > 1000 kW)	0	$3,800	$11,400	0	$19,000	$19,000
# of Interval Meter Upgrades for customers > 5000 kW	0	0	0	0	0	0
Program costs (customers > 5000 kW)	0	0	0	0	0	0

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #24
List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Reference: Exh D1/Tab 3/Sch 2/Page 26, Section 2.3
Reference: Exh D2/Tab 2/Sch 3/IDS S31

Hydro One is proposing to replace about 7,500 "dumb meters" with electronic demand meters that have communications capability to eliminate manual meter reading. The proposed OM&A investments of $ 1.3 million in 2010 and $1.7 million in 2011 are to replace the first 4,250 meters.

a) What plans does Hydro One have beyond 2011 to replace the balance of the meters and when will the Program be complete?

b) Please complete the following table regarding the Demand Meter Conversion Program.

Description	2010	2011	2012
# of Meter conversions: Customers > 250 kW			
Program costs (customers > 250 kW)			
# of Meter conversions: Customers > 1000 kW			
Program costs (customers > 1000 kW)			
# of Meter Upgrades: Customers > 5000 kW			
Program Costs (Customers > 5000 kW)			

Response

a) The plan is to replace all remaining "dumb meters" by the end of 2012.

b) The level of detail requested in the table is not available because:

- The Demand Meter Conversion Program scope is only for meters >50kW<1000kW. Hydro One Distribution does not have anything in this program above 1000 kW.
- The specific meters in scope are not all identified at this time.

Hydro One can offer the following information with respect to this program:

- The number of meters planned per year is 1,250 in 2010 and 3,000 in 2011. We do not have a specific listing that breaks out the meters by kW demand load because the list has not been finalized at this time.
- The identification of the specific meters that are changed under the program is developed annually to meet the overall plan. The selection criteria includes:

    - cellular coverage availability
    - meter seal expiry date
    - local resource availability
    - smart meter production area and route completion

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #25
List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Reference: Exh D2/Tab2/Sch 3/IDS S31

a) Please explain the difference between the 7,500 demand metered accounts and the proposal to replace only 4,250 legacy demand meters with new electronic meters.

b) Please indicate whether the new electronic demand meters proposed in this project will provide the affected customers with the same opportunities to obtain meter information and manage their consumption that formed the rationale for the residential Smart Meter program.

c) Please provide an estimate of the savings in meter reading and meter management costs that will occur as a result of this project being implemented, by year.

Response

a) The 7500 meters for demand tariff customers will be replaced under the demand meter replacement program. The 4,250 refers to those meters of the program that will be installed in 2010 and 2011.

b) There are no immediate plans to provide the same level of information for these customers because the Meter Data Management / Repository (MDM/R) does not currently support this functionality. Opportunities will become available once this functionality is in-service with the Smart Meter Entity (SME).

c) The meter reading savings from these meters are captured in the meter reading budget shown in Exhibit C1, Tab 2, Schedule 5, page 8. Further we anticipate that these customers will also be converted to time-of-use rates and so will need TOU capable meters. Rather than converting these meters to smart meters under a separate program, we are taking advantage of a Measurement Canada compliance program that requires a meter change which essentially saves the cost of a duplicate trip.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #26
List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Reference: Exh D1/Tab 3/Sch 2/Page 26, Section 2.3
Reference: Exh D2/Tab 2/Sch 3/IDS S30

Hydro One is converting approximately 71,000 legacy meters with 4 jaw bases that are eligible for a Smart Meter replacement, to 5 jaw bases in order to accommodate Smart Meters. The OM&A investment of $1.3 million in 2010 is to retrofit the remaining 24,000 meters with a 4 to 5 jaw adaptor and install a Smart Meter.

a) For each applicable customer class, please quantify the number of adaptor and smart meter installations from the beginning of the Program until Program completion in 2010 and provide the cost of this work for each customer class.

b) Is the cost of the Smart Meter included in the Program costs or are they funded separately under the Smart Meter Program?

Response

a) The chart below provides an estimate of the installation information requested.

Customer Class	2008	2009 Planned	2010 Planned	Total Planned Installs	Costs ($K)
Farm	1,012	22,306	14,030	37,348	$2,024
General Service	55	6,184	3,460	9,699	$526
Residential	588	10,195	5,468	16,251	$881
Seasonal	38	1,682	1,042	2,762	$150
Meters changed; met current standards & did not require adapters				4,940	
Total	**1,693**	**40,367**	**24,000**	**71,000**	

b) No, the cost of the Smart Meter is not included in this program's costs; the Smart Meter is funded separately under the Smart Meter Program.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #27
List 1

Interrogatory

4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Reference: Exh D2/Tab 2/Sch 3/IDS IT5

The proposed Enterprise GIS Program needs to be understood in terms of the full cost commitment that will be required to make it fully effective.

a) Please provide the business case for this project.

b) Does the proposed budget include gathering data that is not already available? If not, what are the expected data acquisition and/or data conversion/data cleanup costs that would be required to deliver the benefits described on the project summary?

c) Has Hydro One selected a vendor for this project?

d) Has Hydro One chosen a particular approach to this project, such as using pre-existing proprietary mapping databases, partnering with Google, etc? If so, please provide the evaluation of alternatives that were considered?

e) The project description identifies increased safety as a benefit if the project is approved and a safety risk if it is not. Please identify where current safety procedures fail to safeguard worker safety when operating or system configuration information is inaccurate or incomplete.

Please confirm that the proposed budget for this project includes all necessary 1 associated activities, such as data collection and data cleanup.

Response

a) The business benefits of the Enterprise GIS Program are further explained in ExhD1/Tab3/Sch6/pp 13-14 and include improvements to outage restoration and distribution system reliability in terms of GIS being the foundational technology for smart grid applications. As such, business benefits go beyond cost savings. In 2008, Hydro One engaged a consultant to produce a strategy and roadmap for the GIS program. On the basis of this independent third party evaluation, costs for the implementation of the Enterprise GIS Program were estimated at $27M with projected savings of $17M. Leveraging this strategy work, Hydro One subsequently developed a program estimated at $20.9M and approximate savings of $1M starting

in 2011 and phasing in to approximately $3M per year thereafter as data consolidation is completed. . Savings are based primarily around improved efficiency through consolidation of redundant spatial data sources and the elimination of redundant work processes, and through optimized logistics for field deployment, including avoided field trips. The proposed budget for 2010 and 2011 is primarily for post-processing field collected data and for consolidating independent spatial databases into a single, consistent system of record.

b) Hydro One has leveraged the provincially mandated requirement to perform asset condition assessment on a six-year cycle to perform field collection, so the proposed budget does not include data gathering. Processing of field collected data to convert it to spatially accurate networked locations and consolidation of this data from the multiple other spatial databases is estimated at $8.5M.

c) Post processing of field-collected data with spatial accuracy is being completed internally using full-time and temporary staff. Current plans are to competitively tender the spatial database consolidation in 2010.

d) There is no commercially available or proprietary alternative to acquiring Hydro One facilities data. Hydro One does leverage provincially available land base data. All of this data will be stored in the existing enterprise GIS.

e) Hydro One follows all current work protection practices. However, maintenance of operating maps is currently a manual process. As the system continues to grow in size and complexity, particularly with the introduction of distributed generation, there is a need to improve efficiency to maintain operating maps in order to maintain adequate work protection barriers. In addition, the deployment of automated vehicle location will provide an enhanced capability to locate crews in the event they are incapacitated and not able to respond, particularly given the remote nature of much of Hydro One's service territory.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #28
List 1

Interrogatory

4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Reference: Exh D1/Tab 3/Sch 9/Page 9, Section 2.0
Exh D2/Tab2/Sch 3/IDS C4

a) Please identify the specific transport and work equipment budget requirement increment attributable to GEGEA-driven activity.

b) Please identify the number of licensed (self powered) vehicles Hydro One will have in service at the end of 2011, if this budget is approved.

c) Please provide a copy of Hydro One's vehicle use policies that set the conditions whereby staff may take vehicles home at night and that identify when staffs are to be assigned specific vehicles for regular use.

Response

a) Please refer to Exhibit H, Tab 7, Schedule 92.

b) Hydro One expects to have approximately 4,700 licensed vehicles in service at the end of 2011, if this budget is approved.

c) A copy of the vehicle use is provided in Attachment 1.

Document Number: **SP 0773 R0**

Document Name: **Corporate Vehicle Policy**

Issue Date: **June 2009**

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The requirements of this document are mandatory.

Purpose

This document describes the policy for assignment of Corporate Vehicles to employees in connection with their travel while on business assignment.

Revision

Information contained in the policy, approved in February 2006, is now contained in this document.

Contents

1.0 Scope

2.0 Policy Statement

3.0 Corporate Requirements

4.0 Exceptions

5.0 Definitions

6.0 References

Appendix A: Document Management

1.0 Scope

This policy applies to the assignment of Corporate Vehicles to employees in connection with their travel while on business assignment. It does not apply to the assignment of Corporate Vehicles as part of employees' overall compensation and benefits.

2.0 Policy Statement

Hydro One Inc. will assign a Corporate Vehicle for an employee's use where a business case shows this will be more economical for the Corporation than other alternatives, such as paying for the use of the employee's own vehicle at the existing Corporate kilometer rate, or short-term rentals.

3.0 Corporate Requirements

1. The decision to assign a Corporate Vehicle to an employee will be based upon a business case approved by Local Line Management comparing the total cost to the Corporation of providing an assigned vehicle with:
    - Total cost to the Corporation of the expected amount of business travel by the employee at the current kilometer rate; and
    - Total costs to the Corporation of other alternatives. (Total costs to include depreciation, maintenance, licensing, repairs, fuel, insurance, and so on, and factoring in residual value of vehicles upon termination of leases).
2. When a business case indicates that assignment of a Corporate Vehicle is **less costly** to the Corporation, there will be no option for employees to use their own vehicles or a vehicle from an external rental agency.
3. Local Line Management must maintain assigned vehicle listings that must be reviewed annually for continuing validity.
4. The type and standard of the Corporate Vehicle being assigned will be the minimal consistent with the expected usage and established standards.
5. The assignment of a Corporate Vehicle will not result in a financial benefit to the employee.
6. Personal use of Corporate Vehicles is to be kept to a minimum, and all reasonable expenses associated with such use, as well as fines for parking and other traffic violations, are to be borne by the employee.
7. Assignment of a Corporate Vehicle to an employee will result in taxable benefit computed in accordance with the Income Tax Act. There will be no allowances provided to employees to fully or partially offset the employee's tax burden associated with the taxable benefit (see References section).
8. Employees with assigned Corporate Vehicles must comply with all Canada Revenue Agency (CRA) requirements for tracking vehicle usage (see References section).
9. Corporate Vehicles will be disposed of in a manner most favourable to the Corporation.
10. Exceptions to this policy must be approved by Direct Reports to the President & CEO.

4.0 Exceptions

Management Compensation Plan (MCP) staff who would otherwise be assigned a corporate vehicle has the following options:

1. Using the Corporate Assigned Vehicle and complying fully with the requirements set out in this policy, including agreeing to withholdings at source that are required by the CRA for any benefits associated with the assigned vehicle (see References section).
2. Using a personal vehicle of the type required for the job, and receiving reimbursement, for business use only, that is up to the total cost to Hydro One of providing a Corporate Assigned Vehicle. The calculation of the business use reimbursement will be as per Fleet Management and be based on the following:

    - Reimbursement at the current kilometer rate up to the break-even mileage for the particular vehicle type, based on total driving costs; and,
    - Reimbursement at a reduced rate covering only operating costs of the vehicle for the balance of the km usage.

5.0 Definitions

Assignment of Vehicles: "Assignment" means providing a specific vehicle for a specific employee's exclusive use, for a period of more than 30 days.

Corporate Vehicle: Any vehicle owned, leased or rented by the Corporation.

Business Use: Any use made of the vehicle for the purpose of conducting the Corporation's business; business use includes travel to any place or facility to transact business or to represent Hydro One. The CRA has established explicit rules covering this use.

Personal Use: Any use, which is not for business purposes. Personal use includes direct travel between the employee's home and normal work location. The CRA has established explicit rules covering this use.

6.0 References

Please refer to the document titled Vehicle Benefits.pdf in Section Miscellaneous Policies and Procedures within web site http://finance.hydroone.com/PolicyProc/

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #29
List 1

Interrogatory

4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Reference: Exh D1/Tab 3/Sch 8/Page 4

The Shared Services Facilities & Real Estate capital program (Head Office & GTA Facilities) shows capital investment of $32 million in 2010 and $32.4 million in 2011 to secure accommodation (including furniture systems) for additional staff resulting from expanded work programs including GEGEA initiatives.

Please identify the number of additional work spaces and furniture systems required and costs to accommodate the initiatives of the GEGEA.

Response

The Company estimates minimum of $5M in 2010 and $4.5M in 2011 in additional investments required to secure leased administrative office space within GTA as result of anticipated increase in work activities mainly due to the Green Energy Act.

The assessment of space needs continues, in cooperation with the respective business units, and will clarify (as better information become available) the requirements associated with the increasing work program, especially the requirements resulting from the implementation of the Green Energy Act, the modernization of distribution systems and connecting distributed generation.

Please also refer to response at Exhibit H, Tab 1, Schedule 105.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #30
List 1

Interrogatory

4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Reference: Exh D2/Tab 2/Sch 3/IDS C3

Project C3 (Shared Services Capital – Service Equipment) shows capital and minor fixed assests of $12 million in 2010 and $8.8 million in 2011. The investment is required to replace end of life and obsolete equipment and to provide new equipment consistent with the planned work program levels including initiatives of the GEGEA. The investment includes purchases of: minor specialized transportation equipment such as snowmobiles, all terrain vehicles, boats etc. to transport crews to off-road work sites; measuring and testing equipment; tools; and relatively large tanker units.

Please provide details on the purchases and costs related to service equipment 1 in 2010 and 2011 that are attributable to specific initiatives of the GEGEA.

Response

The Green Energy Plan as included in Exhibit A, Tab 14, Schedule 2 provides a high-level overview of the major 'green' programs and initiatives that Hydro One will be undertaking. This exhibit is only intended to summarize the program and project investments required because of the Green Energy Act. This exhibit consolidates information found in the exhibits addressing the broad areas of Sustainment, Development, Operations or Shared Services OM&A and Capital.

The planned purchase of Service Equipment in 2010 and 2011 is driven by the overall increased demand resulting from the growth in the transmission and distribution work programs including the initiatives of the Green Energy Act.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #31
List 1

Interrogatory

4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Reference: Exh D1/Tab 3/Sch 9/Page 5
Reference: Exh D2/Tab 2/Sch 3/IDS C4

IDS C4 (Shared Services Capital – Transport and Work Equipment) shows capital expenditures of $133.4 million in 2010 and $74.1 million in 2011. The investment is required to meet vehicle fleet requirements arising from increasing work programs and required staff levels including support for the GEGEA.

a) Please provide details and costs for the additional equipment requirements for the Distribution and Transmission internal work requirements for the GEGEA ($83 million).

b) Please provide information on the number of additional vehicles and light and heavy equipment required to support the initiatives of the GEGEA.

Response

a) and b) Please refer to Exhibit H, Tab 7, Schedule 92.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #32
List 1

Interrogatory

4.3 Is the proposed level of 2010/2011 Shared Services and Other Capital expenditures appropriate?

Reference: Exh D2/Tab 2/Sch 3/IDS C2

The budget for the Head Office Real Estate project seems quite large. It would appear to exceed $200/ft225.

a) Please identify the major activities includes in this project, along with cost and timing (2010 or 2011).

b) Please identify which of the proposed project costs are totally non-deferrable (such as furniture for new staff) and which are potentially deferrable.

Response

a) The Head Office Capital Investment consists of leasehold improvements and replacement furniture systems. The gross leasehold improvements are estimated in total cost of $19.4M and $20.4M in years 2010 and 2011 respectively. The total leasehold improvements costs are indirectly offset by tenant improvements allowance committed by the Landlord of $11.6M including additional base building improvements. This includes estimated $3.2M for base building improvements costs to be refunded to Hydro One by landlord as part of tenant inducements. The Landlord tenant improvements allowance will be amortized over the eleven year term of the lease and treated as a credit to operating expense, which has been reflected in operating budget. The furniture systems are estimated in total cost of $7.7M in both years 2010 and 2011.

b) The planned improvements are necessary as major head office building infrastructure elements are now at the end of their life and require replacement. (This includes the raised flooring, which presents a health and safety issue with increasing number of tripping hazards.) The project costing reflects continuance of the open office environment, completion to standard commercial finishes and commitment to LEED certification. Similarly, furniture systems were acquired from the previous tenant, refurbished and are also now considered to be at end of life. The planned tenant improvements are part of the newly negotiated lease agreement.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #33
List 1

Interrogatory

Issue 7.4 Are the proposed rate impact mitigation plans appropriate and are the resulting customer bill impacts reasonable?

Reference: Exh G1/Tab 7/Sch 2

This Schedule makes no mention of Hopper foundry, which time of use rates 1 were to be left in place until April 30, 2010 (ref: EB-2007-0681 Decision With Reasons, page 43).

a) Please explain Hydro One's proposal for rates for Hopper Foundry effective January 1, 2010 and May 1, 2010 if Hopper Foundry's rates are not to change on Jan 1, 2010.

b) Please calculate the total bill impact on Hopper Foundry when Hydro One proposes its rates to change.

Response

a) Hydro One proposes that Hopper Foundry be served under an approved customer class on a non-TOU basis, effective January 1, 2010. If the current distribution rates do not change on January 1, 2010, the current interim TOU rates will continue to be applied to Hopper Foundry until the new 2010 Distribution rates become effective.

b) Based on the hourly metered demand (kW) for Hopper Foundry from July 2008 to June 2009, the average monthly on-peak demand is 8% of the average monthly non-coincident peak demand. On a TOU basis, the distribution rates are applied to the on-peak monthly demand. Non-TOU applies the same distribution rates to the non-coincident peak monthly demand. The substantial difference in billing demands, along with the proposed increase to the existing approved distribution rates result in a 190% increase in total bill for Hopper Foundry.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #34
List 1

Interrogatory

Issue 8.1 Is the 2010/2011 smart meter O&M and Capital budget appropriate?

Reference: Exh F1/Tab 1/Sch 3/Page 2

Hydro One's target is to have Smart Meters installed for all 1.2 million customers by the end of 2010.

Please provide a summary of the number of smart meter installations (in service and planned) by customer class and by year.

Response

The table below summarizes the smart meter installations by customer class and by year.

Rate Class	2006	2007	2008	2009 Planned	2010 Planned	Total
Farm	291	3,812	20,985	38,972	25,215	**89,275**
General Service	712	10,563	29,071	33,684	29,429	**103,459**
Residential	26,051	195,706	382,116	194,875	44,055	**842,803**
Seasonal	546	12,750	23,847	102,469	16,301	**155,913**
TOTAL	**27,600**	**222,831**	**456,019**	**370,000**	**115,000**	**1,191,450**

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #35
List 1

Interrogatory

Issue 8.1 Is the 2010/2011 smart meter O&M and Capital budget appropriate?

Reference: Exh F1/Tab 1/Sch 3/Page 2

Hydro One indicates that "In 2010 we plan to install 115,000 smart meters in locations that are feasible using current technology."

Please complete the following table.

Customer Class	# of Smart Meter Installations Not Feasible	% of Total	Explanation of "Not Feasible"

Response

The Smart Meter project is planning on installing all 115,000 meters in 2010. There may be instances where replacing the meter is not feasible (e.g. inside meter with no access), however we do not have any "not feasible" meters identified at this time.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #36
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Exh A/Tab 14/Sch 2/Page 1 and 6

On Page 1 Hydro One states that the Green Energy Plan is based on the Company's experience with the development of renewable energy generation connections since 2006. The table on page 6 shows the status of processing requests for Connection Impact Assessment (CIAs). The number of CIAs requested (1553) represent about 12,000 MW of capacity; however 42% of the CIA requests are outside the threshold for processing because of technical limitations.

a) What is the estimated capacity (MW) of the 869 CIAs completed since 2006? What is the estimated capacity of the 147 CIAs with connection cost estimates completed?

b) Please provide a project list and breakdown of the total number of CIAs completed by generator size, type, location and cost.

c) Please expand the table to show dates ending: Dec 2009, Dec 2010, Dec 2011, Dec 2012, 21 Dec 2013, and Dec 2014.

Response

a) and b)
See response at Exhibit H, Tab , Schedule 63 capacity and the response at Exhibit H, Tab 10, Schedule 6 (number, size, and location).

c) Hydro One cannot predict the number of CIAs that will be submitted or will have connection cost recovery agreements and connection cost estimates completed in any given year, as this depends entirely on the customers.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #37
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Exh A/Tab 14/Sch 2/Page 5

Hydro One indicates that the Green Energy Plan follows the Company's strategic drivers of Innovation, Stewardship, Excellence and Safety and that Innovation drives reductions in the carbon footprint of the electricity industry.

a) Does Hydro One have an established carbon quantification /monitoring program in place to track and evaluate Hydro One's existing and proposed initiatives in order to quantify reductions in its carbon emissions.

b) If so, what are the anticipated carbon offsets resulting from the initiatives/expenditures in the Green Energy Plan?

Response

a) Hydro One does not have a formal carbon quantification/monitoring program in place at this time. A carbon footprint exercise was conducted in 2009 which provided baseline information on our carbon emissions in 2007 and 2008. Internal initiatives to reduce carbon emissions from various aspects of our operations are underway, and efforts have recently begun to define quantification and tracking program to capture the savings from these initiatives.

b) Anticipated carbon offsets are not yet available.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #38
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Exh A/Tab 14/Sch 2/Page 10

On page 10, Hydro One states that it has taken an active role in development forums to develop concepts and standards of Smart Grid and regularly commissions universities and other consultants to examine, test and report on specific aspects of Smart Grid initiatives and technologies.

a) What specific aspects of Smart Grid initiatives have been examined, tested and reported on?

b) Please provide a detailed list of the commissioned work, the objectives of the work, cost of each study, and the completion dates.

c) How have the results from these studies been incorporated into the development of Hydro One's Green Energy Plan?

Response

a) Smart Grid in its broadest sense includes advanced metering infrastructure (AMI) and conservation and demand management (CDM). Hydro One is in the final stages of implementing its AMI system including full integration with the provincial MDMR and providing customers time-of-use billing.. We have also undertaken several programs that have been reported to the OEB on CDM. The additional drivers introduced by the Green Energy and Green Economy Act (GEGEA) will require Hydro One to expand its efforts in examining and testing smart grid intiatives and technology, particularly with respect to incorporating large numbers of distributed generators into our distribution system (which will require advancements in monitoring, protection and control) and with respect to customer enablement (to better understand the tools and programs that will help customer's better manager their bills under time of use rates while at the same time further contributing to a culture of conservation).

b) Hydro One has participated in the Ontario Smart Grid Forum (lead by the IESO), which has lead to the publication of a report that was completed early in 2009 and is provided as Attachment 1 to Exhibit H, Tab 13, Schedule 15. Hydro One also

organized and lead a group consisting of provincial utilities to request spectrum allocation changes from Industry Canada – this group has been successful in acquiring a 30Mhz allocation that can be used for the protection and operation of critical electrical infrastructure. As well, Hydro One actively participates in forums such as CIGRE, EPRI, IEC, IEEE and other associations including utilities and universities over the last couple of years, which has resulted in the following work:

- IEEE-PES: Comprehensive design and testing of realistic customer-driven microgrids (Florida State University)
- Distribution Automation: Movement From Today's Distribution System to Tomorrow's Smart grid (Hydro-Quebec)
- EUCI: Implementation of the Smart Grid for Canadian Electric Utilities
- NIST: Framework and Roadmap for Smart Grid Interoperability Standards

The cost of most of the above has been minimal to date as we generally assign internal staff to lead and / or participate in consensus building.

Going forward we expect we will be required to commission industry experts to perform studies related to the design, build, and implementation of smart grid technologies specific to our system and requirements. The funding details for this future work is outlined in Exhibit H, Tab 9, Schedule 13.

c) Hydro One's Green Energy plan aligns with the GEGEA which stresses the need for much more DG and CDM. We are leveraging what we've done with smart meter (for example utilizing aspects of the communications network including private broadband backhaul for additional smart grid applications) as well as CDM pilots and plan to build on this in the Smart Zone as the next stage of implementation. Work with the associations listed above are directly tied to standards and technologies in support of smart grid development and has assisted in defining the scope of the anticipated Smart Grid investments included in this Application.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #39
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?
Interrogatory #39

Reference: Exh A/Tab 14/Sch 2/Page 9
Hydro One has identified regions where the potential for renewable generation development is the highest.

a) Please provide a schematic showing the areas of the Province where generation development is the highest and show the existing and proposed generation connections in these areas by capacity category (large, mid-size, small).

b) What is the number of technically feasible renewable generation projects where there are no transmission constraints?

Response

a) Hydro One expects that the regions where the potential for renewable generation development is the highest would be those regions which the OPA has designated as Orange Zones because transmission constraints have been identified. Information by area and by generator size is not available.

b) Hydro One cannot provide the number of technically feasible renewable generation projects where there are no transmission constraints because the size and type of the projects that will apply through the Feed-In Tariff program are not yet known.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #40
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Exh A/Tab 14/Sch 2, Page 6

Hydro One projects that over 3,500 MW of renewable generation will be connected by 2011 and an additional 3,500 MW will be connected by 2014.

Based on Hydro One's experience, what percentage of this capacity will be made up of wind, solar, waterpower, renewable biomass, bio-gas, landfill gas?

Response

Hydro One cannot forecast what percentage of this capacity will be made up of wind, solar, waterpower, renewable biomass, bio-gas, landfill gas because we have not yet seen the applications under the Feed-In Tariff (FIT) program. Since the pricing and the program requirements for some of these types of generators is different under the FIT program than they were under the Renewable Energy Standard Offer (RESOP) program, it will impact the business plans for these generators. Therefore, historical data cannot be used to reliably forecast this split.

Historical data (by MW and by resource type) can be found in response at Exhibit H, Tab 3, Schedule 63.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #41
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Exh A/Tab 14/Sch 2, Page 7

Hydro One indicates that the renewable energy generation forecasts of 3,500 MW to be connected by 2011 and an additional 3,500 by 2014 were based in part on Hydro One's experience with the timeline for the different stages of the connection process.

Please provide an estimated outline of the typical timelines to connect large (10 MW to 50 MW), mid-size (500 kW to 10 MW), small generators (<500 kW) and micro-generators (< 10 kW).

Response

The typical timelines are:

Large Generator

- The target timeline from FIT application to FIT contract is 60 days, according to the OPA.
- Hydro One estimates that it will take 60 days to complete the Connection Impact Assessment (CIA), provided it is not impacted by the Customer Impact Assessment
- A System Impact Assessment (SIA) and a Customer Impact Assessment will also be needed. The estimated timeline is 150 days to complete both of these studies. At that point, all information in the CIA can also be considered complete.
- From the time that the CIA is completed, the generator has 6 months to complete its Cost Connection Agreement (CCA).
- Hydro One cannot estimate the time from the completion of the CCA to in-service of the generator, as the in-service date is set by the generator.

Mid-Size Generator

- Same as for Large Generator, except SIA and Customer Impact Assessment is not Typically required.

Small Generator

- Same as for Mid-Size Generator.

Micro Generator

- Same as for Small Generator, except a CIA is not needed for generators that are 10kW or less in size.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #42
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Ex A/Tab 14/Sch 2/Page 28, Section 4.3

a) Please identify whether the investments in systems discussed on page 28 lines 25 to page 29, are separate and apart from the capital projects listed as IT4 and IT 5 in Exhibit D2/Tab 3/Schedule 3, or are part of these projects.

b) Does Hydro One plan to purchase PHEVs as part of the Owen Sound Smart Zoe project, or are third party suppliers providing the vehicles.

c) If Hydro One is planning to purchase PHEVs, please indicate proposed quantity and cost.

d) If Hydro One is planning to purchase PHEVs, please indicate whether the purchase cost is included in the Transport and Work Equipment capital budget or is it a separate purchase.

If Hydro One is planning to purchase PHEVs, please indicate how it plans to gain evaluation experience. For example, how will Hydro One assign or allocate PHEVs to evaluators

Response

a) Investments are separate and apart from those listed in IT4 and IT5.

b) Hydro One plans to issue an RFP in the fall of 2009. Included in the RFP is Scenario F related to PHEV's. There has been no decision at this time to purchase PHEV's and any future decision will depend upon the results from the RFP. One objective of any PHEV work would be to better understand the utility impact of such devices including transformers, phase balancing and power quality implications.

c) There is no decision to purchase at this time.

d) There is no decision to purchase at this time. Further, the results of the RFP will help determine the nature of the evaluation, including how or if they will be allocated to evaluators.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #43
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Ex D1/Tab 3/Sch 3/Page 23

Hydro One indicates that the "Smart Zone work will be implemented through a combination of work performed by Hydro One Distribution staff and external service providers.

Please provide a list of the specific work activities in 2010 and 2011 that will be performed by Hydro One staff and external service providers and include a breakdown of costs.

Response

Please refer to Exhibit H, Tab 9, Schedule 13 for information about Smart Grid program costs.

There is no estimate available that breaks down the costs for work to be performed by Hydro One and other service providers at this time. Subject to the completion of the RFP, the expectation is that Hydro One will do the following types of work:

a) Project leadership through the provision of Hydro One Management staff in key project roles such as Project Sponsor, Steering Committee, Project Director, Line of Business leads and other key positions as required.
b) Subject Matter Experts (SMEs) from Hydro One to provide input on specifications and requirements and perform product testing and evaluations.
c) Field work as required to install and maintain equipment.
d) Other tasks associated with major projects such as Finance (budgeting, A/R, A/P), Organization Alignment (development and delivery of communications and training), Infrastructure (Office space, IT, logistics, etc.).

The expectation is external service providers will perform the following types of work;

a) Overall project management, coordination and integration support.
b) Solution architect support.
c) Provision of SMEs appropriate for the technology, solution and implementation.
d) Technical and support resources to design, develop, construct and implement solutions specific to project needs, including IT (software and hardware), tools, devices, reports, etc.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #44
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Exh A/Tab 14/Sch 2, Page 29

Hydro One plans to establish a "Smart Zone" sandbox in the Owen Sound area as a testing ground for piloting new Smart Grid technologies and systems.

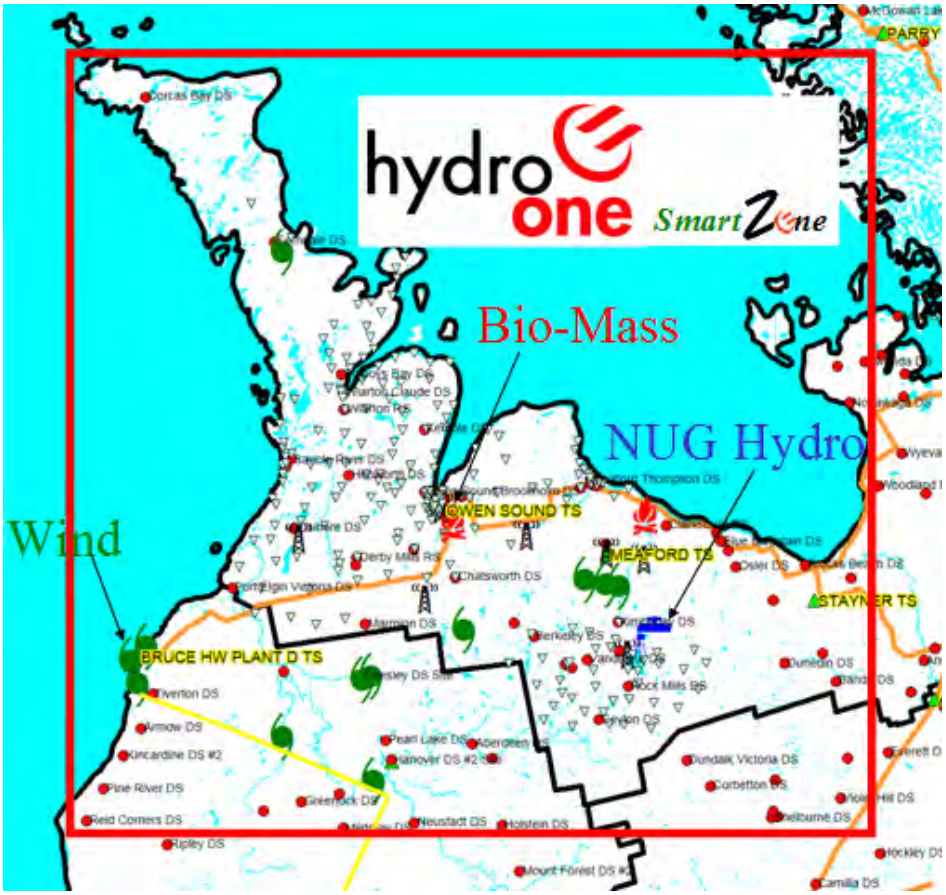
a) Please provide the geographical boundaries for the study.

b) Spending on the Own Sound Smart Zone Pilot is forecast to cost $12.5 million in 2010 and $42.8 million in 2011. Please provide a complete and detailed list of pilot projects and expenditures.

c) Please rank the projects in order of importance.

Response

a) The Smart Zone boundaries are shown in the diagram below. They extend 120 kM by 120 kM



b) Hydro One is planning to issue and RFP in the fall of 2009. The RFP will focus on a number of scenarios which will drive our decision on specific expenditures in the Smart Zone. Please refer to Exhibit H, Tab 12, Schedule 46 for more information about the RFP. Please refer to Exhibit H, Tab 9, Schedule 13 for more information about costs and projects.

c) Referencing the RFP scenarios in Exhibit H, Tab 12, Schedule 46, the immediate focus is on "Scenario A Distributed Generation Integration" to meet FIT connection forecast. A second high priority is "Scenario E Customer Enablement" since beginning in 2010 we would like to provide customer the tools necessary to help them manage their consumption and contribute to conservation culture. Following that, "Scenario B Distribution Reliability / Operations Improvement (OGCC)" and "Scenario C" Outage Restoration Optimization (Field Focus) would leverage the infrastructure used in A and E to provide the customer with better service and reliability as well as increase productivity. "Scenario D Distribution Network Asset Planning and Tools" would provide the data for better planning and decision making to optimize results – this scenario also will assist with the delivery of the large number of studies required for Scenario A (enabling DG). "Scenario F Plug-in Hybrid Electric Vehicles (PHEVs) is helpful in determining the system impact of these devices.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #45
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Ex D1/Tab 3/Sch 3/Page 2, Table 1

Table 1 provides a summary of net development capital including Smart Grid expenditures. Please provide an update/status on the proposed Smart Grid activities and expenditures in 2009 of $15.2 million and include the anticipated actuals at year-end.

Response

Please refer to Exhibit H, Tab 9, Schedule 50.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #46
List 1

Interrogatory

Issue 9.1 Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?

Reference: Ex D1/Tab 3/Sch 3/Page 23
As part of Hydro One's Smart Grid Plan, Hydro One is working on an RFP "to seek interest from vendors to participate in SG investments".

a) When does Hydro One expect to complete the RFP and issue the RFP?

b) Please provide a terms of reference for the RFP to show the purpose, objective, timelines, key milestones and expected benefits of the RFP?

Response

a) The RFP is planned to be issued in the fall of 2009.

b) Please see Attachment 1.

Summary of Scope of Hydro One Smart Grid RFP

Introduction

Hydro One is preparing a Smart Grid RFP as part of our strategy Green Energy and Green Economy Plan. As part of the RFP, we will be seeking qualified vendors to define, test, evaluate and, ultimately, build a province wide "Smart Grid."

It is Hydro One's intention to select partners today to work with us through the entire process. However Hydro One's approach is "staged," with a number of phases, each followed by an evaluation process, a go/no-go decision, and the development of a business case and statement of work to proceed to the next phase. We must be satisfied at each stage of the viability of proceeding to the next phase.

Smart Grid Definition

A Smart Grid is a flexible (intelligent) Transmission and Distribution system that efficiently enables "green" and distributed energy production, encourages conservation, and enhances reliability; in a manner that provides better customer service (satisfaction) through cost-effective innovative electricity delivery technology, design, services and information. The Smart Grid represents the technological convergence of the high and low-voltage systems. The intelligence and flexibility of the transmission system will be incorporated into the distribution system to provide seamless and efficient operational control across all our grid assets.

Hydro One is in a unique position to design and build a smart distribution grid in Ontario. We have the equivalent communications and control technology in place on our transmission system. We also own and operate a province-wide fibre optic network, which can be leveraged to provide essential communications infrastructure to enable new smart functions and applications across our system.

Expected Benefits

Hydro One expects that its investments in Smart Grid will bring the following benefits:

- **Support for the Provincial Energy Strategy**
  Hydro One's Smart Grid investments will fully support and enable the energy policy objectives of the Government for Ontario, in terms of clean, reliable, and affordable power supply. Hydro One will facilitate low-carbon policies that encourage investment in renewable distributed generation by developing controls integrated through its Smart Grid that optimize the operation of these generators connecting on

its system. With the increase in smaller and more distributed generation, there is a need to implement Smart Grid concepts which will support continued reliable and safe operation of the distribution system. Increasingly, technology will allow visibility and control of distributed generators.

- **Improved Worker and Public Safety**
  Hydro One is committed to creating and sustaining an injury-free workplace and maintaining public safety. Continued safe operation of the distribution system will be facilitated by the control and communications infrastructure of the Smart Grid that will require less manual switching and other field work.

- **Increased Customer Satisfaction – reliability**
  Hydro one will continue its efforts to improve the satisfaction of its customers, and from our research we know that our customers' satisfaction is driven in part by the reliability and quality of power delivery. New two-way communication will give Hydro One the capability to improve restoration times, provide automatic load control and peak shaving.

- **Increased Customer Satisfaction –energy consumption and costs**
  Our customers expect us to deliver services that enable them to better manage their electricity use. Smart Grid will allow us to deliver innovative programs to allow customers to understand and reduce their energy consumption and costs, and will enable Demand-Side Response Incentive Programs.

- **Return on Investment**
  We are committed to keeping rates as low as possible for our customers, while we are expected to deliver income and dividends to the Province. This is only possible through continuous focus on reducing costs, effectively managing and increasing productivity. Therefore we expect our Smart Grid investments to earn a positive return on investment, through improved cost efficiency and full regulatory recovery.

- **Technological Innovation and Risk Management**
  Hydro One embraces innovative approaches and new technologies, yet maintains a prudent perspective and keeps focus on flexibility when choices are made. Consequently, Hydro One will follow a deliberate, staged approach, utilizing pilots and targeted research to demonstrate understanding of, and commitment to, smart technology. Hydro One will use proven off-the shelf technologies, recognizing that technologies in this area may change rapidly over the next 5 years and hence the need to maintain flexibility and use open non-proprietary technology solutions.

Approach

Similar to our approach for Smart Meters, we are looking to leverage back office systems and communications that are required for government initiatives such as DG Integration and CDM for other business purposes. In order to understand how these smart grid requirements can best be achieved, Hydro One proposes to proceed with a "Smart Zone"

sandbox in the Owen Sound area to test new technologies and systems prior to recommending a corporate wide deployment.

An RFP is being prepared where the entire work statement is broken down at a high level into six Business Scenarios. Each of the scenarios represents an opportunity for end-to-end integrated solutions (people, processes and technology) that will impact and implicate one or more of Hydro One's existing and/or new platforms and resources. This includes Enterprise IT, Real-time Operations (monitoring and control / power quality), field forces tools, new back office systems (Distribution Management System (DMS), Operational Data Store (ODS), Event and Transaction Management System), integration of back office systems (Smart Meters, Outage Management System (OMS), Geographic Information System (GIS), DMS, ODS), and electrical power field devices. Each solution is expected to deliver specific business benefits, and each relies on its own elements of technology, process, and infrastructure.

Hydro One has chosen the business scenario approach to also provide the proponents the flexibility to design and deliver business solutions geared toward meeting the needs of a large scale, diverse and low density distribution business. Rather than being overly prescriptive in terms of detailed functional and technical requirements Hydro One is looking to the market place to provide scalable solutions that cater to the radial distribution business.

Scenario Descriptions

- **Scenario A: DG Integration**

A significant amount of new generation capacity is being planned through the installation of DG facilities on HONI's distribution system. An integrated system level view of the Protection and Control ("P&C") requirements at various voltage levels is required. With Smart Grid infrastructure in place such as WiMax, IEC61850 compliant devices, etc., more "Plug and Run" solutions are possible.

Maximizing renewable energy (wind / solar / hydroelectric / biomass) is one of the leading objectives. To this end, options to reconnect DGs automatically, transfer DG control to other feeders, or store excess DG outputs shall all form an integrated solution. All this would have to happen within the limits of power quality, voltage regulation, VAR support and operational standards enforced by various regulatory codes in Ontario. Therefore, addition of other devices, such as energy storage systems, voltage support / VAR support systems and dynamic controllers should be a part of the solution.

There will be a need to monitor and control intermittent resources at a group level (e.g. all provincial wind farms as a group). Renewable energy sources would need to be optimized based on operational needs from time-to-time. Algorithms for such energy source optimization will also be needed.

Over the next few years, more DGs will be eligible and waiting to connect. It is anticipated that the deployment of Smart Grid technologies will be able to reduce the impact of system constraints thereby allowing more DGs to be placed on the various feeders. As this transpires, it will be possible to examine load / supply balancing in a local area to ensure stable operation as a stand-alone microgrid. This could involve the use of distributed intelligence, distributed microcontrollers and control algorithms to enact changes to both the supply and demand side. Such tools could be at the utility end, at the district level, and / or at the customer level.

Solutions addressing this scenario should interface with existing power devices (such as breakers, regulators, and reclosers), Distribution Management System / Supervisory Control and Data Acquisition ("DMS / SCADA") controls, Conservation Demand Management ("CDM") / Demand Response ("DR") and telecommunications.

- **Scenario B: Distribution Reliability/Operations Improvement (OGCC)**

The Distribution System will be automated in varying degrees to provide for real time monitoring and control and automatic restoration, and optimize operations to reduce overall utility costs and improve customer satisfaction.

Within Distribution Stations ("DS"), SCADA will be enabled with Intelligent Electronic Devices ("IED") deployments on various pieces of equipment augmenting with video feeds to provide visual confirmation of station perimeter security and equipment status. P&C configurations will be IEC 61850 protocol compliant, which will allow for high-speed deterministic protection beyond current Distributed Network Protocol ("DNP") monitoring and control abilities. Under-frequency Load Shedding ("UFLS") protection for load shedding at DSs versus TSs will prevent net generation loss.

Various automated field devices will also enable the following:

- Volt / VAR optimization will be achieved through installation of and control of capacitor banks and integration with the Network Management System ("NMS") / DMS.
- Remote group relay setting changes on Transmission Station ("TS") feeder breakers and line reclosers.
- Remote control of mid-feeder devices (e.g. reclosers, capacitors, switches, etc.).
- Design and installation of remote control of adaptive protections to allow DG connection on alternate feeds.
- Installation of power quality monitors on medium voltage distribution (44 / 27.6kV feeders = "M Class") and low-voltage distribution ("F Class") class feeders for power quality metering.
- Installation of electronic fault indicators on sub-transmission (medium-voltage) and distribution class feeders for calculation of distance to fault.
- Bi-directional regulation.
- Feeder analysis to ensure adequate relay coverage and voltage for any switching configurations in real time and study mode.

To enhance operator control there is a need for two-way conversions of distribution data between single line schematics and a Geographical Information System ("GIS") representation, as well as situational awareness by wide area visualization.

This solution should interface with system and station monitoring / control / automation devices (i.e. voltage regulators / capacitors, temperature / vibration), telecommunications, NMS, GIS, AMI / Operational data store and the SAP Enterprise Asset Management system.

- **Scenario C: Outage Restoration Optimization (Field Focus)**

Customer outage duration will be minimized by leveraging the Scenario B station / lines automation with quicker more efficient fault restoration by enhancing workforce mobilization.

Outage Management will require integration of various enterprise systems (e.g. SCADA, GIS, AMI, CIS ["Customer Information Systems"], Workforce Management System ["WFM"], OMS ["Outage Management System"] and customer portal). These systems will be utilized to enable efficient business processes. SCADA, feeder devices (bellwether meters, fault indicators), AMI events, Interactive Voice Response ("IVR") and customer call tickets will need to be visually represented to predict and identify sustained interruptions and will improve restoration times via normal and alternate switching configurations and faster crew response on the medium and lower-voltage Distribution system. Near real-time Distribution device connectivity will be Geo-Spatial and Schematic based and made available to the OMS for Ontario Grid Control Centre ("OGCC") Dispatchers and on Manager Desk Tops ("MDTs") for crews.

AMI and feeder device (bellwether meters, fault indicators) events and data will be telemetered over the extended wireless and communication network. Filtering and analysis of all AMI and Feeder Device data and events will be done to confirm forced outages and to throttle data in high-volume times, then delivered to OMS. Planned meter disconnects set up in CIS (CSS) will be distinguished from unplanned power outages, reconciled and filtered off before entering the OMS to avoid sending crews unnecessarily. Additionally, field workers will be able to identify and toggle meter disconnect status on MDT prior to disconnecting the meter from the socket in order to flag meter outage and assist in the filtering off of the last gasp before reaching OMS. There will be a bidirectional interface with OMS and capability to query and ping AMI devices and other network equipment. The OMS and AMI operator will be able to distinguish and indicate if there is a communication network issue or a power network hierarchy issue.

Field forces location will be known by GPS coordinates and viewed on a geographic display. Lone worker personal devices will be worn outside of vehicles and the location will be known and displayed. A distress signal from a PDA will alert at the OGCC.

Crews will be dispatched by proximity / availability / skill set. Via WFM, crew demand work (currently WEP CAD) and trouble work (currently Outage Response Management System ["ORMS"] CAD) will be integrated and made available on a mobile data terminal. GIS-based maps and restoration status will be enabled. OMS Operators and AMI operators will have access to view demand and trouble work. Crews will update location, Estimated Time of Arrival ("ETA"), Estimated Time of Response ("ETR") and causal / repair status in real time that will be made available to customers via the notification processes by updating the OMS (ORMS). Accomplishment reporting, time reporting, trouble sheet reporting, asset and material update in SAP will be executed in near-real-time via WFM.

Upon restoration, the system will confirm restoration of all downstream points. In parallel, customers will be notified of outage status and details through a variety of media (e.g. In-home Displays ["IHD"] / IVR / E-customer, Personal Digital Assistant ["PDA"], etc.).

Both real time and historic data will be used for business reporting and analytics. Ad-hoc and canned reporting will include analytics of power quality, theft of power, feeder performance and to trouble shoot outage inquires.

Solutions which address this scenario should interface with telecommunication networks, CGI Outage Management System ("OMS") (ORMS), CGI Workforce Execution Program ("WEP") Computer-Aided Dispatch ("CAD"), AREVA Energy Management System ("EMS") Network Management System ("NMS"), Enterprise Service Bus (iHub), AMI, Operational data store, Reporting tools, WFM, CIS Customer Service System ("CSS"), GIS and the SAP Enterprise Asset Management system.

- **Scenario D: Distribution Network Asset Planning and Tools**

Together the Smart Grid scenarios make available to HONI a huge amount of operational data. An operational data store will be developed to capture and archive all real-time operating data gathered through the other scenarios' solution sets, and integrate it with other, existing data sources.

Data-mining and analytical tools will be made available to enable:

- Better real-time mitigation of system events at the OGCC.
- Better planning of electricity system expansion and sustainment programs by System Planners.

This scenario's solution sets may address and integrate:

- Dx feeder connectivity models and characteristics.
- Spatial Dx asset representation (i.e. GIS) for any historical point in time.
- Integration with station and feeder electrical data store (voltage, current, kWhr, kvar).
- AMI / MDMR customer load data.

- Reconciliation of data sources.
- Historical trend data.
- Equipment duty cycle, failure, and equipment operating data.
- Integrated with existing Asset Management planning tools and processes.

Solutions which address this scenario must interface with Distribution planning tools (i.e. CYME network analysis software), GIS, monitoring / control devices (i.e. voltage regulators / capacitors, temperature / vibration), telecommunications, DMS, AMI / Operational data store, Enterprise Asset Management and the SAP Enterprise Asset Management system.

- **Scenario E: Customer Enablement**

Customers will begin migrating to time-of-use ("TOU") rates beginning in early-2010. Tools, devices and information will be made available to customers to help them better understand and manage their electrical consumption and peak demand.

With evolving programs, there is a need to confirm the capabilities of the AMI system in conjunction with TOU and a number of CDM options and to investigate alternatives. Customers want choice – no one device or program will suit all customers. As such there is a need for:

- Broad array of technology / products including, but not limited to, two-way communicating programmable thermostats, IHDs and remote appliance controllers (such as smart appliance controllers, multi purpose gateways, etc.).
- IHDs for CDM and planned outage / other notifications.
- Web / local presentment of information and central / utility or customer control / maintenance of devices and automated signal / responses.
- The ability to monitor and assess customer response to and acceptance of these devices.
- Effective distribution channels and provisioning of devices.
- Evaluation, monitoring and verification of CDM results / programs.

The solution should interface with telecommunications, AMI / Operational data store, Web Presentment tools, CDM devices and control software, CIS, OMS and CRM.

Proponents shall consider the following components in their response with regard to CDM solution components:

- CDM Device.
- CDM Head-End.
- CDM API / Gateway service.
- CDM Consumer Portal.
- CDM Communications with Device.

- **Scenario F: Plug-in Hybrid Electric Vehicles (PHEVs)**

The advent of Plug-in Hybrid Electric Vehicles (PHEVs) will cause utilities to not only address infrastructure modifications but also to potentially widen its relationship with its customer base. HONI operates in both a very urban setting (via Hydro One Brampton) and the traditional rural distribution areas it has served for well over a hundred years. Solutions addressing this scenario will focus on the impact of PHEVs on:

1. Fleet Management

    a) Lowering overall carbon footprint.
    b) Using less fuel.
    c) Reducing noise pollution.

2. Enablement of consumers to use PHEVs via:

    a) In-home load prioritization and management.
    b) 3rd party contractor engagement.
    c) ESA certification.
    d) Utility notification of intent to purchase so the utility can manage load / infrastructure impact.

3. Utility Network Impact

    a) Both rural and urban system impacts due to PHEV proliferation.
    b) Customer transformer / DS / TS system modifications requirements.
    c) Phase balancing.
    d) Vehicle to grid (V2G) power quality implications.

Solutions for this scenario should interface with AMI / Operational data store, Electrical Safety Codes and the various industry charger characteristics.

Phases

Smart Grid expenditures will be prudently incurred using a phased project management approach as follows:

- Phase 0 – Project Definition and Setup. This will include a project governance plan, a statement of work for phase 1, a detailed phase 1 integrated plan including design, materials and resources and a business case for phase 1.
- Phase 1 – Implementation in the “Smart Zone”. This will be seen as the live “proving ground” for Smart Grid development over coming years; a platform on which proponents can demonstrate the viability and value of their solutions. This phase will include evaluation of the Phase 1 solution and possible refinement of requirements, an integrated phase 2 program plan and a business case for phase 2.

- Phase 2 – Full Implementation (province-wide roll-out) of Smart Grid. This is the enterprise roll-out of successful solutions conceived and developed in Phase 0 and proven through implementation in Phase 1 (having confirmed business benefits,) to the rest of the Hydro One service territory.

Expected Costs

As explained above, the approach Hydro One has chosen involves an RFP. This approach means some specific elements cannot yet be defined in detail until the response is received and evaluated. Exhibit H, Tab 9, Schedule 13 outlines expected costs based on the information available at the time the pre-filed evidence was filed.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #47
List 1

Interrogatory

Issue 9.3 Is Hydro One's methodology for allocating Green Energy Plan O&M and 34 Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?

Reference: Ex A/Tab 14/Sch 2/Page 2

Hydro One assumes that expansion and enabling investments for renewable 1 generation contained in the plan will be recovered through an external funding mechanism such as the Global Adjustment Mechanism (GAM).

What would the bill impacts be if an external funding mechanism was not available and Hydro One had to include the cost of the Green Energy Plan in the rate base for 2010 and 2011?

Response

Please refer to Exhibit H, Tab 13, Schedule 2, part d).

Canadian Manufacturers & Exporters (CME) INTERROGATORY #1 List 1

Interrogatory

Issue 1.2 Are Hydro One's economic and business planning assumptions for 2010/2011 appropriate?

Reference: Exhibit A, Tab 14, Schedule 1, Figure 1, page 2 and page 5, lines 1 and 2

Please produce in confidence, to participants who execute the Board's usual Confidentiality Undertaking, all of the materials presented to and approved by Hydro One's Board of Directors with respect to the Application currently before the Board. What we seek is the 2009 equivalent of what were filed as Exhibits KX1.7 and KX1.8 in the EB-2008-0187 proceeding pertaining to Hydro One's 2009 Distribution Rates.

Response

This information is filed in confidence with the Board and will be made available to intervenors that sign a Declaration and Undertaking form in accordance with the OEB Practice Direction on Confidential Filing.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #2 List 1

Interrogatory

Issue 1.5 Is the overall increase in 2010 and 2011 revenue requirement reasonable given the impact on consumers?

Reference: Exhibit A, Tab 3, Schedule 1, page 4; Exhibit A, Tab 7, Schedule 1, page 2; Exhibit A, Tab 14, Schedule 2, pages 1 to 3; Exhibit E1, Tab 1, Schedule 1, pages 1 to 5; Exhibit F, Tab 1, Schedule 3; and Exhibit G, Tab 8, Schedule 1

The evidence at Exhibit E1, Tab 1, Schedule 1, page 3, indicates that Hydro One's 2010 revenue requirement, after deducting external revenues, will be $1,1 02M, up some $116M from the Board approved revenue requirement for 2008 of $986M, net of external revenues. For 2011, the corresponding revenue requirement is expected to $1,216M or some $114M above the 2010 revenue requirement.

Exhibit E1, Tab 1, Schedule 1, page 3, indicates that $94M and $83M of the 2010 over 2008 increase in revenue requirement is attributable to the "Increase in OM&A" and "Increased rate base". Table 5 shows that, for 2011, the major causes for the further $114M increase in revenue requirement are "Increased rate base" ($47M), "Tax timing differences and other" ($31 M), ROE ($20M) and "Increased OM&A" ($15M).

We understand from Exhibit A, Tab 14, Schedule 2 that these revenue requirement increases reflect only a portion of the total costs contained in Hydro One's Green Energy Act ("GEA") Plan for 2010 and 2011, and that the revenue requirement related to a significant portion of the planned GEA spending will be collected through external funding mechanisms administered by the IESO and the OPA.

The evidence at Exhibit A, Tab 3, Schedule 1, page 4, indicates that the Total Bill Impacts on the average customer will be about 3% in 2010 and 4% in 2011.

We understand that these Total Bill Impact calculations include Smart Meter adders, but do not include "external funding" charges for the mechanisms administered by the IESO and the OPA, which will nevertheless appear in the total bill rendered by Hydro One to its customers.

It would appear that the amounts for these external funding charges in 2010 and 2011, and years beyond, will be significant and will materially increase from year to year.

In order to help manufacturers understand the entire bill impact of what is planned in 2010 and 2011, we request that Hydro One provide the following information:

a) Please indicate the approximate total number of electricity consumers currently served by Hydro One and the other electricity distributors shown on the map at Exhibit A, Tab 7, Schedule 1, page 2, with the total broken down between Hydro One customers and the customers of other LDCs;

b) Please provide revised Tables 2, 3, 4 and 5 in Exhibit E1, Tab 1, Schedule 1 to show the increase in Hydro One's revenue requirement for 2010 over 2008 and 2011 over 2010 on an assumption that the revenue requirement impact of all of Hydro One's planned GEA OM&A and capital spending in 2010 and 2011 will be recovered from Hydro One customers and not through any external funding mechanisms in whole or in part;

c) Provide a breakdown of the 2010 and 2011 revenue requirement to be produced in the tables above in a format comparable to that which appears at Section 2.0 of Exhibit E1, Tab 1, Schedule 1, at pages 1 and 2;

d) Please provide an estimate of the Total Bill Impacts 2010 over 2009 and 2011 over 2010 in the scenario described in subparagraph (b);

e) Revise the tables to be produced in response to the question in subparagraph (c) to eliminate and reduce to zero the equity of return component of "Return on Capital" and to eliminate and reduce to zero the PILs component of the Revenue Requirement in 2010 and 2011 so as to show the extent to which the total revenue requirement would be reduced in the absence of these items;

f) Are we correct that Hydro One's Total Bill Impact calculations of 3% for 2010 and 4% for 2011 reflect the increases in the Smart Meter adder in 2010 and 2011?

g) Please describe how a manufacturer can estimate, today, the total monthly and annual bill amount it will be likely to be called upon to pay in 2010 and 2011 including the amounts expected to be billed for external funding mechanisms administered by the IESO and the OPA;

h) Does Hydro One have any forecasts for 2010 and 2011 of the amounts ratepayers will be expected to pay for funding mechanisms administered by the IESO and the OPA? If so, please produce them. If not, then please indicate how electricity consumers can obtain such forecasts;

i) What criteria does Hydro One apply to determine whether the amount of a total bill increase is intolerable.

Response

a) The number of customers in 2008 can be found in the OEB's 2008 Yearbook of Electricity Distributors, published September 10, 2009. On page 10, the yearbook shows Total Customers of 4,693,045 and on page 60 the yearbook shows Hydro One Networks Inc. Total Customers of 1,187,253.

b) Below are the revised Tables 2, 3, 4 and 5 from Exhibit E1, Tab 1, Schedule 1 showing the increase in revenue requirement for 2010 over 2008 and 2011 over 2010 assuming the revenue requirement of the Green Energy Act will be recovered from Hydro One customers and not through any external funding mechanisms in whole or in part.

Table 2
Comparison of Revenue Requirements: 2008 vs. 2010 ($ Millions)

Line No	Description	Year 2008 OEB Approved	Year 2010	Difference
1	OM&A	466	560	94
2	Depreciation	230	263	33
3	Capital Taxes	8	4	(4)
4	Income Taxes	35	13	(22)
5	Return	289	318	29
	Total Revenue Requirement	**1,028**	**1,158**	**130**
6	Deduct External Revenues [1]	(42)	(48)	(6)
	Revenue Requirement less External Revenues	**986**	1,110	124

[1] External revenues addressed in Exhibit E1, Tab 1, Schedule 2

Table 3
Components of Change to Revenue Requirement

Previously OEB-Approved (2008) vs. Proposed (2010)Description	Amount ($ millions)
Increase in OM&A	94
Impact of increased rate base	91
Increase in asset removal costs	10
Increased external revenue	(6)
Tax timing differences and other	(19)
Lower ROE	(9)
Impact of lower capital tax rate	(8)
Lower cost of debt	(7)
Impact of lower income tax rate	(1)
Other (includes OPEB)	(22)
Total Change	**124**

Table 4
Comparison of Rates Revenue Requirements 2010 vs. 2011 ($ Millions)

Line no.	Description	Year 2010	Year 2011	Difference
1	OM&A	560	575	15
2	Depreciation	263	304	41
3	Capital Taxes	4	0	(4)
4	Income Taxes	13	40	27
5	Return	318	375	57
	Total Revenue Requirement	**1,158**	**1,294**	**136**
6	Deduct External Revenues [2]	(48)	(48)	0
	Revenue Requirement less External Revenues	1,110	**1,246**	**136**

[2] External revenues, addressed in Exhibit E3, Tab 1, Schedule 1.

Table 5
Components of Change to Rates Revenue Requirement:
Proposed 2010 vs. Proposed 2011

Description	Amount ($millions)
Impact of increased rate base	67
Tax timing differences and other	32
Higher ROE	21
Increased OM&A	15
Higher cost of debt	3
Impact of lower income tax rates	(4)
Impact of lower capital tax rates	(4)
Other	6
Total change	**136**

c) The following is the breakdown of the revenue requirement shown in part b).

2.1 OM&A Expense

	2010	2011
Sustaining	318.5	340.5
Development	21.7	21.9
Operations	16.7	17.6
Customer Care	106.3	102.4
Shared Services and Other Costs	92.1	88.1
Taxes Other Than Income Tax	4.7	4.8
Total OM&A	**560.0**	**575.2**

2.2 Depreciation and Amortization Expense

Depreciation	249.8	287.1
Amortization	12.9	17.0
Total Expense	**262.7**	**304.1**

2.3 Capital Taxes

Capital Tax	3.8	0.0
Total Capital Tax	**3.8**	**0.0**

2.4 Payments in Lieu of Corporate Income Taxes

Income before PILs	44.4	146.5
Tax Rate	31.00%	28.25%
Total PILs[3]	**12.5**	**39.9**

2.5 Return on Capital

Return on Capital	**318.2**	**374.9**

d) If the cost of the Green Energy Plan were included in Hydro One's rate base for 2010 and 2011, the bill impacts would be approximately 0.3% in 2010 and 0.6% in 2011.

e) Below is the breakdown of revenue requirement assuming the GEA equity component of return on capital and the GEA PILs component of revenue requirement in 2010 and 2011 are eliminated.

2.1 OM&A Expense

	2010	**2011**
Sustaining	318.5	340.5
Development	21.7	21.9
Operations	16.7	17.6
Customer Care	106.3	102.4
Shared Services and Other Costs	92.1	88.1
Taxes Other Than Income Tax	4.7	4.8
Total OM&A	**560.0**	**575.2**

2.2 Depreciation and Amortization Expense

Depreciation	249.8	287.1
Amortization	12.9	17.0
Total Expense	**262.7**	**304.1**

2.3 Capital Taxes

Capital Tax	3.8	0.0
Total Capital Tax	**3.8**	**0.0**

[3] Adjusted for R&D ITC and Ontario Education Credit see Exhibit C2, Tab 6, Schedule 1, Attachment A for detailed calculation

2.4 Payments in Lieu of Corporate Income Taxes

Income before PILs	44.3	145.8
Tax Rate	31.00%	28.25%
Total PILs[4],[5]	**12.4**	**39.2**

2.5 Return on Capital

Return on Capital	**316.0**	**365.9**

f) Correct. The total bill impact calculations of 3% for 2010 and 4% for 2011, as seen in Exhibit A, Tab 2, Schedule 1, Lines 7 and 8, reflect the increases in the Smart Meter adder in 2010 and 2011.

g) A manufacturer can estimate their total monthly and annual bill amounts, excluding any amounts to be billed via an external funding mechanism, by referring to Exhibit G2, Tab 4, Schedule 7 which shows the estimated New Total Bill (3rd column from the end) for the various rate classes at varying levels of consumption. As indicated in sub section 4 (1) of OReg 330/09, the amount to be collected by the IESO from market participants via an external funding mechanism will be based on the kilowatt-hours of electricity that are withdrawn from the IESO-controlled grid.

Given the Hydro One revenue requirement to be collected via external funding, per part h) below, and using a total of 148.676 GWh of energy consumed in Ontario in 2008 (per IESO reference), the amount to be collected from all electricity consumers is estimated to be $0.05/kWh in 2010, and $0.21/kWh in 2011. This is the Hydro One Distribution portion of the amounts expected to be billed for external funding mechanisms administered by the IESO and the OPA.

h) No, Hydro One does not have any forecasts for 2010 and 2011 of the amounts ratepayers will be expected to pay for funding mechanisms administered by the IESO and the OPA.

The revenue requirement to be collected via external funding from all electricity customers in the Province as a result of work to be undertaken by Hydro One Distribution is estimated to be $8.0m in 2010 and $30.7m in 2011 as shown on page 2 of Exhibit A, Tab 14, Schedule 2.

Hydro One's load on a GWh basis represents about 25% of the provincial total. Therefore, the estimated impact on Hydro One customers' bill is:

[4] Adjusted for R&D ITC and Ontario Education Credit see Exhibit C2, Tab 6, Schedule 1, Attachment A for detailed calculation

[5] Adjusted for removal of PILs related to the Green Energy Act in the amounts of $0.1M in 2010 and $0.7M in 2011.

	2010	2011
Revenue Requirement Funded by All Customers	$8.0M	$30.7M
Share that will be paid for by H1 customers	$2.0M	$ 7.7M
Increase as % of our Rev Req	0.2%	0.7%
Total Bill Impact	< 1%	0.2%

i) Hydro One does not have a criterion to determine if a specific bill increase amount is 'intolerable. The impacts on customers' bills are calculated in accordance with OEB guidelines which set the maximum allowable annual bill increase, and require utilities to implement mitigating measures if bill increases are above that threshold. Please also refer to the interrogatory response in Exhibit H, Tab 1, Schedule 8.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #3 List 1

Interrogatory

Issue 3.1 Are the overall levels of the 2010/2011 Operation, Maintenance and Administration budgets appropriate?

Reference: Exhibit C, Tab 1, Schedule 1; and Exhibit C, Tab 2, Schedule 1

Please provide copies of any studies Hydro One has in its possession, in confidence if necessary, which compare Hydro One's OM&A costs to industry benchmarks, including OM&A costs per customer benchmarks and all others.

Response

Hydro One does not perform benchmark studies relating to OM&A costs. We do have comparisons of O&M that can be seen in Exhibit H, Tab 1, and Schedule 32.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #4 List 1

Interrogatory

Issue 3.5 Are the 2010/2011 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

Reference: Exhibit C1, Tab 3, Schedule

A Navigant study was produced in Hydro One's last transmission case with respect to its staff costs. The study indicated that Hydro One's staff costs were materially higher than the benchmark. Please advise whether Navigant or any other consultant has provided a more recent benchmark study of Hydro One's compensation? If so, then please produce the study in confidence? If not, then please explain why the Navigant study has not been updated.

Response

The question refers to the 'Navigant study' but the proper reference is to the 'Compensation Cost Benchmarking Study' produced by Mercer/Wyman.

In the OEB's Decision with Reasons (EB 2006-0501), Hydro One was directed to provide 'useful and reliable information concerning Hydro One's compensation costs, and how they compare to those of other regulated transmission and/or distribution utilities in North America'. Hydro One issued a RFP and Mercer/Wyman were the successful bidder to produce this study. The compensation benchmark study was completed in 2008 and formed part of the filed evidence in Hydro One's Transmission filing EB -2008-0272.

This compensation study has not been updated for this Distribution filing. Benchmark studies of this magnitude are very costly. Given that not much time has passed since this study was completed, Hydro One does not believe it is prudent nor will it add any value to spend the required resources to update or conduct another study.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #5 List 1

Interrogatory

Issue 4.1 Are the amounts proposed for Rate Base appropriate?

Reference: Exhibit D1, Tab 1, Schedule 1, pages 1 and 2

Rate Base for 2010 is forecasted to be $4,835.6M and $5,145. 7M for 2011. What would the forecast Rate Base be for each year if it is assumed that all GEA capital expenditures are for the account of Hydro One's ratepayers? Please provide a revised Table 1 at Exhibit D1, Tab 1, Schedule 1, page 2 to reflect this assumed scenario.

Response

Below is the revised table from Exhibit D1, Tab 1, Schedule 1, page 2 to reflect rate base assuming all GEA capital expenditures are for the account of Hydro One ratepayers.

Table 1
Distribution Rate Base ($ Millions)

Description	**Test**	
	2010	**2011**
Gross Plant	7,303.2	8,006.5
Accumulated Depreciation	(2,708.8)	(2,927.7)
Net Plant	4,594.4	5,078.8
Cash Working Capital	301.3	306.6
Materials and Supplies Inventory	10.4	10.5
Smart Meter adjustment (a)	(2.3)	(2.3)
Distribution Rate Base	**4,903.8**	**5,393.6**

(a) This adjustment is to exclude from Revenue Requirement the working capital associated with Smart Meters that is currently tracked in a deferral account.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #6 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Reference: Exhibit D1, Tab 3

What is the approximate revenue deficiency impact in 2010 and 2011 of a $20M reduction in the 2010 capital budget and a $20M reduction in the 2011 capital budget?

Response

Removing $20M from the capital budget in both 2010 and 2011 will decrease rate base in the test years by approximately $10M in 2010 and $30M in 2011. The approximate revenue requirement decrease is approximately $1.4M in 2010 and $4.3M in 2011. The corresponding revenue deficiency impact is a decrease of approximately $1.4M and $3.0M in 2010 and 2011, respectively.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #7 List 1

Interrogatory

Issue 4.2 Are the amounts proposed for 2010/2011 Capital Expenditures appropriate including the specific Sustaining, Development and Operations categories?

Reference: Exhibit D, Tab 1, Schedules 1 to 9

Please identify each component of the capital budget for 2010 and 2011, which is supported by an economic feasibility study and provide the results of each study. Does Hydro One calculate a Profitability Index ("PI") for any of its planned capital spending? If so, please provide the Pis that have been calculated for any component of the 2010 and 2011 capital spending plans.

Response

Hydro One Distribution does not conduct individual economic feasibility studies for capital expenditures and does not calculate a Profitability Index ("PI") as work is not undertaken on the basis of profitability but rather on the basis of business values (e.g. safety, reliability, regulatory), which are discussed on page 3 of Exhibit A, Tab 14, Schedule 6. The individual capital investments described in the schedules of Exhibit D1, Tab 3 are undertaken to address a wide variety of needs including replacing end-of-life equipment, connecting new customers, responding to load growth and system capacity issues, and investing in operating and information system infrastructure. The investments related to these needs are assessed during the Investment Prioritization Process and investments in excess of $1M the needs are documented in the Investment Summary Documents contained in Exhibit D2, Tab 2, Schedule 3.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #8 List 1

Interrogatory

Issue 7.1 Is Hydro One's cost allocation appropriate including the analysis of the relationship between density and cost allocation?

Reference: Exhibit G1, Tab 3, Schedule 1; and Exhibit G1, Tab 4, Schedule 1

Since the amounts being recovered by ratepayers for external funding mechanisms administered by the IESO and the OPA are charged in bills rendered by Hydro One, can ratepayers raise, in these proceedings, questions concerning the classification and allocation between rate classes of the costs being recovered in such external charges and the resulting amount that should be recovered from each rate class for costs being recovered through these external funding mechanisms. If these issues cannot be raised by ratepayers in this proceeding, then in what proceeding can the issues be raised?

Response

The charges applied by Hydro One for IESO and OPA are approved by the OEB. OPA charges based on the Global Adjustment are recovered through the RPP price set by the OEB, or billed to non-RPP customers by Hydro One as Provincial Benefit based on information provided by the IESO. The IESO bills for OPA charges based on the Global Adjustment by way of the Provincial Benefit charge to customers that are market participants. The IESO charges based on their revenue requirement as approved by the OEB and the OPA charges based on their revenue requirement as approved by the OEB, are recovered by way of the Wholesale Market Service charge. Hydro One bills this charge to all non-market participants and the IESO bills this charge to all market participants.

Both charges, Provincial Benefit and Wholesale Market Service charges are volumetric charges and there is no classification and allocation of these charges between customer classes.

Since the OEB approves these charges, it is possible that any concern with respect to these charges may be addressed by the OEB.

However if the question is concerning the mechanisms for collection and delivery of the external funding these mechanisms are being discussed as part of the OEB proceeding (EB-2009-0349) on Rate Protection and Determination of Direct Benefits under Ontario Regulation 330/09 Section 79.1 of the Ontario Energy Board Act issued on September 25, 2009 by the OEB.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #9 List 1

Interrogatory

Issue 7.4 Are the proposed rate impact mitigation plans appropriate and are the resulting customer bil impacts reasonable?

Reference: Exhibit G1, Tab 9, Schedule 1, pages 1 and 2

Hydro One describes an "Alternative" in its evidence, which apparently is acceptable to the customer that held various discussions with Hydro One. Please provide information which will show the impact on that customer of the Alternative described in the evidence compared to the current situation, and clarify whether Hydro One is asking the Board to approve this Alternative.

Response

The alternative approach is to expand the definition of Sub-Transmission customers to include end-use customers at voltages below 13.8kV. This would re-classify the customer from the Forest General Service demand-billed rate class to the Sub-Transmission rate class. Based on the current connectivity of the customer, the HVDS-high, Common Line and LVDS-Low charges would apply. Assuming that the customer is metered on the secondary side of the transformer, and does not own their metering unit, there will be a 44% increase in the total bill. This increase is mainly due to the increase billing kW, from TOU to non-TOU.

Hydro One is not proposing that the Board approve the Alternative. Hydro One is describing the alternative in the pre-filed evidence, as it was presented by the customer to Hydro One. If this Alternative was approved by the OEB and implemented by Hydro One it would result in some customers paying less and some customers paying more than under the currently approved definition for ST customers.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #10 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Throughout Exhibit A, Tab 14, Schedule 2, Hydro One identifies assumptions upon which it bases various aspects of the proposed Green Energy Plan ("Plan"). CME wishes to better understand the basis upon which Hydro One has made the following assumptions:

a) That the revenue requirement associated with a portion of the capital investments contained in the Plan will be recovered through an external funding mechanism that recovers the required revenue from all electricity consumers in Ontario (Exhibit A, Tab 14, Schedule 2, page 2 of 34);

b) That conservation and demand management ("CDM") costs will continue to be externally funded similar to the funding currently provided by the Ontario Power Authority ("OPA") for existing CDM programs (Exhibit A, Tab 14, Schedule 2, pages 2-3 of 34);

c) That Smart Grid investments will be fully funded by Hydro One's customers as they will provide significant benefits to those customers (Exhibit A, Tab 14, Schedule 2, page 3 of 34);

d) That a connection asset investment covers only the work associated with providing isolated devices or other assets required for the specific generators connection to Hydro One's system (Exhibit A, Tab 14, Schedule 2, page 15 of 34); and

e) That expansion of Hydro One's distribution system to connect renewable energy generation includes the following types of investments carried out to serve one or more renewable energy generation facilities (Exhibit A, Tab 14, Schedule 2, page 16 of 34):

(i) Expand or build out the distribution system to the ownership demarcation point of the renewable energy generation facility;

(ii) Rebuilding a single-phase line to three-phase;

(iii) Rebuilding an existing line with a larger size conductor;

(iv) Rebuilding or overbuilding an existing line to provide an additional circuit;

(v) Converting a lower voltage line to operate at higher voltage;

(vi) Replacing a transfer to a larger MVA size;

(vii) Upgrading a voltage regulating transformer or station to a larger MVA size;

(viii) Adding or upgrading capacitor banks to increase system capacity to facilitate the connection of the renewable energy generation facility;

(ix) Building new express feeders to connect renewable energy generation; and

(x) Providing new distribution stations and/or additional capacity at existing distribution stations;

With respect to these assumptions:

a) Please provide a more detailed explanation of Hydro One's basis for making each assumption;

b) Where the assumption is based, in part or in whole, on communications (including power point presentations and emails) between Hydro One and the Ontario

Government, the OPA or the Ontario Energy Board, please provide copies of that communication;

c) These assumptions will have a direct impact on the net costs to be funded by Hydro One customers, and the costs externally funded by all electricity customers in Ontario. CME wishes to better understand what will happen if the Board approves Hydro One's Plan on the basis of these assumptions, and then subsequently some or all of the assumptions turn out to be incorrect. If during the term of the Plan the associated costs are greater than those contained in Exhibit A, Tab 14, Schedule 2, will Hydro One file an Application to increase the rates proposed in this Application? Conversely, if during the term of the Plan the associated costs are less than those contained in Exhibit A, Tab 14, Schedule 2, will Hydro One fie an Application to decrease the rates proposed in this Application?

Response

a)

a – The assumption that a portion of the capital investments will be recovered through an external funding mechanism is in accordance with OReg 330/09 filed on September 9, 2009 and the Boards proceeding (EB-2009-0349) on Rate Protection and Determination of Direct Benefits under Ontario Regulation 330/09.

b – The assumption that CDM costs will continue to be exterbally funded is based on the fact that the costs incurred by distribution companies to deliver CDM programs coordinated by the OPA are currently paid for by the Global Adjustment Mechanism. Bill 150, having received Royal Assent on May 14, 2009, provides authority for the Minister of Energy to issue a directive establishing CDM targets for distributors. Bill 150 stipulates that the IESO shall pay the costs of any programs approved by the Board pursuant to such a directive.

c – Please refer to Exhibit H, Tab 9, Schedule 55.

d – Hydro One's assumptions with respect to the definition of connection cost categories (i.e. Connection, Expansion, Renewable Enabling Investment) are consistent with the proposed DSC amendments issued by the Board on September 11, 2009.

e – See response to part d above.

b) None of the assumptions above are based on communications between Hydro One and the Ontario Government, the OPA or the Ontario Energy Board.

c) Hydro One Distribution does not plan to apply for any change to the rates requested in this Application (EB-2009-0096) over the 2010 and 2011 test year period. Hydro One expects that the Green Energy Plan assumptions beyond the test year period would be revisited as part of Hydro One's next Cost of Service Application.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #11 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: **Exhibit A, Tab 14, Schedule 2, page 1 of 34 and Exhibit A, Tab 14, Schedule 2, page 11 of 34**

Hydro One states that the development of its Plan has been based, in part, on a measured approach to Smart Grid Investment focused on studies, demonstration projects, planning and training. CME wishes to better understand the studies, demonstration projects, planning and training undertaken by Hydro One. CME may wish to review some or all of these studies, demonstration projects, planning and training. Rather than producing all of the studies, demonstration projects, planning and training which have been relied upon by Hydro One in developing the Plan with respect to Smart Grid investment, CME proposes the following staged approach. In response to this interrogatory, please provide a list of all of these documents with a sufficient description to enable Intervenors to determine whether production of the entire document is necessary, and then subsequently allow Intervenors to request production of specific documents, if deemed necessary. If this staged approach is unacceptable to Hydro One, then please produce all of these documents.

Response

The studies, demonstration projects, planning and training are part of the planned investments going forward and have not yet occurred. The "measured approach" to Smart Grid investments refers to the RFP process being used to better define the scope of work, and the staged approach to implementation Hydro One plans to undertake in the Smart Zone, as detailed in the response at Exhibit H, Tab 12, Schedule 46. The information available on total Smart Grid costs is provided in Exhibit H, Tab 9, Schedule 13, while additional details available about specific studies is provided at Exhibit H, Tab 7, Schedule 24, part e).

Canadian Manufacturers & Exporters (CME) INTERROGATORY #12 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: Exhibit A, Tab 14, Schedule 2

The cost of investments contained in the Plan are summarized at a table contained at Exhibit A, Tab 14, Schedule 2 page 1 of 34. These costs, which include both OM&A and Capital are further described in other tables contained at Exhibit A, Tab 14, Schedule 2, pages 14, 15, 19, 23, 24, 28 and 29 of 34. These tables set out the net costs to be funded by Hydro One customers, as well as the costs to be externally funded by generators and externally funded by all electricity consumers in the province. CME seeks to understand the scope of the approvals Hydro One is seeking from the Board in this proceeding. Please confirm whether Hydro One is seeking Board approval of only the net costs to be funded by the rates proposed in this Application, or alternatively, is Hydro One is also asking the Board to conduct the Calculation of Rate Protection prescribed by section 3 of Ontario Regulation 330/09? If the Board is not being asked to conduct the Calculation of Rate Protection in this proceeding, then in what forum would Hydro One expect the Calculation of Rate Protection to occur?

Response

Hydro One is seeking approval for all the work included in this application. In addition, Hydro One is seeking approval of the 'net' costs (net of amounts collected via an external funding mechanism) to be included in its Distribution Revenue Requirement and rates. Hydro One has identified the additional revenue requirement, it submits, will need to be collected via an external funding mechanism for work to be completed by Hydro One Distribution that benefits all electricity customers in the province.

It is not clear to Hydro One what the process will be for recovering the additional revenue requirement to be collected from all electricity customers in the province via an external funding mechanism in accordance with OReg 330/09. Hydro One seeks guidance from the Board on this issue.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #13 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: Exhibit A, Tab 14, Schedule 2, page 3 of 34

Hydro One has assumed that Smart Grid Investments will be fully funded by Hydro One's distribution customers as they will provide significant benefits to Hydro One's distribution customers. Please summarize all of the benefits which Hydro One believes the Smart Grid Investments will provide to Hydro One's distribution customers;

Response

Please refer to the Smart Grid RFP information in Exhibit H, Tab 12, Schedule 46 under the “Expected Benefits” section.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #14 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: Exhibit A, Tab 14, Schedule 2, page 7 of 34 and Exhibit A, Tab 14, Schedule 2, page 13 of 34

Hydro One projects that as much as 3,500 MW of renewable energy generation could seek connection by 2011, and an additional 3,500 MW could seek connection by 2014. CME wishes to obtain further information about this forecast.

a) Is Hydro One's estimate of 3,500 MW seeking connection in 2011, with an additional 3,500 MW seeking connection by 2014 the maximum amount of renewable energy generation that could seek connection in those years? If not, what is the maximum amount of renewable energy generation connection that Hydro One could anticipate being sought during these two time periods.

b) Please confirm that Hydro One's distribution cost estimates are based on the connection of 3,500 MW of renewable energy generation seeking connection in 2011, and another 3,500 MW seeking connection by 2014. If not, what are the estimates used for Hydro One's cost estimates.

c) If the cost estimates are based on 3,500 MW of renewable energy generation seeking connection in 2011, and another 3,500 MW seeking connection by 2014, then what would be the cost consequences be, if any, of less than 3,500 MW seeking connection in these time periods? Conversely, what would the cost consequences be, if any, if more than 3,500 MW of renewable energy generation seeks connection in these time periods?

Response

a) Hydro One believes that the forecast (3,500MW by 2011 and an additional 3,500MW by 2014) is appropriate and does not expect the actual figures will deviate much from the forecast.

b) Yes. Hydro One's distribution cost estimates are based on the connection of 3,500 MW of renewable energy generation seeking connection in 2011, and another 3,500 MW seeking connection by 2014.

c) Hydro One believes that its forecast cost to connect renewable energy generation is appropriate at this time. Hydro One assumes the risks associated with a change in the costs included in its rate base for connecting higher or lower amounts of renewable energy generation connection in the test year period.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #15 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: Exhibit A, Tab 14, Schedule 2, page 14 of 34

Hydro One sets out that the development of OM&A expenditures related to renewable energy generation is $3M in 2010, $3M in 2011, and $10M in 2012 to 2014. Hydro One further states that if these OM&A costs are determined to have increased to material levels at some point in the future, Hydro One will seek approval to include them as part of the revenue requirement to be external funded. In this context, if these OM&A costs do not materialize in the future, will Hydro One seek approval to reduce the revenue requirement approved in this Application?

Response

Hydro One bears the risk if the costs are higher or lower than planned/approved. In this case Hydro One has noted that there is a chance that the costs will be materially higher than planned. In addition, Hydro One believes that if additional costs were incurred it would most likely be for the benefit of all electricity customers of the province and therefore the appropriate treatment would be collection through the externally funded mechanism.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #15 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: Exhibit A, Tab 14, Schedule 2, pages 28 to 30 of 34

Hydro One sets out its capital investment for development of the Smart Grid centered around the "Smart Zone" pilot site in Owen Sound. CME wishes to better understand the level of coordination between LDCs in Ontario and the Ontario Government in the development of the Ontario Smart Grid. To what extent has Hydro One worked in conjunction with other Ontario LDCs and the Ontario Government in determining how to develop its Smart Grid, including the creation of a wide area network, the rolling out of enablers such as Wimax and geographical information systems ("GIS"), intelligent electronic devices, mobile workforce tools, outage management systems, distribution monitoring and automation, SCADA, customer demand response, in-home conservation tools, energy storage, operating procedures and training manuals? Please provide copies of communications (including emails and power point presentations) between Hydro One and other Ontario LDCs and/or the Ontario Government on these Smart Grid issues.

Response

The green energy plan is relatively new, however Hydro One has participated in Ontario based studies on smart grid seeking to collaborate on need and develop a roadmap for the province.

The report provide as Attachment 1 is a prime example from the Ontario Smart Grid Forum which included representatives from across the electrical industry in Ontario including LDCs and government.

As a result of the above collaboration and the direction from the GEGEA, Hydro One has begun development of its own strategy and process to elaborate further on smart grid requirements. Much of the information in Attachments 2 and 3 has been shared with other LDCs in the province and the Government to provide a view of the steps Hydro One intends to undertake to further develop its smart grid initiative. This information has also been broadly shared with over 70 industry vendors to seek input on the strategy we are proposing with positive feedback.

Attachment 2 makes reference to 1.8Ghz spectrum for use for electrical critical infrastructure protection. Through collaboration with other provincial utilities and other international industry stakeholders Hydro One was able to secure a policy and spectrum plan change from Industry Canada. The following link provides a reference to the Industry Canada announcement and as well other documentation can be located on their web site.

http://www.ic.gc.ca/epic/site/smt-gst.nsf/en/sf09015e.html

This spectrum is planned for use for Smart Meter communications back haul and potentially to satisfy the communication requirements for distributed generators. Hydro One has not been as active with provincial LDCs in this area since this requirement for private backhaul is somewhat unique to rural providers where third party carrier services are not ubiquitous.

Hydro One is unique in terms of our demographics in the province (scale / rural line density / customer classes) as well as the immediate urgency for scalable solutions to manage large number of distributed generators safely and effectively. As a result, our findings may be different than other LDCs. Nevertheless Hydro One expects to further collaborate with LDCs and Government on our findings coming from our Smart Grid RFP and resulting Smart Zone initiative.

Enabling Tomorrow's Electricity System

Report of the Ontario Smart Grid Forum

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The Forum gratefully acknowledges the contribution of Joel Singer, of Singer & Watts, Forum Facilitator and Principal Author.

Executive Summary

THE SMART GRID



Source: European Technology Platform SmartGrids

The use and production of electricity are changing. Consumers are becoming more aware of the environmental impacts of the electricity system and are seeking greater ability to manage their electricity use to control costs and help improve the environment. New dispersed energy resources such as solar, wind and storage hold the promise of not only lowering greenhouse gases, but also allowing consumers to produce their own electricity and sell the excess. Widespread use of plug-in electric vehicles will bring even greater change as consumers look to conveniently charge their cars at home or on the road.

These changes will require a paradigm shift in the electricity system. Today, the grid is primarily a vehicle for moving electricity from generators to consumers. Tomorrow, the grid will enable two-way flows of electricity and information as new technologies make possible new forms of electricity production, delivery and use. The smart grid is the name given to the new electricity system that will emerge from this paradigm shift.

A smart grid is a modern electric system. It uses sensors, monitoring, communications, automation and computers to improve the flexibility, security, reliability, efficiency, and safety of the electricity system. It increases consumer choice by allowing consumers to better control their electricity use in response to prices or other parameters. A smart grid includes diverse and distributed energy resources and accommodates electric vehicle charging. In short, it brings all elements of the electricity system – production, delivery and consumption – closer together to improve overall system operation for the benefit of consumers and the environment.

Over the past few years, Ontario has undertaken bold initiatives that both underscore the need for a smart grid and help move us toward it. To reduce the environmental footprint of the electricity sector, the Province has:

- Required the shut-down of Ontario's coal-fired generation;
- Worked to create a culture of conservation; and
- Procured renewable generation sources to meet future electricity needs.

These initiatives require the electricity system to accommodate new types of generation in new locations including variable generation sources whose output depends on the wind and sun. The system must also promote increased consumer involvement in electricity consumption decisions and incorporate two-way power flows on lines that have historically been used for delivery alone.

Ontario's leadership in smart meters represents an essential first step in realizing the benefits of a smart grid for consumers. By measuring hourly electricity consumption, these meters allow the provision of prices that vary with time-of-use. Research has shown that providing transparent electricity prices to consumers together with time-of-use rates can lead to consumption reductions that range from five to fifteen per cent. The completion of smart meter installation and implementation of time-of-use rates, along with the information necessary to educate consumers about these changes, will let consumers benefit from in-home energy displays, home energy management systems and related services. These devices and services will help households and small businesses to better manage their electricity use in response to prices or other parameters.

Provincial initiatives on conservation, renewable generation and smart meters begin the move towards a new electricity system, but their full promise will not be realized without the advanced technologies that make the smart grid possible. The challenges that Ontario faces in simultaneously incorporating distributed generation, addressing growth, and replacing aging infrastructure while maintaining reliability and quality of service are daunting. While new grid infrastructure will be necessary to connect generation resources, replace aging assets and address growth, simply adding wires and equipment without intelligence is not a viable option.

While promising, smart grid technologies are not risk free. Many of these technologies are in the early stages of development. Not all of them will advance to commercialization and for some, the cost of implementation on a commercial scale may prove prohibitive. Finally, the challenge of interoperability, enabling new and existing technologies to exchange information and work together is substantial. Overcoming these challenges will require innovation, investment, creativity and hard work, but if Ontario is to realize a sustainable future and continue to grow and prosper, the transformation of its electricity infrastructure is essential. Clearly defining the roles and opportunities for all the potential market players will create an environment that encourages the investment necessary to support this transformation.

Ontario is well positioned to develop smart grid technologies and systems. The Ontario Centres of Excellence (OCE) currently has 14 projects underway or in the pipeline that relate to smart grids. All are collaboratively supported by industrial partners, academic institutions and OCE. The total investment in these projects is currently close to $12 million with almost half of this amount coming from OCE. Sustained funding for research and development is essential if Ontario is to realize the potential benefits from developing and commercializing smart grid applications.

The potential of smart grid technologies will only be realized if they are operated by skilled employees and feed into processes designed to take full advantage of the new technologies. Ontario must continue to educate and train employees who are capable of designing, developing and operating the smart grid. Together, technology, people and processes will permit the realization of a modern electricity system that benefits all Ontarians.

SUMMARY OF THE FORUM'S WORK

This report presents the work of the Ontario Smart Grid Forum (Forum), a group of industry leaders who came together over a seven-month period to learn more about the smart grid, its benefits for consumers, and to develop recommendations for advancing it in Ontario. The Forum did not undertake to analyze in detail the cost of moving to a smart grid or to specify technology requirements as these matters will depend on the investment decisions of individuals and companies, and should be considered in the context of those decisions.

The Forum heard from invited experts on various aspects of the smart grid and then discussed the implications of their presentations for Ontario. The presentations covered the following topics.

- **Smart Grid Vision:** The Forum heard overview presentations describing the vision of a smart grid and smart grid activities in the United States and the European Union. In both jurisdictions, ongoing efforts are underway to establish the technical, legal and institutional frameworks necessary for smart grids to develop. This information helped Forum members to better understand the components and benefits of a smart grid and to develop a vision for an Ontario smart grid.
- **Consumers:** Smart grid technologies, particularly home energy management systems, will change how consumers use electricity by increasing their ability to control household appliances and equipment and thereby manage their electricity cost and contribute to a better environment. Some of these devices can also integrate production from renewable technologies like rooftop solar photovoltaics. A smart grid can change how consumers, utilities, retailers and other service providers interact by offering new ways for them to communicate and expanding the types of service available to consumers. Smart grid technologies will also enable many different types of companies outside the utility sphere to enter the market for home energy management systems and services to help spur innovation.
- **Ontario Status:** Ontario distributors, transmitters and the Independent Electricity System Operator (IESO) are currently undertaking smart grid-related activities, mostly involving the ongoing implementation of smart meters and associated technology. These companies are also developing or exploring smart grid activities beyond smart metering. Examples of these activities include ongoing efforts to increase available communications options and promote the creation of a communications spectrum for use by electric utilities; projects to install distribution transformer monitors and related communications equipment; and increased installation of automated distribution equipment.

The Forum's working group surveyed 12 of Ontario's largest distribution utilities, serving about 78 per cent of the province's customers about their current investments and future investment plans related to a smart grid. This research confirmed that in addition to smart meter deployment and advanced metering infrastructure, distributors are incorporating other smart grid technologies into both current and future investment plans, but not on a comprehensive basis. The research concluded that over the next five years, currently planned investments by the distributors surveyed are insufficient to allow for full smart grid deployment.[1]

- **Distribution:** The use of advanced sensing, automation and communications equipment on the distribution system can improve reliability, equipment performance, restoration times and power quality. This technology also can be used to improve distribution system maintenance and operations, and enhance system planning. The Electricity Distributors Association presented its vision for electricity distributors, which sees them using advanced technology to optimize the operation of their distribution systems and enhance their ability to provide a variety of energy services, including conservation and demand management, and distributed generation, in support of provincial energy policy and community energy plans.

- **Distributed Energy Resources:** Energy resources on the distribution system include generation, storage and demand response. Ontario is in the process of incorporating substantial amounts of renewable generation. Connecting this generation to distribution lines that were designed and built to deliver electricity to consumers poses substantial challenges. Smart grid technology can help maximize the amount of generation that can be connected to the distribution system while maintaining safety and service quality to consumers.

  Energy storage offers many potential benefits such as:

  - delivering energy to meet peak load;
  - providing ancillary services, including regulation and voltage support;
  - allowing for the deferral of distribution investments; and
  - helping to integrate variable generation such as solar and wind, and maximize the value of the energy produced by these technologies.

  While storage can produce many benefits, storage projects can be difficult to fund because the benefits produced typically flow to multiple parties. The returns to the entity investing in the storage facility may be insufficient to justify the investment.

  Demand response is the ability of customers to change their consumption in response to price or other signals. While demand response is currently focused on reducing consumption during peak periods, it is easy to envision future circumstances where demand response also will be used to help balance the variable production of wind and solar generation. Smart grid technologies facilitate demand response by giving customers the ability to see prices and the tools to react to them.

[1] Current Status and Investments Plans: David Curtis, Hydro One; John Mulrooney, PowerStream; Joshua Wong, Toronto Hydro: http://www.ieso.ca/imoweb/pubs/smart_grid/Current_Status_and_Investment_Plans.pdf

- **Micro-Grids:** A micro-grid is envisioned as an integrated solution that meets the energy needs of a group of consumers, such as a neighbourhood or a town, or a single consumer, such as a university. Research is required to address questions regarding the costs and benefits of micro-grids and the appropriate role for them in Ontario.

- **Electric Vehicles:** Plug-in electric vehicles offer the prospect of reduced emissions and lower cost. Their widespread adoption, however, will present challenges and opportunities for the electricity system. At a local level, the major challenge involves enabling vehicles to be charged safely and conveniently without adversely impacting local distribution equipment. For the electricity system as a whole, the challenges involve finding ways to move vehicle charging into off-peak periods so as to avoid increasing peak load and the resulting need for additional peaking resources. The opportunity involves using the energy stored in vehicle batteries to provide peak period energy. A smart grid is essential if Ontario is to address the challenges and embrace the opportunities presented by plug-in electric vehicles.

- **Standards and Security:** Standards and security are vital if the smart grid is to develop efficiently over time. Standards are required to allow devices developed by different companies for different purposes to interact. The notion of interoperability takes the concept further to cover the ability of various devices to actually work together to perform the functions for which they were designed.

  Security is crucial because grid modernization requires installing large numbers of devices that must communicate back into essential computer systems covering core utility functions such as operations, outage management and billing. Many smart grid devices are deployed in physically unsecured locations and thus can be accessed by those seeking to penetrate critical utility systems. Beyond the challenges it poses for cyber security, the smart grid may enhance physical security at substations and other facilities by facilitating remote monitoring via cameras and sensors.

- **Transmission:** Historically the large volume of electricity carried by transmission lines and their relatively small number have justified more extensive monitoring and more automated control of the transmission system in serving large generators and consumers, including distributors. The need to incorporate substantial quantities of variable generation and the development of storage will drive increased application of advanced technologies. Transmission can become smarter through the installation of additional monitoring to allow better assessment of conditions on interconnected systems and through the use of technologies that enhance control of electricity flows over transmission lines.

KEY RECOMMENDATIONS

Presented below are some of the key recommendations that follow in the Forum's Report. They reflect the central belief that Ontario should develop a smart grid to improve the prosperity of its citizens, the performance of its electricity system and the environment. The rapid development of a smart grid to benefit electricity consumers and advance environmental initiatives should be the policy of the Province of Ontario.

- The Ministry of Energy and Infrastructure should facilitate the development of Ontario's smart grid through legislation, regulation or other available means that clarify authorities, establish requirements or create incentives for those entities investing in Ontario's electricity system to accelerate the deployment or enhance the functioning of smart grid technologies.
- Consumers and their designated representatives should have access to timely information on their consumption and the price they are being charged from a smart meter with two-way communication capability or via the internet. Consumers should pay prices that reflect the cost of energy at different times.
- In order to plan and operate the grid reliably and efficiently, distributors, transmitters, the Ontario Energy Board (OEB), Ontario Power Authority (OPA) and the IESO should work together to:
  - develop requirements for and propose sufficient monitoring of distribution connected generation, energy storage, and responsive load;
  - determine the authority necessary to direct the operation of these facilities, the conditions under which their operation could be directed and any compensation that would be provided to the facility;
  - propose contractual and pricing arrangements with distribution connected generation, energy storage, and responsive load that support efficient grid operations and are consistent with the operation of the wholesale electricity market;
  - coordinate the development and implementation of grid control and information systems to facilitate the actions listed above.
- A Task Force led by the Ministry of Economic Development and involving other relevant Ministries should be created consisting of representatives from the auto sector (vehicle manufacturers and suppliers) electricity sector (OEB, IESO, OPA, distributors and generators) and universities to develop a comprehensive plan for enabling plug-in electric vehicles in Ontario. The plan would address policy, financial, and electricity system impacts of substantial electric vehicle penetration and identify what is required to ensure that vehicles can be charged as they develop. The Task Force should link to the ongoing collaborative work by the Electric Power Research Institute (EPRI), the Society of Automotive Engineers (SAE) and standards development organizations to develop electric vehicles standards.
- Utilities, the IESO, the OPA, universities and OCE should conduct research and development related to smart grids to advance Ontario's leadership position in this area, promote innovation and develop green jobs in the province. The OCE should facilitate the development of a task force to produce a framework for smart grid research in Ontario that would include targeted amounts of funding and proposed funding mechanisms.

CONCLUSIONS AND NEXT STEPS

From this diverse body of materials a few common themes emerged. There is tremendous excitement about the potential of the smart grid to provide economic benefits and an improved environment. Balancing this excitement is a recognition that not all smart grid technologies will deliver as promised. Inevitably, there will be false starts and dead ends. Open standards and integrated approaches are the key to minimizing the risk of stranded technologies.

Coordination on several different levels will be a key factor in the successful development of a smart grid. On the technological level, there is the need for standards and interoperatibility to allow devices developed by multiple suppliers to communicate and work together. Coordinated development across the divisions of the electricity system (i.e. customers, distribution, retail service providers, transmission and generation) also will be essential for the smart grid to function as an integrated whole. To deliver on its promise, the smart grid must enable the transparent exchange of operating and price information to efficiently link customer choices with the dispatch of resources and the operation of the electricity grid.

Better coordination will also be required between the electricity industry and other industries. Electric vehicles are a particularly good example of this type of linkage. Vehicle manufactures and the electricity industry must work together to ensure that electric cars can be charged conveniently in multiple locations and that vehicle charging can be accommodated without adversely impacting electric service.

Presentations that described smart grid efforts in Europe and the United States showed that both these jurisdictions are aggressively pursuing smart grid development. While one jurisdiction may be more advanced in adopting certain technologies, overall there is no clear leader in smart grid development. Instead, there is a universal sense of tremendous energy and enthusiasm for modernizing the electricity system to benefit consumers and the environment through improved grid operations and the incorporation of renewable generation. In terms of how to marshal this energy to transform the electricity system, however, the presentations contained more questions than answers. Ontario, like the other jurisdictions, has the opportunity to both lead and learn from the efforts of others as it works to create a smart grid.

The Forum sees value in continuing to champion smart grid progress, monitor ongoing developments and advocate common approaches where they make sense. To this end, the Forum believes that an enduring organization to promote smart grid development with a broader base of representation may be appropriate in the future. The Forum will consider this further based on insights gathered from discussions with Government and industry following the release of this Report.

AN OPPORTUNITY FOR INNOVATION

Ongoing initiatives, growing consumer interest, new technologies, articulated policy direction and economic pressures to increase efficiency and performance are all converging to create an unprecedented opportunity for bold initiatives in Ontario to realize the potential offered by a smart grid. Ontario should seize the chance to become a leader in developing and deploying smart grid technologies to benefit its citizens and enhance its economy. In the pages that follow, Ontario's Smart Grid Forum discusses in detail the opportunities that a smart grid presents and recommends actions to realize them.

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President and CEO,
Independent Electricity System Operator
Chair, Ontario Smart Grid Forum



Michael Angemeer
President and CEO, Veridian Corporation



David Collie
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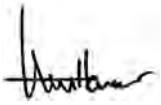

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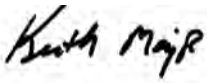

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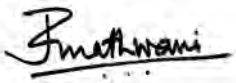

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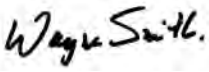

Wayne Smith
Vice President – Grid Operations, Hydro One

In addition to the members signing above, the Ontario Smart Grid Forum included representation from the Ministry of Energy and Infrastructure and the Ontario Energy Board. These representatives participated in Forum discussions, but they were not participants in the consensus and are not responsible for the recommendations of the Forum. The Forum wishes to acknowledge and thank the following representatives for their contributions:

Aleck Dadson
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Annamaria Cross
Senior Manager, Office of Consumer and Regulatory Affairs
Ministry of Energy and Infrastructure

Rosalyn Lawrence*
Assistant Deputy Minister, Consumer and Regulatory Affairs Division
Ministry of Energy and Infrastructure

Peter Wallace*
Deputy Minister – Ministry of Energy and Infrastructure

* Titles listed were appropriate prior to the final release of the report

Introduction

This document presents the work of the Ontario Smart Grid Forum. The report begins by describing the Forum, what it set out to accomplish, and how it operated. A vision of the smart grid follows which explains the smart grid and the fundamental transformation of the electricity system that it represents. Subsequent sections discuss various aspects of smart grid development and make recommendations in each area. The report concludes with a section on advancing the smart grid.

ONTARIO SMART GRID FORUM

The Forum was convened by Ontario's IESO in collaboration with Burlington Hydro, Hydro One, Hydro Ottawa and Toronto Hydro for the purpose of bringing industry leaders together to learn about the smart grid, explore its potential benefits for Ontario, and recommend appropriate actions to policymakers and the industry at large that will promote smart grid development.[2] Over the period from June through December 2008, the Forum heard experts from Ontario and around the world present on various aspects of the smart grid and engaged in far ranging discussions on these topics. A list of the presentations to the Forum and a link to them can be found in Appendix A.

In the process of developing this report, the Forum reflected on what it had heard from the various presenters and the implications of this information for Ontario. The Forum operated by consensus and the recommendations presented in this report are endorsed by all of the signatories to this document.

The Forum also formed the Ontario Smart Grid Working Group (Working Group) to support its work and undertake research. The Working Group helped the presenters to focus their presentations, investigated specific topics, provided more detailed background on the smart grid and contributed to the Forum's discussions. The Working Group produced a number of research papers, which are referenced in Appendix A.

- Consumer Positions and Attitudes about Electricity
- Value Proposition for a Smart Grid
- Distributor Smart Grid Investments – Current Status and Investment Plans
- Survey of Smart Grid Technologies

[2] Ontario Smart Grid Forum Terms of Reference: http://www.ieso.ca/imoweb/pubs/smart_grid/TOR-SGF.pdf

ACKNOWLEDGEMENTS

The Forum wishes to acknowledge the assistance it received in completing its work. All the individuals who presented, as listed in Appendix A, gave generously of their time and expertise. The Forum wishes to thank them sincerely for their help and willingness to share their knowledge.

The support provided by the Working Group contributed significantly to the work of the Forum. Their efforts are appreciated. The Working Group consisted of:

Raed Abdullah
Hydro Ottawa Limited

David Curtis
Hydro One Networks Inc.

Lisa Dignard-Bailey, Ph.D
Natural Resources Canada

John Mulrooney
PowerStream Inc.

Joshua Wong
Toronto Hydro Electric System Ltd.

The Forum also could not have completed its work without the efforts of certain key individuals. We wish to thank the following people for their contributions. Don Tench of the IESO served as the key liaison with the Forum members, chaired the Working Group and contributed his knowledge, creativity and enthusiasm to the Forum's discussions. Derek Beamer of the IESO located expert presenters, worked with them to shape their presentations and kept the Forum on track and on schedule. Melinda Rankin of the IESO provided administrative support to Derek and Don, and the Forum as a whole.

Smart Grid Vision

Smart grid is the term applied to tomorrow's electricity system. It encompasses a variety of changes that will transform the way electricity is used, delivered and produced, and result in a cleaner more efficient and more interactive electricity system. It represents a paradigm shift for electricity much in the way that cell phones transformed communications. The concept is broad; it stretches beyond modernization of the transmission and distribution grid to include devices that allow consumers to better manage their electricity use, new ways of creating and storing electricity, and the widespread adoption of electric vehicles.

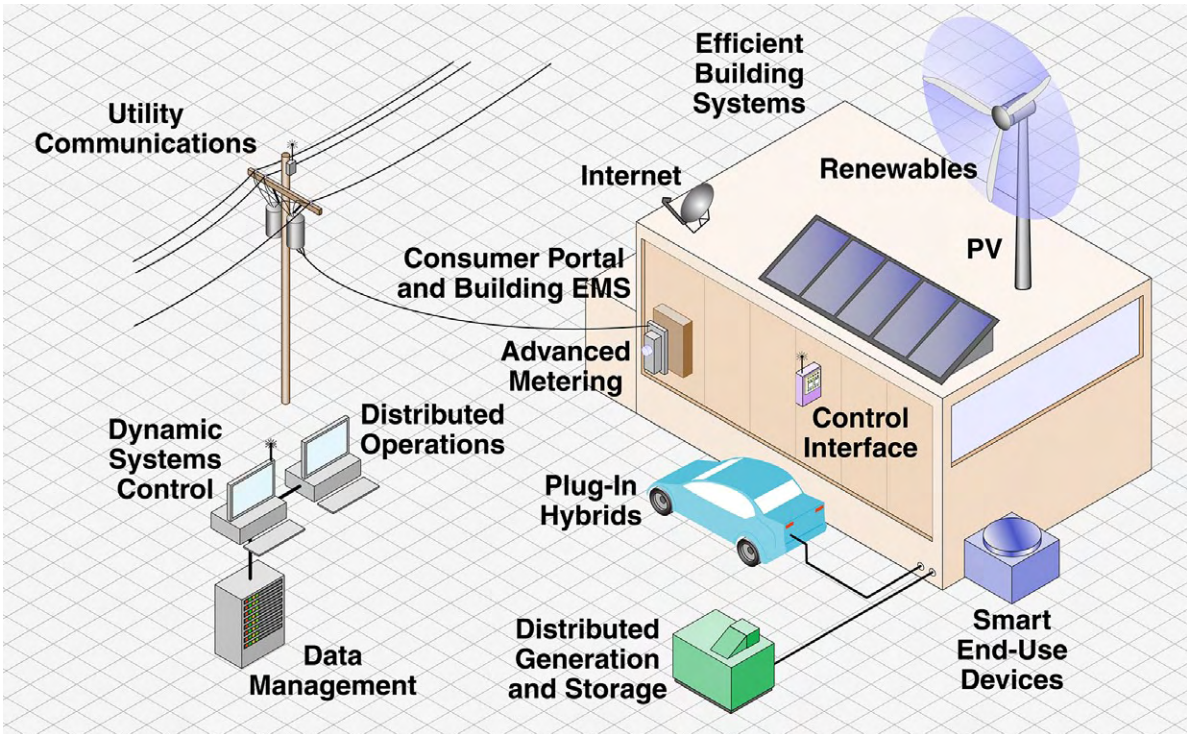
Ontario's move to a culture of conservation and its substantial commitment to renewable energy will also be supported by the smart grid. Smart meters, a major smart grid component, can give consumers timely information on price and consumption. Emerging devices will empower consumers to act on this information automatically while at the same time improving their energy efficiency, comfort and convenience. New sensing, monitoring, protection and control technologies will enhance the ability of the grid to incorporate renewable generation.

The institutional structure of the electricity industry makes it easy to look at how the smart grid will impact each piece of the system in isolation, but the most profound impact of a smart grid may be its ability to link these pieces more closely together. In Ontario we have numerous distribution utilities, one large transmission company and a few smaller ones; one large generating company and many smaller ones. The province has a system/market operator and a corporation responsible for longer-term system planning, and procuring electricity supply and demand resources. While the smart grid will affect each of these segments in different ways, it will affect all of them by increasing their ability to work together to better serve consumers.

SMART GRID DEFINITION

A smart grid is a modern electric system. It uses communications, sensors, automation and computers to improve the flexibility, security, reliability, efficiency, and safety of the electricity system. It offers consumers increased choice by facilitating opportunities to control their electricity use and respond to electricity price changes by adjusting their consumption. A smart grid includes diverse and dispersed energy resources and accommodates electric vehicle charging. It facilitates connection and integrated operation. In short, it brings all elements of the electricity system – production, delivery and consumption closer together to improve overall system operation for the benefit of consumers and the environment.

A smart grid is not only information rich, but also has the analytic infrastructure, processes and trained individuals necessary to integrate and act on information in the very short time frames required by the electricity system. It is characterized by clear standards, security protection and open architecture that allow for continued innovation through the development and deployment of new technologies and applications by multiple suppliers.



Source: Electric Power Research Institute

DRIVERS FOR A SMART GRID

The Province's commitment to establishing a culture of conservation and the desire to reduce the environmental footprint of the electricity sector are major drivers for creating a modern grid. The culture of conservation requires the continual search for new ways to encourage all Ontarians to use energy more efficiently and lower consumption during peak periods. The comprehensive provision of smart meters creates the opportunity for all Ontarians to better understand and manage their electricity usage and, for those who wish, to become active providers of demand response.

The prominence of renewable energy in Ontario's resource portfolio requires an increased ability to accommodate variable generation from wind and solar. Where today the grid serves primarily as a vehicle to move electricity generated in large central facilities to consumers, in the very near future, the grid will need to do much more. As the number and distribution of smaller generators grows, the operational challenge of incorporating these energy resources, while maintaining safety and reliability, will also grow. Meeting this challenge will require a smart grid.

Other features of Ontario also drive development of a smart grid. Like most jurisdictions in North America that saw substantial growth after World War II, Ontario is facing the need to replace a significant amount of its electricity infrastructure. This need creates an opportunity to use smart grid technology both to maximize the use of existing equipment and to improve the efficiency of the grid as it is replaced. Growth and redevelopment also present opportunities to introduce smart grid technologies in newly developed and reconstructed areas. Demands by industry and consumers for increased reliability and power quality technology are also pushing toward a smarter grid.

PROMISE, COST AND TIMING OF A SMART GRID

The Forum's research has uncovered many potential benefits from a smart grid in the areas of economics, environment and operating performance. The ability of consumers to increasingly participate in the electricity market by adjusting their demand in response to price or other signals will help to defer the need for peaking resources and incorporate additional generation from variable sources. Improved system economics will come from reduced losses during electricity delivery (line losses) and better use of station equipment. Potential reductions in congestion will also allow greater use of the most cost effective generation and improve the capacity to move generation throughout the province. Greater ability to integrate generation and load can also reduce the cost of operating reserve and some ancillary services. Finally, improved analytics and the ability for the grid to automatically restore itself from faults can reduce the scope and duration of outages, lower operations and maintenance costs, and improve service to customers.

Many of the identified economic benefits also have associated environmental benefits. Reduced losses not only reduce cost, they allow more of the electricity generated to reach consumers thereby lowering the environmental impacts from generation. Increased ability to incorporate distributed energy resources, including both renewable generation and demand response, will allow Ontario to move more quickly to a cleaner resource mix. Using existing assets more efficiently can defer the need to expand the grid to accommodate growth.

The smart grid offers enhanced operational performance. Greater awareness of system conditions can help anticipate and address problems before they lead to outages, minimize the scope of outages that do occur, and enable more rapid restoration of power. With a smart grid, these fixes may increasingly occur

automatically so that the grid becomes self healing.[3] The ability to remotely monitor equipment condition and performance can also enhance security, help better target maintenance and improve the accuracy of replacement decisions. The information provided by a smart grid also can be used to improve power quality, which is increasingly important in operating today's sophisticated equipment controlled by digital electronics.

By automating functions that are controlled manually today, the smart grid will increase productivity, which will be essential in managing the more complex grid of tomorrow and helpful in addressing the demographic issues facing the electric system as the baby boomers retire and new workers need to be hired and trained. Finally, the smart grid can provide significant operational advantages through its ability to improve both public and worker safety by increasing the amount of system information available for protection and control and by enabling remote operation and automation of equipment.

The costs of the smart grid are difficult to quantify. They will depend on investment decisions and the pace of implementation by numerous companies and individuals undertaking smart grid expenditures. It is through the analysis underlying these decisions that the benefits and costs of specific smart grid investments will be evaluated. Certain cost elements that support the smart grid have already been incurred. Ontario's investment in smart meters and advanced metering infrastructure provide an important connection with customers and the beginning of the communications infrastructure necessary for a smart grid. Additional communications, with greater bandwidth, speed and reliability will be needed, for full smart grid implementation. Moreover, much of the distribution infrastructure replaced over the last few years is already smart grid compatible.

Preliminary cost projections prepared by Forum members and extrapolated to cover Ontario's entire grid sector (distribution, transmission and the IESO) estimate that incremental annual capital spending on a smart grid would average about $320 million over the initial five years.[4]

This investment, which is in addition to the spending currently planned on smart meters, grid expansion to incorporate generation and grid refurbishment, would only occur based on a clear Provincial commitment to smart grid implementation with supporting legislation and regulations. Customer support also would be a key factor in evaluating smart grid investment and customer education would be necessary to inform consumers on this issue. Investment at this level would require increased availability of demonstrated smart grid technology and the human resources to install and integrate it. Finally, the costs and benefits of proposed incremental smart grid investments would be evaluated through appropriate regulatory processes.

The timing of smart grid development also will depend on individual investment decisions, which in turn will be influenced by external policy drivers. The investment plans by grid owners, operators and consumers that will largely determine the pace of adoption for smart grid technologies will be based on their individual needs and circumstances, and their available capital. Government policy, implemented through incentives, mandates or regulatory initiatives will be a major factor in influencing the timing of investments.

In short, because the smart grid is not a single project, but rather a series of actions by a variety of entities to modernize the electricity system, it is difficult to produce a definitive timeline for smart grid development. Instead, the paragraphs below set out some likely features of smart grid development in

[3] Characteristics of a Modern Grid: U.S. National Energy Technology Laboratory: http://www.netl.doe.gov/moderngrid/docs/Self%20Heals_Final_v2_0.pdf?7982b8d0

[4] Comparisons between this estimate and the smart grid spending estimates for other jurisdictions are not meaningful because of the different spending categories included in various figures and the different starting point for each jurisdiction. For example, the above cost estimate does not include the cost of renewable energy resources or any smart meter costs.

different time periods based on current issues and anticipated developments. They are predicated on Provincial support for smart grid development, continued advances in technology, and the workforce training and process development necessary to use this technology effectively.

By 2011, the most visible elements of smart grid deployment will be the completion of smart meter installation and the introduction of residential time-of-use rates with the customer communications necessary to support them. Time-of-use rates should lead consumers to begin installing simple in-home energy displays showing prices and consumption. Utilities will be demonstrating smart grid technologies in operations and planning. Additional work to demonstrate the use of smart grid technologies to help integrate distributed energy resources will be underway. Work should also be ongoing regarding the incorporation of plug-in electric vehicles into the grid.

By 2015, consumers will have had several years of experience with time-of-use rates and the penetration of home energy management systems and smart appliances to control energy use is expected to increase substantially, particularly if there are programs that promote their installation. Results from utility demonstration projects should be widely available, leading to decisions on greater deployment of feeder and substation automation technologies. This deployment is likely to focus initially on new construction, areas undergoing significant refurbishment, and locations with load growth or reliability issues that are amenable to smart grid solutions. Utilities should also be engaged in the process of enterprise integration so that the information produced by the smart grid can be used effectively in operations, planning and customer service. Ontario will be well on its way to incorporating the substantial amounts of renewable generation currently anticipated in its supply mix. Projects involving the use of storage and demand response to address variability in renewable production should also be underway. Coordination among the various divisions of the electricity system should be enhanced to take full advantage of available information across the entire system. The penetration of plug-in electric vehicles should be accelerating and the infrastructure necessary to incorporate safe and convenient charging and reliable billing should be largely in place.

By 2020, smart appliances and other equipment, and home energy management systems should be standard in new installations and for replacement purchases. For utilities, build-out of the smart grid should be accelerating as significant retrofit of existing equipment will allow them to maximize value of the investments they will have already made in communications, computers systems and enterprise integration. Micro-grids may begin to emerge in niche applications. Coordination across the sector should be fully addressed. Plug-in electric vehicle sales should be substantial with convenient charging and billing readily available. New technologies and approaches, as yet undeveloped, are likely to be the focus of smart grid activities.

OVERALL RECOMMENDATION

This recommendation reflects the Forum's central belief that Ontario should develop a smart grid to improve the prosperity of its citizens, the performance of its electricity system and the environment. The rapid development of a smart grid to benefit electricity consumers and further environmental initiatives should be the policy of the Province of Ontario.

- The Ministry of Energy and Infrastructure should facilitate the development of Ontario's smart grid through legislation, regulation or other available means that clarify authorities, establish requirements or create incentives for those entities investing in Ontario's electricity system to accelerate the deployment or enhance the functioning of smart grid technologies.

Consumer Technologies

INTRODUCTION

While all aspects of smart grid development will ultimately impact consumers, this section discusses smart grid technologies that directly touch residential and small business consumers. The Forum believes that a smart grid must enable devices that will allow these consumers to gain greater control over their electricity usage to lower costs, improve convenience and support growing environmental awareness. A smart grid must also facilitate consumer installation of small-scale self-generation through renewable technologies and help them sell any excess generation back to the grid.



OPPORTUNITIES AND BARRIERS

The Forum received several presentations showing various conceptions of how residential consumers will manage their electric equipment and thus their electricity use in the near future using home energy management systems.[5] These in-home devices already exist, but are not yet widely deployed. The presentations also envision new ways for utilities and consumers to work together on matters such as service connections, billing inquiries, and service restoration after an outage.

Using home energy management systems, or smart appliances that are capable of receiving communications directly, consumers can automatically control the timing and amount of their electricity consumption to manage their energy bills. With home energy management systems, they can see the cost of running equipment and how changes in electricity use impact their electricity bills and environmental footprint, and track consumption over time. Some home energy management systems will also be able to control

[5] Smart meters team with home automation networks to spare grid: Bob Gohn: http://www.digitalhomedesignline.com/howto/212200388

and integrate customer-owned resources such as photovoltaic generation or storage. Finally, these systems and smart appliances can enable automatic demand response when they are programmed to react directly to prices or other signals to reduce load provided by utilities, retailers or other service providers.

These devices support Ontario's goals for conservation and demand response. In addition, by allowing consumers to more easily respond to time-differentiated prices, home energy management systems may also help make the implementation of time-of-use pricing, including critical peak period pricing, more acceptable to consumers.

Home energy management systems also can benefit consumers in other ways. Consumers can set them to match their schedules, embody environmental or conservation values, maximize convenience and enhance security through linkages with intrusion, smoke and heat detectors and emergency notification devices. They can be linked to messaging systems whereby utilities can inform customers or individuals that they designate of impending system emergencies, planned activation of demand response programs, and restoration efforts during power outages.

Numerous companies are developing these systems using different equipment and approaches. Some systems envision direct communication of price and other signals to smart appliances while others rely on a home energy management device as a central controller. Some of the controllers are internet based and work off home computers, while others use a dedicated unit (like a multi-function remote control). All the systems embody communications that allow them to access information delivered through the smart meter or via the internet.

Taken together, technologies that exist today can create an "automatic house" that a few short years ago would have been seen as something from a futuristic movie. These systems offer consumers choice. They can actively monitor their energy use or "set it and forget it." They also offer the prospect of more efficient homes leading to significant reductions in residential energy use and peak demand.

The keys to consumers fully realizing the opportunities offered by home energy management systems are:

- universal availability of timely information on consumption and prices through a smart meter with two-way communications capability or via the internet
- prices that reflect the cost of energy at different times
- widespread availability of in-home devices that allow consumers to manage their energy use
- recognition that these devices are easier and cheaper to install as part of new construction and that increased interaction with the home building community is necessary to facilitate installation in new residences
- widespread availability of smart appliances and equipment that can be controlled directly or by home energy management systems
- education about what these devices do and how their use can benefit both consumers and the environment

The Forum identified several barriers to wide spread implementation of home energy management systems and smart appliances and equipment. As with many smart grid technologies, home energy management systems can produce benefits that are only captured in part by the consumer that invests in these systems.

These benefits include:

- lower peak demand on distribution and transmission systems
- reduced generation investment and cost from controlling peak energy use
- improved environmental performance from peak reduction and overall energy conservation

However, despite the fact that consumers may not capture the full value of the benefits that their investment creates, research presented to the Forum supports the view that consumers do consider how their actions contribute to a better environment when making energy choices.[6]

With respect to the development of home energy management systems, there is uncertainty regarding how these devices will be provided to utility consumers and under what conditions. Specifically, will these devices be provided by distribution utilities, by competitive third party suppliers, or by both? If distributors provide them, how will the costs be recovered and what conditions are necessary to avoid unfair competition? If third parties provide them, how can consumers be assured that the device they purchase can work with their meter or receive price and consumption information through some alternative means? Irrespective of who provides these systems, how can the confidentiality of consumer information continue to be protected?

The Forum believes that consumers are best served when they have the maximum opportunity to procure innovative products. In this way, consumers can decide for themselves which devices and service offerings best meet their needs. To that end, the OEB should clarify the terms and conditions under which consumers can obtain these systems from their local utilities. One potential approach is to allow distribution utilities to provide these devices as part of their conservation efforts in the same way they currently provide direct load control devices on air conditioners, water heaters and swimming pool pumps.

RECOMMENDATIONS

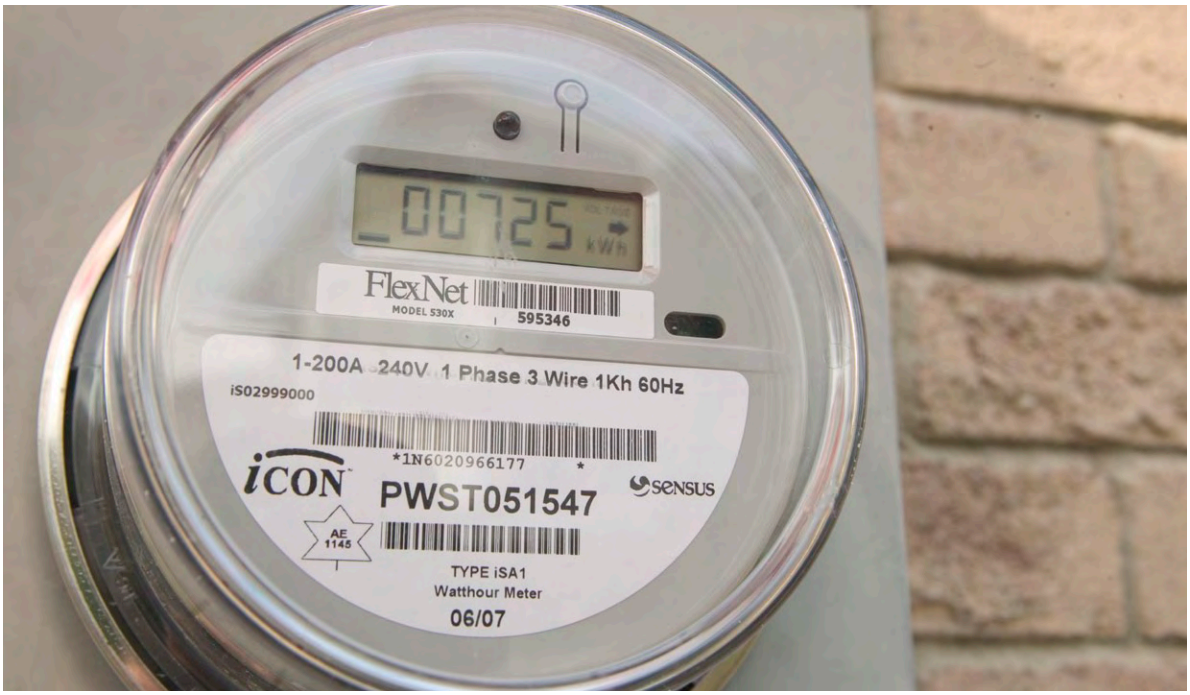
Consumer recommendations are intended to assist consumers in making informed choices on electricity consumption and enabling them to manage their consumption in response to prices or to reflect other values.

- Consumers and their designated representatives should have access to timely information on their consumption and the price they are being charged from a smart meter with two-way communication capability or via the internet. Consumers should pay prices that reflect the cost of energy at different times.
- Consumers should have the ability to obtain in-home energy management devices and services from their distribution utility, retailers or other providers of their choosing.
- The impact of home energy management systems should be tested through research and demonstration undertaken by those providing these systems. The non-proprietary results of these efforts should be widely shared.
- The Ministry of Energy and Infrastructure in consultation with distributors, retailers and other providers of in-home devices and services should develop consumer education materials designed to explain how such devices and services can help manage electricity costs, improve comfort, help the environment and promote the reliability of the electricity system.

[6] Plugging in the Consumer – Innovating Utility Business Models for the Future: Michael Valocchi, IBM Global Services: http://www.ieso.ca/imoweb/pubs/smart_grid/Plugging_in_the_Consumer-IBM.pdf

Distribution

Ontario's distribution system brings electricity to the vast majority of homes and businesses in the province. Historically, the principal job of distributors has been to deliver electricity to consumers reliably and affordably. Today, this job is rapidly expanding to include the provision of smart meters, the integration of distributed generation and assisting communities and consumers in meeting their energy needs on a sustainable basis. Distributors are being challenged to perform these new functions and continue performing existing functions, all while managing costs. Smart grid development is essential if the distribution system is to meet this challenge.



OPPORTUNITIES AND BARRIERS

Smart Meters

Ontario has made an impressive start toward empowering consumers through its decision to mandate that all utilities equip their residential and small business customers with a smart meter by 2010. By creating a potential two-way communication path between consumers and utilities, this decision provides a cornerstone for future smart grid development.

To leverage the potential of smart meters, additional steps are needed. The current approach of setting the minimum functionality of meters through regulation is cumbersome in light of the rapid evolution of smart meter technology. If this approach is retained, however, the minimum functionality should be expanded to include two-way communications, and the ability to detect outages and transmit this information back to distributors (known as "last gasp" functionality).[7] Two-way communications will allow utilities and other service providers to easily provide price information and, if critical peak pricing is implemented, to notify consumers of critical peak pricing events. "Last gasp" functionality will allow smart meters to help pinpoint outage locations and improve service restoration by ensuring that no consumers are missed because of a secondary outage condition when service is restored to an area. Utilities should continue to be able to seek cost recovery for additional functionality that benefits customers in applications before the OEB.

The consumption and price data or other signals provided through smart meters can provide important information for home energy management networks. Customers or their authorized service providers should be able to access this information from the consumer's smart meter for use by home energy management systems.

More work should be done to extend the benefits of smart meters to those customers who live in multi-unit buildings that are bulk metered. In this arrangement, building residents do not pay for their own usage directly, but instead the electricity costs for the building as a whole are paid by all occupants through rental rates or common area charges. Under current regulations, smart sub-meters may be voluntarily installed in condominiums at the discretion of the individual condominium board or the condominium developer for new buildings. Smart sub-metering activities in condominiums are overseen by the OEB, who in consultation with stakeholders, has developed a Smart Sub-Metering Code to ensure the protection of these consumers. The regulations dealing with condominium corporations are an important first step in the rollout of smart sub-meters in the multi-unit residential sector and further regulations should be considered for multi-unit rental buildings.

While smart sub-meters may not be appropriate for some multi-unit buildings because of centralized provision of heating and cooling or wiring arrangements, additional work is necessary to promote installation of smart meters whereever they can provide residents with meaningful ability to control their electricity use. Smart sub-metering will help empower Ontarians with the tools to control their energy use so that they are able to become full participants in the culture of conservation.

[7] Two way communications capability is already present in virtually all the smart meters being installed in Ontario and "last gasp" is available on some of the smart meters being installed.

Distribution Automation

The smart grid will impact virtually every aspect of the distribution system by making system conditions more visible right down to the customer level. This visibility will promote reliability, faster service restoration, enhanced maintenance practices and improved planning. When system visibility is combined with computer analytics and intelligent controls, the result will be to increasingly automate operation of the distribution system. In the future, the smart grid will enable distribution systems that can use sensors and computer analysis to predict system disturbances, take action to avoid their occurrence, and automatically reconfigure the grid to minimize the impacts of faults that do occur.[8]

Starting with the customer, smart meters will let system operators know whether a home or business is without power even if it is unoccupied. With additional sensing capability installed, smart meters could also indicate the voltage and power quality at the customer's meter. This will allow utilities to better understand conditions throughout their distribution networks. Ultimately, consumers with unique needs for power quality, such as manufacturers with sensitive electronic equipment, will be able to be served by equipment that is designed to provide the power quality that they are willing to purchase. Functionality available for smart meters can also permit automatic initiation and disconnection of service.

Moving up into the distribution system, sensors can communicate the operating state of distribution transformers and lines. This information will improve utilities' ability to operate the distribution system as it grows increasingly complex. Advanced transformer energy monitoring combined with information from smart meters at customer locations also will provide information on the loss or theft of energy throughout the system. "Flexible AC transmission systems" (FACTS), a technology that is being used more widely on the transmission system to control power flows is also being introduced for distribution lines. Fault detectors and grid automation in some circumstances will allow electrical faults to be automatically located, isolated and the grid restored without operator intervention and within minutes of the fault occurring.

At distribution substations, sensors will provide information on loading and operating conditions, station security and physical condition. Communicating this information back to the utility and applying computer analytics to it will allow distribution operators to better understand and control these components, including determining their maintenance needs and risk of failure. This information can also feed into systems that automatically control voltage and reactive power to help maintain delivery voltage and reduce line losses. In summary, this information will assist in optimizing the use of the distribution system and scheduling maintenance work.

[8] Smart Grid to Provide Capacity Relief to Distribution Utilities: Jim Blackman and M.L. Chan, Quanta Technology: http://www.ieso.ca/imoweb/pubs/smart_grid/Quanta_Technology.pdf and CURRENT Smart Grid Overview: Daniel Ripchensky, Current Group LLC: http://www.ieso.ca/imoweb/pubs/smart_grid/CURRENT_Group_Presentation.pdf



Sensing and communications equipment will be particularly helpful in managing outages and restoring power. Sensors can communicate outage information directly into a utility's Outage Management System. This system can begin automatically notifying consumers through cell phones or text messages that the utility is aware of the outage and is working on restoration. Subsequent communications can provide consumers with estimated restoration times. Linking service crews directly into the Outage Management System through mobile communications and equipping crew vehicles with Global Positioning System (GPS) capability and access to the utility's Geographic Information System will allow crews to better understand the nature of outages, see the equipment involved, and go directly to the outage location.

An issue for distributors implementing smart grid technologies is the need to collect, cull, manage, store, retrieve and integrate the large amount of data that smart devices will produce. The presentations highlighted the challenge inherent in managing this vast amount of data securely and efficiently and turning it into actionable information. There is a risk of collecting data "for data's sake" and by so doing overwhelming the ability of people and processes to use the data collected effectively.

Data produced will need to be accessible to and usable by a variety of distribution utility computer systems including those that control the system, map and locate system equipment, manage outages, handle meter data and billing, and maintain customer information. Enterprise integration, which allows these systems to access the data they need from a common source, using a common format and integrating them through a common service architecture, will be necessary for distributors to achieve the full functionality of a smart grid.[9]

The challenge of moving to a smart gird is significant from both a technological and human resources perspective. Many of the technologies that will be used to collect, manage and analyze smart grid information are currently being developed. As with all "leading edge" technologies, there is a substantial risk of false starts and dead ends, and a virtual certainty that integration with existing technologies and systems will prove to be more difficult than advertised. From a human resource perspective, learning to understand and

[9] Implementing the Smart Grid: Enterprise Information Integration: Ali Ipakchi, Pages 4-6: http://www.gridwiseac.org/pdfs/forum_papers/121_122_paper_final.pdf

use the full capabilities of smart grid technologies will require a substantial training effort and opportunities to practice using the new tools in a simulated environment. Current business processes will also need to be modified in light of the new information available and the capabilities of smart grid technologies.

In addition to impacting operations, the smart grid will also enable much more detailed planning as utilities gain more precise information on the loading of their equipment down to the individual customer level. By deploying sensors on feeders, lines and substations, utilities will be able to more accurately determine the need for additional infrastructure and to better analyze which capital additions will provide the greatest system benefit.[10] Better analysis of the timing and configuration of needed capital additions will promote efficient capital spending.

As discussed below in the Distributed Resources section, a smart grid is essential if the province is to maximize the generation, storage and demand response resources connected to distribution lines. The distribution grid was originally developed to deliver power to consumers. The sensing and communications that the smart grid will bring are necessary, but not sufficient, to meet the distribution system's expanded role of incorporating substantial amounts of generation safely and efficiently.

Micro-Grids

A micro-grid is an integrated energy solution that serves a group of consumers, such as a neighbourhood or a town, or a single large consumer, such as a university. Micro-grids use a variety of energy, communications and computer technologies to allow the consumers served by them to meet all, or a large portion, of their total energy needs (electric and thermal) with devices that form part of the micro-grid. While a micro grid can be designed to allow those it serves to achieve energy self-sufficiency, it is generally not independent of the larger electricity system.[11] Instead, it buys and sells electricity from the grid to take advantage of price differentials and when necessary to address surpluses or deficits in micro-grid production. For participants, micro-grids can deliver local control of energy production, more efficient use of combined heat and power, greater reliability and improved power quality, and the ability to better tailor their energy supply to their energy needs and environmental values.

Substantial technical, legal, regulatory and institutional issues arise in developing and operating micro-grids, particularly those created by a third party aggregating multiple consumers currently served by an existing distributor. In this context, interconnection of micro-grids to the existing distribution system will raise technical issues related to worker and public safety, equipment protection, and impacts on service to other consumers.

Legal and regulatory questions involve the status of the micro-grid operator as a regulated distributor, the ability of the micro-grid to use existing distribution facilities and at what cost, the ability to construct new distribution facilities that duplicate existing ones, and the nature of an existing distributor's continuing responsibility to serve consumers on the micro-grid. Even if the micro-grid were to be created and operated by the incumbent utility, issues would arise with respect to allocation and recovery of costs associated with the micro-grid's development, operation and maintenance. To the extent that a micro-grid served a single large customer rather than multiple consumers, these issues are likely to be less complex.

[10] Smart Grid to Provide Capacity Relief to Distribution Utilities: Jim Blackman and M.L. Chan, Quanta Technology: http://www.ieso.ca/imoweb/pubs/smart_grid/Quanta_Technology.pdf

[11] Micro-grids can also be developed in remote areas where connection to the larger grid is uneconomic. Introduction to Distributed Generation: European Commission: http://ec.europa.eu/research/energy/nn/nn_rt/nn_rt_dg/article_1158_en.htm

RECOMMENDATIONS

Distribution recommendations are intended to encourage actions in the distribution sector that will accelerate development of a smart grid.

Smart Meters

- Utilities should continue to propose smart meter functionality consistent with the best interests of their customers and apply for OEB approval to recover the costs of this functionality in rates.
- If smart meter minimum functionality continues to be prescribed by regulation, then the minimum should be revised to include two-way communications and "last gasp" capability.
- The Ministry of Energy and Infrastructure should undertake further consultation with the goal of ensuring that smart meters or smart sub-meters are installed in all multi-unit residential buildings where it makes sense to do so.

Distribution Automation

- Utilities should develop their proposed smart grid investments as part of their capital plans.
- Utilities that wish to investigate and test smart grid technologies on their systems should be encouraged to propose demonstration projects that will assist them in testing the performance of available smart grid technologies and quantifying their costs and benefits. The non-proprietary results of these projects should be made widely available.

Micro-Grids

- The Ministry of Energy and Infrastructure in consultation with industry and consumers should undertake research to detail and clarify the technical, legal, regulatory and institutional issues associated with micro-grids to better assess their future applicability in Ontario.

Distributed Energy Resources

Distributed energy resources are generation, storage and demand response connected to the distribution system. These resources may be located at customer premises or a dedicated site. Distributed energy resources offer many potential advantages to the electricity system. They are small scale, can be located close to load, and many use renewable technologies. They can be used by distributors to support grid operations and can be considered as a resource in integrated distribution grid planning. They can also support transmission operations and planning. The challenge lies in using these resources effectively and in connecting them to a distribution grid that historically has been designed and operated to deliver electricity to consumers.[12]



OPPORTUNITIES AND BARRIERS

Distributed Generation

Distributed generation is small scale generation that feeds into the distribution grid. Much of this generation uses renewable technologies, which are a cornerstone of Ontario's future energy supply. Through the work of the OPA, Ontario has been very successful in contracting for renewable generation. The OPA estimates that there are almost 5,000 megawatts (MW) of renewable distributed generation projects that either have a Renewable Energy Standard Offer Program (RESOP) contract or are in the connection process.[13]

[12] For information on work underway in Canada: http://canmetenergy.nrcan.gc.ca/eng/renewables/integration_der.html

[13] Distributed Energy: Paul Shervill and Kevin Devitt, Ontario Power Authority: http://www.ieso.ca/imoweb/pubs/smart_grid/OPA-Distributed_Generation.pdf

Most of these projects are seeking to connect to the distribution system in rural areas served by Hydro One. The electricity being injected into the distribution system by distributed generation may impact on upstream transmission reliability, the operation and maintenance of distribution equipment, and the quality and availability of service to consumers served by that equipment. Because distributors currently have little ability to monitor the output of distributed generators and no means of controlling this production, they must find ways to ensure that the presence of generation does not endanger worker or public safety, interfere with the operation of protective equipment or impair service to consumers. Currently these solutions can significantly increase the cost of connecting renewable generation, making some smaller projects uneconomic. Smart grid technology can help address the technical issues by allowing distribution lines to accommodate more generation without compromising service to consumers on those lines, overall grid reliability (including upstream impacts on the transmission system) and safety.[14]

Distributors are investigating cost-effective technical solutions that will increase the amount of distributed generation that they can safely connect to distribution lines. Some of these solutions will involve increased monitoring of generation and equipment condition, and may involve the ability to control the output of certain generators on occasion to ensure that overall, the maximum amount of generation can be connected. Others will use innovative new approaches to meet utility safety requirements, avoid islanding and maintain voltage and frequency. These technical issues are not insoluble, but further research is necessary to develop and test cost-effective solutions.

As more distributed generation comes on-line, the need to control its output will grow. Controlling this output will require clear rules concerning the responsibilities of the generator, the authority of the controller, the purposes for which control can be exercised, and any compensation provisions.

The current connection process can adversely impact the installation of distributed generation by allowing developers to retain priority in the connection queue without demonstrating continued progress toward completing their projects or the project's continued viability. As a result, in many parts of Ontario, projects that are sized at, or just below the 10 MW RESOP cut-off have occupied all the available connection capacity at distribution substations simply by applying for Connection Impact Assessments and paying the fee, typically $5,000. The OEB, OPA and Hydro One are currently investigating approaches to address the economic and regulatory issues associated with connecting the existing list of proposed distributed generation projects by considering ways to develop a mechanism to link continued maintenance of queue priority to obtaining a contract and meeting contract milestones.

Connection limits have had the effect of holding up some projects that are ready to proceed, particularly very small farm biogas projects (less than 500 kilowatts (kW)). Under current rules, connection priority is established based on the impact assessment application and there is little requirement to actually move the project forward to completion in advance of the three-year in-service window for RESOP. The OEB has issued draft rules generally allowing for the connection of very small generation projects outside the connection queue.[15]

[14] DG Integration Key to Smart Grid: Ravi Seethapathy, Hydro One: http://www.ieso.ca/imoweb/pubs/smart_grid/HydroOne-DG.pdf

[15] Notice of Proposed Revised Amendments to the Distribution System Code: Ontario Energy Board: http://www.oeb.gov.on.ca/OEB/_Documents/EB-2008-0102/Notice_ProposedRevisedAmendments_DSC_20081209.pdf

Storage

Electricity storage offers a number of potential benefits to the electricity system. For variable renewable generation (wind and solar) and at times of surplus baseload generation (from nuclear and hydroelectric generation), storage can be used to capture energy that would otherwise go unused and make it available to meet peak demand. Storage can also be used to firm up the capacity of intermittent generation so that a greater percentage of this capacity can be counted toward meeting peak load for planning purposes. Finally, storage can be used to moderate price differentials by storing off-peak energy and providing it on-peak.



Source: Planetary Engineering Group Earth

Beyond providing peak period energy, storage can provide ancillary services such as load following, area regulation and black start capability, and may also be used for grid stabilization and grid operations support. On the distribution system, storage can be used to defer investment in substations by shaving peak load and can also be used to improve local area reliability. The Forum was shown how American Electric Power (AEP) is using storage for these purposes and how, by configuring storage equipment in transportable units, AEP can reuse this equipment at different locations as local needs change. Storage sited at customer facilities can be used for load shifting and backup power.

Several technologies have the potential to provide storage including: conventional lead acid batteries, advanced batteries (e.g. sodium/sulphur, zinc/bromide and metal/air), flow batteries, flywheels, pumped generation storage (PGS), compressed air storage and superconducting magnetic energy storage (SMES). These technologies all have advantages and limitations. Some technologies, such as PGS and, to a large extent, compressed air, depend on the availability of sites with particular geological characteristics.[16]

[16] Discussion Paper 4: Supply Resources (IPSP Application, Exhibit C, Tab 8, Schedule 1, pages 93-100), OPA: http://www.powerauthority.on.ca/Storage/50/4552_C-8-1.pdf

Storage is subject to the same issue of diffuse benefits that impacts many other smart grid technologies. While storage can offer demonstrable benefits in terms of both the electricity system and the environment, it is difficult for a single entity to capture all of the electric system benefits, and the environmental benefits may not be monetized. As a result, storage typically has been confined to niche applications and sites with very favourable characteristics.

Regulatory uncertainty is an impediment to the implementation of storage. While a storage facility is never a net generator of electricity, it does discharge electricity when being drawn down. At the same time it can also function like a capacitor bank or a back-up power supply. These multiple functions create uncertainty as to the categorization of storage under the OEB Act and, consequently, uncertainty about how it can be deployed and by whom. For example, can a distributor install a storage device where it is a cost-effective means of providing voltage support or deferring a substation upgrade by helping to reduce peak load?

The lack of differentiation between peak and off-peak in the pricing offered to intermittent renewable generators undercuts the value to those generators of incorporating storage into their projects to increase on-peak availability. Similarly, because the cost of addressing the variable nature of wind and solar is currently borne by the electricity system as whole, there is little, if any, incentive for developers of these projects to consider storage.

Demand Response

Demand Response (DR) is a change in consumption in reaction to prices or other signals. DR can provide significant benefits to the electricity system by avoiding the need for additional facilities to meet extreme peak demand that occurs a few hours each year, reducing the use of expensive peak generation and making better use of variable generation sources when they are available. With the growing penetration of variable resources, DR can increase the systems' ability to use load to address supply variations. DR can be achieved through behavioural changes, changes in processes or equipment, the use of customer-owned generation or through direct control of appliances and equipment.



The OPA offers several DR programs for large commercial and industrial consumers and has entered into a DR contracts that pay for demand reductions against a baseline.[17] Many distribution utilities offer residential/small business direct load control programs under contract with the OPA that reduce demand by controlling the consumption of devices such as central air conditioners, electric water heaters and swimming pool pumps during peak periods in exchange for a one-time payment to participants.

While the reasons that individuals and companies participate in DR are varied and complex, the fundamental intent of DR is simple, reduce the cost of producing and delivering electricity by making consumption more responsive to production cost. To the extent that this cost is visible to consumers through prices, DR will be facilitated. DR will also be facilitated as smaller volume consumers come to understand the difference between peak and off-peak consumption and prices through education about smart meters and time-of-use rates.

RECOMMENDATIONS

The Distributed Energy Resources recommendations are intended to further Ontario's ability to incorporate renewable generation, expand opportunities for consumers to produce their own power, and increase the use of storage and demand response.

Distributed Generation

- Distributors should be required to offer to connect renewable generation just as they are currently required to offer to connect consumers.
- Distributors and the OPA should develop and propose mechanisms whereby dispatchable renewable generation projects and storage can be operated to maximize the total amount of generation that can connect to the distribution system.
- In order to plan and operate the grid reliably and efficiently, distributors, transmitters, the OEB, OPA and the IESO should work together to:
  - develop requirements for and propose sufficient monitoring of distribution connected generation, energy storage, and responsive load;
  - determine the authority necessary to direct the operation of these facilities, the conditions under which their operation could be directed and any compensation that would be provided to the facility;
  - propose contractual and pricing arrangements with distribution connected generation, energy storage, and responsive load that support efficient grid operations and are consistent with the operation of the wholesale electricity market;
  - coordinate the development and implementation of grid control and information systems to facilitate the actions listed above.
- The OEB, the OPA, Hydro One and all other affected distributors should continue working together to unblock the distribution connection queue and assure that projects can retain their queue positions only if they demonstrate progress toward completion in a timely manner against established milestones.

[17] Demand Response Programs, OPA: http://www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=147

Storage

- To encourage the cost-effective use of storage, the OPA should investigate structuring payments to variable generators that reflect the value of production in different time periods.
- Through legislation, regulation, or other appropriate means, the Ministry of Energy and Infrastructure should clarify that distributors are permitted to own, provide and operate storage devices where such devices can promote the cost-effective provision of distribution services.
- Distributors should develop storage demonstration projects aimed at gaining a better understanding of how various storage technologies can be used and the technical and institutional barriers associated with these technologies. The non-proprietary results of these projects should be made widely available.

Demand Response

- Distributors should continue to develop innovative demand response programs that will facilitate the cost-effective provision of distribution service or the deferral of distribution system investment.
- The OPA, distributors and aggregators should strive to expand the range of demand response products available to maximize opportunities for all customer types to participate in demand response.

Transmission

INTRODUCTION

Ontario's transmission lines are the highways of the province's electricity system, designed to efficiently move large volumes of electricity from generators to load. Ontario's transmission system directly serves large generation facilities, large electricity consumers and the distribution system. Historically, Ontario's transmission system was primarily constructed to link remote generators to the load centres within the province in a cost effective manner. To achieve this goal, Ontario was at the forefront of developing technological solutions that maximized the ability to move electricity over distances efficiently and while maintaining system stability. The result is that today, Ontario's transmission grid is relatively sophisticated in its provision of reliable and affordable service to its customers.

Like all other parts of the electricity system, however, the transmission grid is facing the need for refurbishment and reinvestment. This renewal will involve the increased incorporation of smart grid technologies as old equipment is replaced. In addition, the transmission system must continue to evolve in response to changes in Ontario's resource mix including the development of renewable resources, integration of storage technologies, increased reliance on demand response, the refurbishment of existing and the development of new nuclear generators and the shutdown of coal-fired generation. To meet these challenges, the transmission system must become even more sophisticated, reliable, efficient and flexible through the implementation of additional smart grid technology.



OPPORTUNITIES AND BARRIERS

Historically, the transmission system and the connections to it have been much more visible to grid operators than the distribution system. The length of transmission lines, their relatively small number compared to the number of distribution lines, and the large volumes of energy that they transfer have justified investment in communications, control, sensing and imaging equipment that historically has been uneconomic for distribution. With the development of new technologies and the emergence of new challenges, however, the transmission system has both the ability and the need to become even more technologically advanced.

Technologies such as phasor measurement units and advanced phasor visualization and decision support tools will allow for greater visibility over a wider area than is currently possible.[18] Beyond visibility, however, the focus of smart grid investment will be on technologies that allow for more efficient use and greater control of the transmission system. These investments will enable the transmission system to accommodate increasing amounts of generation from more numerous and less predictable sources that are widely dispersed throughout the province.

Technology will also facilitate increased coordination between transmission and distribution operations. This coordination will be enabled by the implementation of the smart grid within the distribution sector and necessitated by the changing role of the distribution system and Ontario's evolving generation mix. Increasingly, distribution will be feeding energy into the transmission grid, not just withdrawing energy from it. Greater ability to monitor the operation of generation connected to the distribution system and enhanced control of how electricity flows over the transmission system will permit both transmission and distribution grid assets to be used more efficiently. Appendix B illustrates the major information flows necessary for coordination among transmission, distribution and other elements of the electricity system.

The large amounts of wind and solar generation being developed and connected to the transmission system require increased flexibility to enable rapid response to the changes in the availability of these variable resources. Beyond addressing the variability of currently planned resources, the need for flexibility will only increase because the grid must be able to accept new types of generation and storage technologies, each with its own operating characteristics, as they are developed. The electricity market must evolve along with the grid to ensure that developing resources are enabled.

Addressing transmission congestion is another important function of smart grid technology. The more congestion can be reduced, the greater the province's ability to move generation to load. Increased implementation and use of large scale demand response, storage and technologies such as FACTS will allow operators to make more intensive use of the transmission grid. More aggressive fault management, isolation and restoration will also be possible, thereby reducing the number of transmission system disturbances that impact service to consumers and the availability of generation.

Monitoring technology will increase the visibility of conditions on interconnected systems beyond Ontario. This will enhance security and reliability by giving Ontario operators more advance notice of problems developing elsewhere and more tools to prevent these problems from impacting Ontario. Greater ability to control the transmission grid and software developments that improve market integration between jurisdictions will improve the efficiency of trade with Ontario's neighbours. This will allow the province to take greater advantage of regional diversity in generation and load.

[18] Context and Candidate Outcomes to Shape North American Electric System Transformation: Carl Imhoff, Pacific Northwest National Laboratory: http://www.ieso.ca/imoweb/pubs/smart_grid/PNWL-Carl_Imhoff.pdf

RECOMMENDATIONS

The Transmission recommendations are intended to improve coordination and monitoring of the electricity system and market integration.

- Using established forums, the IESO, Hydro One and other transmitters should work with interconnected systems to investigate using smart grid technology to provide additional wide area monitoring of the grid.
- The IESO should continue exploring ways in which the market can evolve to take advantage of benefits enabled by the smart grid.
- The IESO should explore using additional smart grid technology to improve market integration and performance with neighbouring markets.

Communications

INTRODUCTION

Communications technology is at the core of the smart grid. Communication brings the data generated by meters, sensors, voltage controllers, mobile work units and a host of other devices on the grid to the computer systems and other equipment necessary to turn this data into actionable information. To serve the emerging needs of the smart grid, communication must be pervasive, rapid, robust even in emergency conditions, scalable (but with high initial capacity), and most of all, secure. To be effective, communications must be governed by clear standards and support the interoperability of the many devices that will connect to the smart grid.



OPPORTUNITIES AND BARRIERS

Ontario consists of a large and geographically diverse area. No single communication technology will meet the needs of the smart grid throughout the province. Instead, individual utilities will select the communications choices that are appropriate in light of available options, geography, customer mix, equipment being served, load and generation. These choices will rely on a variety of technologies including cellular spectrum, fibre optics, power line carrier (including broadband over power line), microwave, radio (licensed and unlicensed), WiMax, WiFi and others. These technologies may be utility-owned and operated, or provided under contract with a communications company. Irrespective of the technology chosen or the provider, certain characteristics are required for the smart grid to succeed.

Grid communications must be highly reliable because they carry critical data necessary for operations, billing and the safe and efficient restoration of service during outages. Getting the electricity system back into service as quickly as possible provides essential support to the work of police, fire and ambulance services in responding to natural disasters and other crises. Moving to a smart grid will only increase the importance of reliable communications because it will increase the amount of operational data that is being communicated and the reliance on that data in managing the grid. Using multiple communication paths and backup power supplies are two ways of addressing the need for reliable communications.

As part of their deployment of smart meters, utilities are installing various two-way communication systems throughout the province. Unlike mobile devices such as cell phones, which can tolerate "dead zones" as they move between towers, stationary devices such as smart meters require a communication system that reaches every customer.

Even with the requirement to communicate with all consumers, however the communication systems that the utilities are developing for smart meters will not be adequate to support full smart grid development. The communications needs associated with the collection of meter data are different from those of grid operations. Additional bandwidth and redundant service will be needed for grid operations because of the quantity of operational data, the speed required to use it and its criticality. The latter factor will become particularly important over time as the smart grid advances from monitoring the state of grid equipment to automatically controlling and restoring the grid with limited human intervention. Thus there is not a single smart grid communications solution. Instead, a variety of communications technologies are required to perform different functions and support various aspects of the smart grid.

A number of utilities across Canada are working with Industry Canada to achieve a dedicated spectrum for electric utility communications. As a result of these efforts, Industry Canada has proposed making a 30 megahertz (MHz) sub-band at 1800–1830 MHz available for the management and operation of the electricity system.[19] This proposal, when finally approved, will allow electric utilities and their service providers access to this communications spectrum to help communicate throughout their service territories, which will facilitate the development of a smart grid. This development will be particularly important in those rural and remote areas where telecommunications options are limited. A final decision by Industry Canada to dedicate this spectrum for electric utility use will place Canada in the forefront of countries seeking to create the pervasive and affordable telecommunications options necessary for smart grid development.

The developing nature of smart grid technology has three significant implications for communications. First, smart grid communications development must match smart grid development. While the initial communications deployment can be configured and sized to accommodate the first generation of smart grid equipment, such as smart meters; ultimately the communications infrastructure must be capable of servicing the full range of smart grid equipment installed. Given the uncertain pace at which smart grid technologies will be implemented, communications system should be scalable to allow for the addition of new devices as they are developed. Communications systems also will need to be in place for the anticipated service lives of smart grid equipment, which can range from years to decades.

Second, smart grid communications must be developed based on open standards so that the widest possible range of devices can be employed and the development of new devices and entry by new vendors is encouraged. The communications protocols, the methods of addressing various devices and techniques for organizing the data produced by these devices all must be standardized. To the extent that utilities have already implemented proprietary technologies in their smart meter deployments, additional bandwidth and addressing techniques may be necessary to enable translation between proprietary and open communications standards.

[19] Connectivity: the Key to the Smart Network: Richard Bertolo and Leonard Gross, Hydro One: http://www.ieso.ca/imoweb/pubs/smart_grid/HydroOne-Connectivity.pdf

Third, communications must be designed with interoperability as a requirement.[20] While standards allow many different devices to interact over a given communications technology, interoperability allows a variety of technologies to work together. That is, the devices can exchange actionable information and then use that information to perform the functions for which they are designed. This characteristic is essential given the many different types of equipment that make up the smart grid. It also supports the ability to contract with different vendors for different types of equipment and recognizes the likelihood that the many different companies that collectively own and operate the electricity grid will select different technologies and providers that will all need to work together.

Cyber Security

Moving to a smart grid poses opportunities and risks with respect to cyber security.[21] The opportunities arise because the sensors, communications and computer analytics that comprise the smart grid will allow a much more sophisticated view and analysis of system operations. The risks, which are always more prominent in any security discussion, arise because smart grid development will entail placing millions of devices on poles, lines and the sides of houses throughout the province, all of which can communicate back into utility computer systems.

The installation of smart meters has already created millions of potential access points in Ontario. Smart grid deployment will involve additional potential access points through monitors and sensors that connect into core utility operating systems. The multiplicity of physically unsecured entry points by itself creates a substantial security risk. The need to deploy devices in unsecured locations places the smart grid in stark contrast to a typical computer network where limiting physical access to network devices is an important element in enhancing cyber security.

Additional risks occur because of the need to make some devices accessible to third parties. For example, non-utility generators may need to access sensors that provide line data to automate their disconnection and reconnection. Third parties also may access meter data in conjunction with home energy management systems.

Recognizing that it will not be possible to secure every potential access point, utilities and equipment vendors must develop and deploy security measures that make their systems resistant to penetration, able to detect intrusions, and capable of isolating specific areas to limit the damage that an intruder can accomplish. Hardening communications and computer systems against cyber intrusions will add cost, but must be done to assure the security of critical utility infrastructure.

[20] The U.S. Department of Energy has formed the GridWise® Architecture Council "to promote and enable interoperability among the many entities that interact with the nation's electric power system." The U.S. 2007 Energy Independence and Energy Security Act (EISA) required the National Institute of Standards and Technology (NIST) to coordinate the development of a framework to advance interoperability in the smart grid. For information on interoperability see, http://www.gridwiseac.org/about/mission.aspx and http://www.nist.gov/smartgrid/

[21] Cyber Security and the Smart Grid: Doug Westlund and Peter Vickery, N-Dimension Solutions Inc.: http://www.ieso.ca/imoweb/pubs/smart_grid/N-Dimension.pdf

RECOMMENDATIONS

These recommendations are intended to ensure that utilities plan for and develop the standards, security and communications infrastructure necessary for the realization of a smart grid.

- The OEB should require distributors, transmitters and the IESO to address the communications needed to accomplish the full range of their intended smart grid activities into their capital investment plans. This should include as appropriate for each entity:
  - Immediate communications needs associated with smart meters;
  - Longer-term communication needs associated with other smart grid applications;
  - Efforts to make communications scalable so that they can accommodate additional smart grid functionality as it develops;
  - The need for cyber security and defence in depth;
  - Reliance on open standards and interoperability principles to maximize future technology options.
- To ensure the widest range of technological choices, entities investing in Ontario's electricity system and those developing home energy management systems should continue to work with standards organizations, such as IEC, IEEE, Zigbee and Home Plug, to develop and promote open communications standards.

Electric Vehicles

INTRODUCTION

Electric vehicles hold tremendous promise for Ontario. They can help clean up our air, reduce our dependence on petroleum and create new green jobs for the province. Building on its established automotive base and its commitment to a greener future, Ontario has an opportunity to become a leader in the development and deployment of electric vehicles. The smart grid is necessary to facilitate the large scale adoption of electric vehicles by enabling them to be charged in ways that are convenient and reduce the potential for adverse impacts on electricity infrastructure and customer service. The smart grid may also allow the energy stored in batteries to become a source of energy to help meet peak demand.



OPPORTUNITIES AND BARRIERS

Several different models of vehicles and different vehicle charging arrangements are currently being developed. Production vehicles that are available commercially today are generally partially driven by electricity and partially by fuel (HEVs – hybrid electric vehicles), and rely on refuelling at the pump and an onboard motor to generate electricity. HEVs provide a driving range like that of a conventional fuel-burning vehicle. Some hybrids currently permit plug-in charging (PHEVs) and more are on the way.

Electric vehicles (EVs) are also being developed that will be fuelled solely by the electricity stored in their batteries. EVs need a method of recharging when their batteries are depleted. Historically EVs have been suitable only for niche applications because of their limited performance and range due to battery size and weight limitations. The EVs currently being developed are expected to have greater range, longer-live batteries and performance similar to current vehicles.

Several approaches are being investigated for recharging EVs. One approach proposes dedicated charging stations in drivers' homes, parking lots and retail locations to charge batteries when they are parked and battery exchange stations that will allow depleted batteries to be replaced quickly with fully charged ones for longer trips. This model relies on a dedicated mobile communications and billing system to recover charging costs. Another approach envisions plug-in charging at home, at work or in parking lots. Consumers would either be charged a fee to plug-in away from home or sensors would be used to link each vehicle to its home electricity account for billing.

Research is also underway on the use of electric vehicle batteries as a source of widely dispersed storage. Vehicle batteries can potentially provide the types of benefits described above with respect to storage, but the mobile nature of vehicles and the expectation that their owners will want their batteries fully charged and available for use, provide additional challenges to using these batteries as storage. Intelligent grid technologies will be key in addressing these challenges.

As is readily apparent, widespread EV adoption will require the electricity system to develop innovative and cost-effective ways to provide consumers with the electricity they demand for charging. With different vehicle types and charging techniques come different battery sizes and charging durations, which in turn will produce different electrical loads.[22] Impacts from vehicle charging will start at the point of connection. Prior to charging vehicles at home or work, the adequacy of a building's wiring to provide safe charging may need to be addressed depending on characteristics the charging devices. Chargers currently being investigated by the Electric Power Research Institute (EPRI) have associated peak loads of between 1.5 kW and 7 kW with charging durations of between three and eight hours.[23] With significant penetration of electric vehicles, loads at the upper end of this range can have the potential to significantly impact building wiring in some instances. This could occur, for example, in suburban office parks where a high percentage of employees commute by car.

At the distribution level, the adequacy of existing local infrastructure to support a high penetration of electric vehicles is currently being reviewed in a joint study by EPRI and a number of North American utilities. This study is evaluating impacts on transformers, lines and substation equipment. Again, depending on the degree of electric vehicle penetration, innovative charging methods, such as staged charging through the use of smart grid technologies, may be needed to accommodate significant penetration of electric vehicles without adversely impacting local distribution equipment and, as a result, service to customers.

At the transmission level, both the impacts on regional transmission infrastructure from the concentrated penetration of electric vehicles in specific geographic areas and the overall impact of a different provincial load shape due to vehicle charging will need to be assessed.

In terms of energy supply, widespread adoption of electric vehicles represents a potentially significant new load. Methods must be developed so that charging is accomplished in ways that maximize the use of available generation resources and minimize peak demand increases which, were they to occur, would require development of additional peaking generation resources. The extent to which charging can be managed solely through prices or if other controls will be needed remains an open question.

[22] Electric Vehicles and the Grid: Arindam Maitra, Electric Power Research Institute: http://www.ieso.ca/imoweb/pubs/smart_grid/ArindamMaitre-EPRI.pdf

[23] Ibid

The connection between electric vehicles and a smart grid is fundamental. With smart technology, the grid can be an enabler of electric vehicles by maximizing charging flexibility; without it, the grid may be a barrier to the widespread adoption of electric vehicles. The sensing, communications and computer analytics that constitute smart grid technology will be required to ensure that electric vehicle charging is accomplished efficiently and that any impacts on the electricity system are addressed. This same sensing technology can potentially be applied to recover the cost of charging a vehicle away from its home base and include that cost on a customer's utility bill. Finally, a smart grid also is necessary to enable the large-scale use of electricity stored in vehicle batteries as a resource to meet peak demand.

RECOMMENDATIONS

The Electric Vehicle recommendations are intended to facilitate the widespread deployment of plug-in electric vehicles and the development of an electric car industry in Ontario.

- A Task Force led by the Ministry of Economic Development and involving other relevant Ministries should be created consisting of representatives from the auto sector (vehicle manufacturers and suppliers) electricity sector (OEB, IESO, OPA, distributors and generators) and universities to develop a comprehensive plan for enabling plug-in electric vehicles in Ontario. The plan would address policy, financial, and electricity system impacts of substantial electric vehicle penetration and identify what is required to ensure that vehicles can be charged as they develop. The Task Force should link to the ongoing collaborative work by the EPRI, the Society of Automotive Engineers (SAE) and standards development organizations to develop electric vehicles standards.
- The OCE working together with the automotive and electricity sectors and Ontario's universities should continue to undertake projects aimed at developing electric vehicles and the products and infrastructure necessary to support them in Ontario.

Innovation and the Economy

INTRODUCTION

The Forum heard from speakers describing the European Union's smart grid efforts and those of the United States. Through research, the Forum received additional documentation of these smart grid efforts. The smart grid is already worldwide phenomenon and will only grow as it moves from planning and demonstration projects to full implementation. Hearing these presentations and examining the research led the Forum to ask "How can Ontario enhance its position as a leader in the development and production of smart grid technologies?"



Ontario is currently home to a strong base of innovative companies that are offering products and services that help further the Provincial policy of creating a culture of conservation. For example, to support Ontario's smart meter initiative, smart meter suppliers have established a presence in the province. The smart meter initiative has also created jobs for the installation of smart meters in Ontario as well as drawing on Ontario's skilled labour force for the computer work necessary to store, validate smart meter data and integrate it into utility computer systems and the provincial data repository.

Ontario companies are also at the forefront of the emerging market for home energy management systems that consumers can use to control their electricity use and automate various functions in their homes. A recent showcase hosted by the Ministry of Energy and Infrastructure highlighted a number of these home energy management systems, some of which are currently being developed in Ontario. These devices are an important complement to Ontario's smart meter program. In addition to in-home device vendors, Ontario is also home to several energy management companies who are involved in smart grid pilots currently being undertaken by U.S. utilities.

OPPORTUNITIES AND BARRIERS

To realize the smart grid vision, new technology will need to be developed, designed and built. Where it occurs, research and development, and ultimately manufacturing, will spur innovation, economic development and job creation. The Forum believes that Ontario is well positioned to be a leader in smart grid technology because of its universities and other academic institutions, progressive companies and entities like the OCE and the OPA's Technology Development Fund.

Established by the Ontario government in 1987, the OCE drives the commercialization of cutting-edge research across key market sectors to build Ontario's economy and secure its global competitiveness. OCE's Centre of Excellence for Energy (OCEE) was established in January 2005.[24] It currently has eight projects underway or in the pipeline that relate to smart grid. All are collaboratively supported by industrial partners, academic institutions and OCE. The total investment of these projects is currently almost $12 million with about half this amount coming from OCE.

The OCE currently funds a number of projects in areas related to the smart grid. These areas include: small scale solar photovoltaic plant impacts on the distribution system and integrating large-scale photovoltaic plants into the grid; developing tools for the competitive provision of reactive power in electricity markets; working to establish a communications protocol for home energy management systems; developing a web-based tool to control energy use; and technology to improve the detection and isolation of system faults. The OCEE also has begun a process to search for new smart grid projects involving large capacity energy storage, large scale penetration of PHEVs, consumer information and methods of increasing grid capacity.

The OPA's Technology Development Fund was established in 2006 to fund projects that promote the development and commercialization of technologies or applications that have the potential to improve electricity supply, conservation or demand management.[25] The projects funded are technologies or applications that are pre-commercial or are facing barriers to commercialization. Funding is provided for further study, development, demonstration, or performance verification. OPA typically partners with the OCEE, academic institutions and research organizations.

Apart from its participation in projects with the OCEE, the OPA has helped to fund projects with the Centre for Energy Advancement through Technological Innovation (CEATI).[26] These projects involve: battery storage demonstration in a rural distribution system; developing an assessment methodology for the impact of a large deployment of PHEVs; and research on utility load control devices.

RECOMMENDATION

The Innovation recommendation is intended to advance Ontario as a leader in the development, implementation and production of smart grid technologies.

- Utilities, the IESO, the OPA, universities and OCE should conduct research and development related to smart grids to advance Ontario's leadership position in this area, promote innovation and develop green jobs in the province. The OCE should facilitate the development of a task force to produce a framework for smart grid research in Ontario that would include targeted amounts of funding and proposed funding mechanisms.

[24] Ontario Centres of Excellence: http://www.oce-ontario.org/Pages/COEEnergy.aspx?COE=EN

[25] OPA Technology Development Fund: http://www.powerauthority.on.ca/tdfund/

[26] CEATI is a global research organization aimed at developing and providing technology solutions for utilities: http://www.ceati.com/about.php

Conclusions and Next Steps

CONCLUSIONS

The diverse body of materials reviewed by the Forum highlighted a few common themes. There is tremendous excitement about the potential of the smart grid. Balancing this excitement is a recognition that not all smart grid technologies will deliver as promised. Inevitably, there will be false starts and dead ends. Open standards and integrated approaches are the keys to minimizing the risk of stranded technologies. Demonstrations and pilots are appropriate tools to test technologies to see how they perform under real world conditions.

Coordination on several different levels will be a key success factor in developing a smart grid. On the technological level, there is the need for standards and interoperatibility to allow devices to be developed by multiple suppliers. Integrating the development of workforce training and appropriate processes with the deployment of technology is also necessary. Coordinated development across the divisions of the electricity system (i.e. customers, distribution, retail service providers, transmission and generation) also will be essential for the smart grid to function as an integrated whole. To deliver on its promise, the smart grid must enable the transparent exchange of operating and price information to efficiently link customer choices with the dispatch of resources and the operation of the grid.

Better coordination will also be required between the electricity industry and other industries. Electric vehicles are a particularly good example of this type of linkage. Vehicle manufactures and the electricity industry must work together to ensure that electric cars can be charged conveniently in multiple locations and that vehicle charging can be accommodated without adversely impacting electric service.

The Forum's review of activities in Europe and the United States showed that both these jurisdictions are aggressively pursuing smart grid development. The drivers for grid modernization are somewhat different in each area depending on their existing resource base and the emerging issues for each grid. While one jurisdiction may be more advanced in adopting certain technologies, overall there is no clear leader in smart grid development. Instead, there is a universal sense of tremendous energy and enthusiasm for modernizing the electricity system to serve the digital age. In terms of how to marshal this energy to transform the electricity system, however, the presentations contained more questions than answers. Ontario, like the other jurisdictions, has the opportunity to both lead and learn from the efforts of others as it works to create a smart grid that will benefit Ontario's people, economy and environment.

ADVANCING THE SMART GRID

The recommendations above envision action by numerous parties to develop a smart grid in Ontario. The Forum sees value in continuing to champion smart grid progress, monitor ongoing developments and advocate common approaches where they make sense. To this end, the Forum believes that an enduring organization to promote smart grid development with a broader base of representation may be appropriate in the future. The Forum will consider this further based on insights gathered from discussions with Government and industry following the release of our report. As part of this consideration, the Forum welcomes feedback and ideas on how to move forward.

Appendix A – Presentations with Links and Additional Information Resources

1.0 VISION

Overview of SmartGrids – European Technology Platform: Dr. Christian Sasse, Tavrida Electric North America Inc.: http://www.ieso.ca/imoweb/pubs/smart_grid/SmartGrids_Ontario_CSasse.pdf

Ontario Smart Grid Forum: Peter A. Landauer, Capgemini North America: http://www.ieso.ca/imoweb/pubs/smart_grid/IESO_Smart_Grid%20_PLandauer.pdf

2.0 CONSUMER FOCUS

Plugging in the Consumer – Innovating Utility Business Models for the Future: Michael Valocchi, IBM Global Services: http://www.ieso.ca/imoweb/pubs/smart_grid/Plugging_in_the_Consumer-IBM.pdf

Day In The Life Of a Utility Customer: Tom Brunetto, Distributed Energy Financial Group (DEFG LLC): http://www.ieso.ca/imoweb/pubs/smart_grid/Day_in_the_Life-DEFG.pdf

Bell Canada Home Energy Management: Tom Hewitt, Bell Canada: CONFIDENTIAL PRESENTATION AND DEMONSTRATION

A Smart Energy Ecosystem: Scott Stewart, Direct Energy: http://www.ieso.ca/imoweb/pubs/smart_grid/Direct_Energy-Smart_Grid_Forum.pdf

Consumer Positions and Attitudes: Raed Abdullah, Hydro Ottawa: http://www.ieso.ca/imoweb/pubs/smart_grid/HydroOttawa-Consumer_Focus.pdf

3.0 ONTARIO STATUS UPDATE

Connectivity: the Key to the Smart Network: Richard Bertolo and Leonard Gross, Hydro One Networks: http://www.ieso.ca/imoweb/pubs/smart_grid/HydroOne-Connectivity.pdf

Toronto Hydro and the Emerging Smart Grid Infrastructure: Joshua Wong, Toronto Hydro: http://www.ieso.ca/imoweb/pubs/smart_grid/THESL-Infrastructure.pdf

MDM/R Status Update and Plans: Bill Limbrick, IESO: http://www.ieso.ca/imoweb/pubs/smart_grid/IESO-MDMR-Update.pdf

Smart Grid... Realizing the Promise: Edward Chatten, PowerStream Inc.: http://www.ieso.ca/imoweb/pubs/smart_grid/PowerStream.pdf

Current Status and Investment Plans: David Curtis, Hydro One Networks; John Mulrooney, PowerStream; Joshua Wong, Toronto Hydro: http://www.ieso.ca/imoweb/pubs/smart_grid/Current_Status_and_Investment_Plans.pdf

Status of Hydro Ottawa's Smart Grid Programs and its Implications for the Smart Grid: Raed Abdullah, Hydro Ottawa: http://www.ieso.ca/imoweb/pubs/smart_grid/HydroOttawa.pdf

Smart Grid I The Regulatory Perspective: Mark Garner, Ontario Energy Board: http://www.ieso.ca/imoweb/pubs/smart_grid/OEB-SmartGrid-The_Regulatory_Perspective.pdf

4.0 DISTRIBUTION

Smart Grid to Provide Capacity Relief to Distribution Utilities: Jim Blackman and M.L. Chan, Quanta Technology, LLC: http://www.ieso.ca/imoweb/pubs/smart_grid/Quanta_Technology.pdf

CURRENT Smart Grid Overview: Daniel Ripchensky, Current Group, LLC: http://www.ieso.ca/imoweb/pubs/smart_grid/CURRENT_Group_Presentation.pdf

EDA's Vision: Local Distribution Utilities' Future Role in Building the Sustainable Communities of Tomorrow: Bryan Boyce, Electricity Distributors Association; David Collie, Burlington Hydro; Michael Angemeer, Veridian Corporation; Bill Hawkins, Electricity Distributors Association: http://www.ieso.ca/imoweb/pubs/smart_grid/EDA.pdf

5.0 DISTRIBUTED ENERGY RESOURCES

Distributed Energy: Paul Shervill and Kevin Devitt, Ontario Power Authority: http://www.ieso.ca/imoweb/pubs/smart_grid/OPA-Distributed_Generation.pdf

Presentation to Smart Grid Forum: Colin Clark, Brookfield Power Corporation: http://www.ieso.ca/imoweb/pubs/smart_grid/Brookfield-Smartgrid.pdf

DG Integration Key to Smart Grid: Ravi Seethapathy, Hydro One Networks: http://www.ieso.ca/imoweb/pubs/smart_grid/HydroOne-DG.pdf

Demand Response: Dan MacDougall, Rodan Energy and Metering Solutions, Inc.: http://www.ieso.ca/imoweb/pubs/smart_grid/MacDougall-Rodan.pdf

Farm Biogas – Cogeneration in Ontario: Aidan Foss, ANF Energy Solutions Inc.: http://www.ieso.ca/imoweb/pubs/smart_grid/Aidan_Foss-Farm_Biogas_Cogeneration_in_Ontario.pdf

6.0 MICRO-GRIDS

The Smart MicroGrid Revolution: Kurt Yeager, Electric Power Research Institute (EPRI) and Galvin Electricity Initiative: http://www.ieso.ca/imoweb/pubs/smart_grid/KurtYeager-EPRI.pdf

Energy Hub Management System: David Curtis, Hydro One; Dr. Ian Rowlands, University of Waterloo: http://www.ieso.ca/imoweb/pubs/smart_grid/UW-H1_Rowlands-Curtis.pdf

7.0 ELECTRIC VEHICLES

Electric Vehicles and the Grid: Arindam Maitra, Electric Power Research Institute (EPRI): http://www.ieso.ca/imoweb/pubs/smart_grid/ArindamMaitre-EPRI.pdf

Plug-in Electric Vehicles – Standards: Tom Odell, General Motors of Canada: http://www.ieso.ca/imoweb/pubs/smart_grid/GM-TomOdell.pdf

Better Place – Introduction: Sean Harrington, Better Place: CONFIDENTIAL PRESENTATION

8.0 STORAGE, STANDARDS AND SECURITY

An Overview of Smart Grid Standards: Grant Gilchrist, EnerNex Corporation: http://www.ieso.ca/imoweb/pubs/smart_grid/Gilchrist-EnerNex.pdf

Cyber Security and the Smart Grid: Doug Westlund and Peter Vickery, N-Dimension Solutions Inc.: http://www.ieso.ca/imoweb/pubs/smart_grid/N-Dimension.pdf

Electricity Storage: A Multi-valued Technology Opportunity: Rob Brandon, Natural Resources Canada: http://www.ieso.ca/imoweb/pubs/smart_grid/NRCAN-Brandon.pdf

9.0 TRANSMISSION

Context and Candidate Outcomes to Shape North American Electric System Transformation: Carl Imhoff, Pacific Northwest National Laboratory: http://www.ieso.ca/imoweb/pubs/smart_grid/PNWL-Carl_Imhoff.pdf

10.0 THE CASE FOR ONTARIO

Value Proposition and Drivers for Change – The Case for Ontario: Helen Lainis, IESO: http://www.ieso.ca/imoweb/pubs/smart_grid/IESO-The_Case_for_Ontario-Transmission.pdf

11.0 TECHNOLOGY COMPENDIUM

Smart Grid – Technology Status and Prospects: Lisa Dignard-Bailey, Natural Resources Canada: http://www.ieso.ca/imoweb/pubs/smart_grid/NRCan_Technology_Status_and_Prospects.pdf

ADDITIONAL SOURCES OF SMART GRID INFORMATION

GRID 2030 – A National Vision for Electricity's Second 100 Years: United States Department of Energy: http://www.ieso.ca/imoweb/pubs/smart_grid/DOE_Grid_2030.pdf

U.S. Department of Energy Office of Electricity Delivery and Energy Reliability: http://www.oe.energy.gov/smartgrid.htm

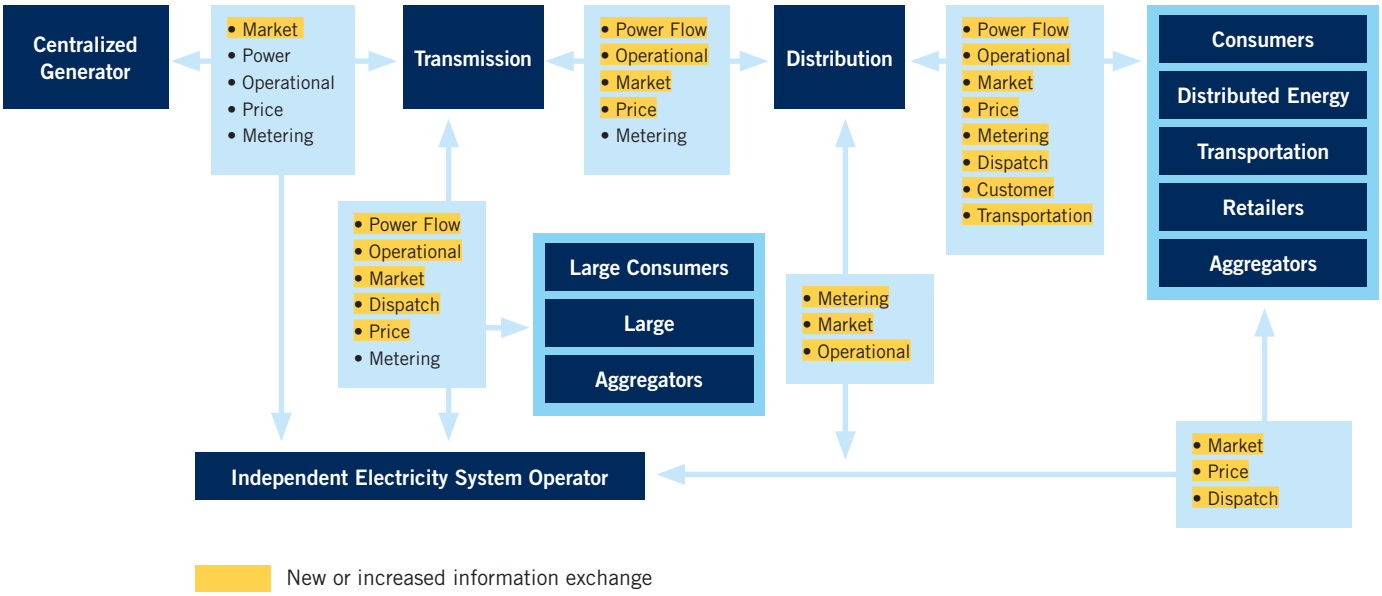
Congressional Research Service, Smart Grid Provisions in H.R. 6, 110th Congress: http://www.fas.org/sgp/crs/misc/RL34288.pdf

European SmartGrids Technology Platform – Vision and Strategy for Europe's Electricity Networks of the Future: European Commission, European Union: http://www.ieso.ca/imoweb/pubs/smart_grid/EU_Smartgrids_Visison_and_Strategy.pdf

Smart Grid Newsletter: http://www.smartgridnews.com/

U.S. DOE Smart Grid Primer: http://www.oe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages.pdf

Appendix B – Information Exchange for Coordinating Smart Grid Operation



- The above diagram illustrates the need for increased coordination amongst the divisions of the electricity system to enable effective smart grid operation, enabled through new or increased information exchange.
- This coordination is characterised by the bi-directional flow of information, shared functional objectives, enabling of cross-boundary benefits, and mutual cooperation and support.
- The information exchanged may include:
  - Power Flow – voltage, frequency, phase, load flow, losses, outages status, power quality
  - Operational Information – protection, control, system state, supply and demand, weather, spare capacity, short circuit levels, planned outages, islanding control, time-to-restoration
  - Dispatch – control signals for dispatching generation and load
  - Market Information – generation mix, reserve capacity
  - Price – price of electricity, rates, connection costs, tariffs
  - Metering – interval metering, meter data management
  - Customer – billing, home device control, carbon footprint, choices/overrides, consumption history, call centre, utility programs/offers, demand response, behind-the-meter generation control
  - Transportation – plug-in hybrid vehicle (PHEV) control, vehicle-to-grid (V2G) control, managing intermittent demand

To contact a Forum member call the Independent Electricity System Operator
655 Bay Street, Suite 410
P.O. Box 1
Toronto, ON M5G 2K4
www.ieso.ca

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca






Filed: October 19, 2009
EB-2009-0096
Exhibit H-13-16
Attachment 2
Page 1 of 19

Hydro One

Smart Meter / Smart Grid Progress

April 2009

Who are we

Transmission:

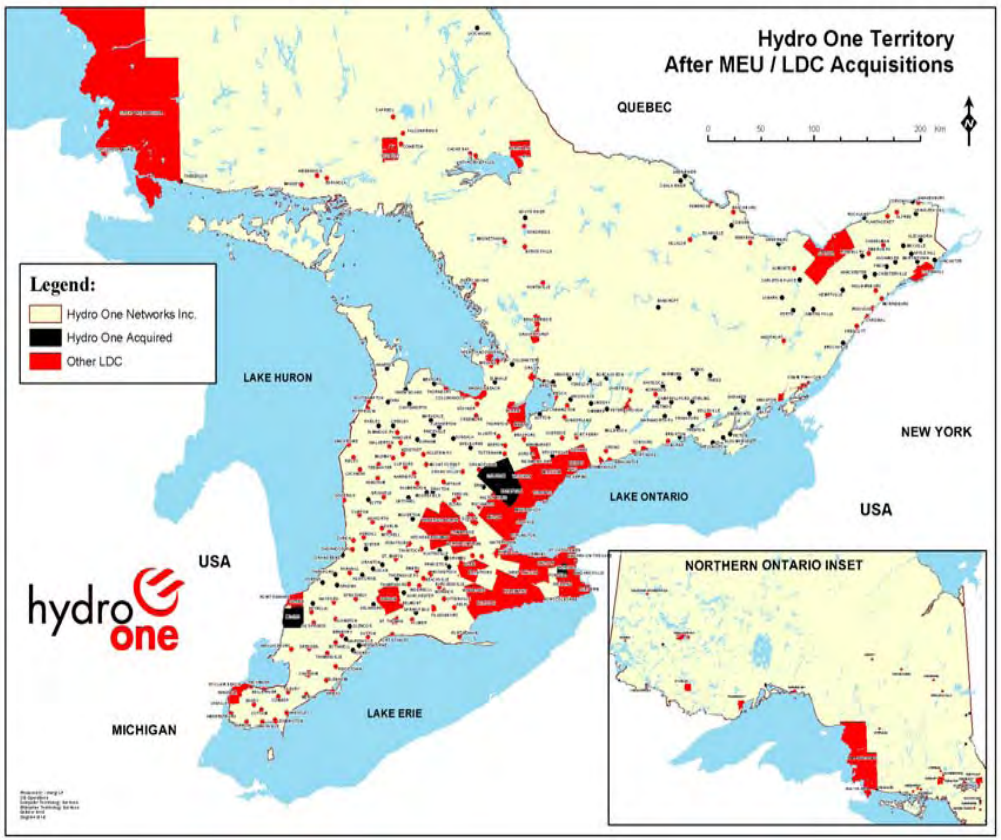
28,600 (circuit - km) interconnected

85,000 towers, 4000 km fibre

Peak demand: 27,005 MW

Energy transmitted: 157 TWh





Distribution:

123,000 km of distribution lines,

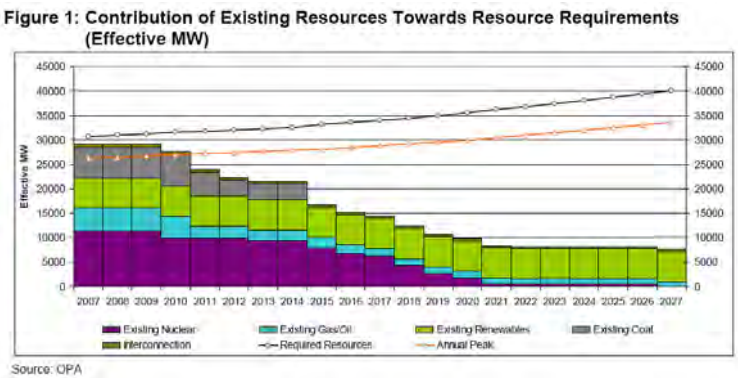
1.8M poles, 1.3M customers,

640,000 sq km service territory **(twice the size of Texas),** acquired 90 utilities since 2000

(still about 90 utilities left)

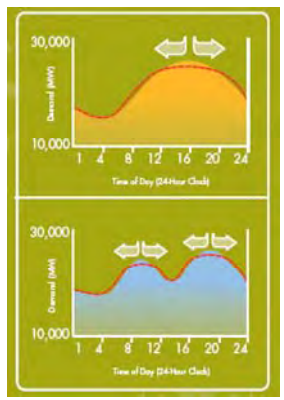
Ontario Ministry of Energy Direction

- Create an energy conservation culture across Ontario and help consumers better manage their electricity use
  - More efficient use of Ontario's existing supply
  - Reduce reliance on external generation resources
  - Need to replace 80% of generation over next 20 years (~$70B)
- Install 800,000 smart meters in Ontario by Dec. 2007– convert 100% to smart meters by 2010



Summer Peak

Winter Peaks



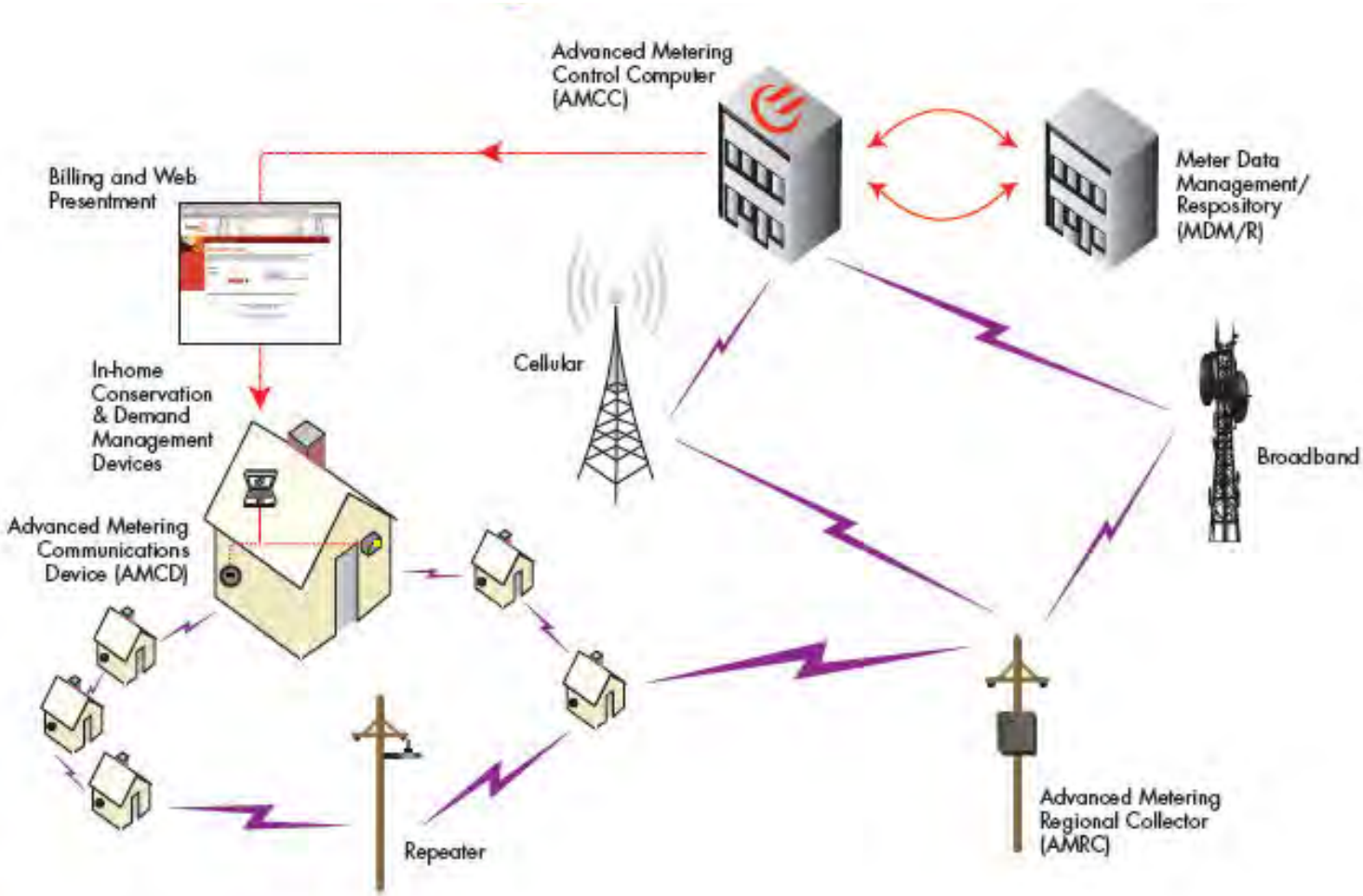


What have we done

- Deployed 810,000 smart meters since end of 2006
  - Tested AMI communication in “in situ” lab, urban and rural
  - Automated change meter order process
  - GPS / Geo-code
  - Deployed a community (15k in 2006), tested processes and communications
- Network build for 400,000
- Using AMI for AMR
- In process of CIS upgrade and MDMR Integration

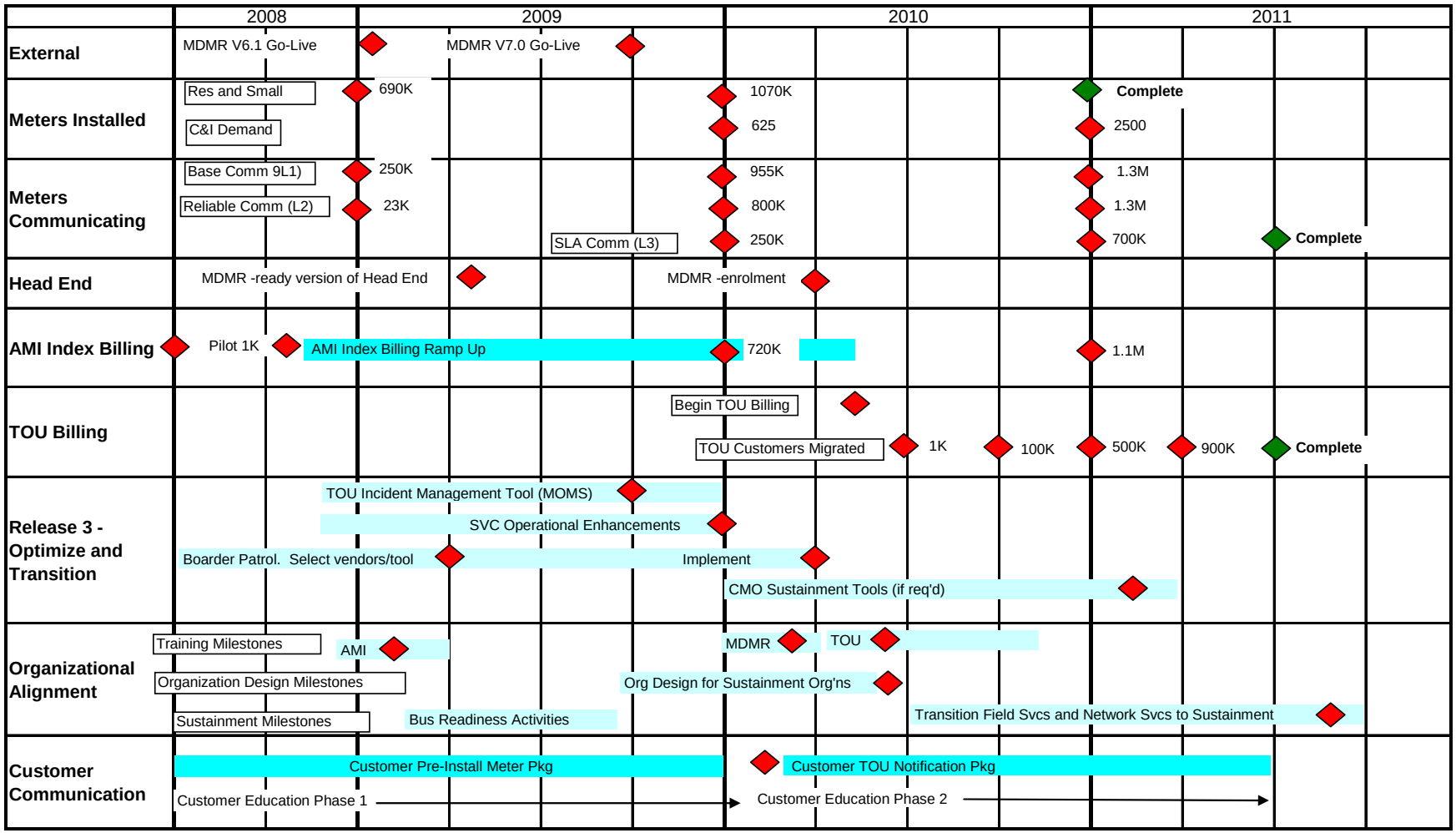


Smart Metering System



smart meter project

Smart Meter Project Timeline



Where are we going

Deploy a smart metering/network solution that meets the Ministry of Energy's requirements at the lowest possible cost and is an enabler for other business processes and transformations:

IP / Standards / Secure / Open, non-proprietary – the foundation

2005 BCS / Architecture

Smart Meter Minimum Requirement

Smart Network – Utility Requirements

Third Party

Basic

- AMR
- kWh, kW, kVA
- Outage Detection
- Meter Management
- Real-time Outage Management

Basic + In-home Services

- Remote Disconnect Connect
- Load Limiting
- Theft Detection
- *Load Control*
- *In-home display*
- *Multi-Utility AMR*
- *LDC AMR*
- *Home Security*

Basic + In-home Services + Hydro One Backhaul

- Power Quality
- Feeder Analysis
- Station Monitoring SCADA
- Office Backhaul
- DG

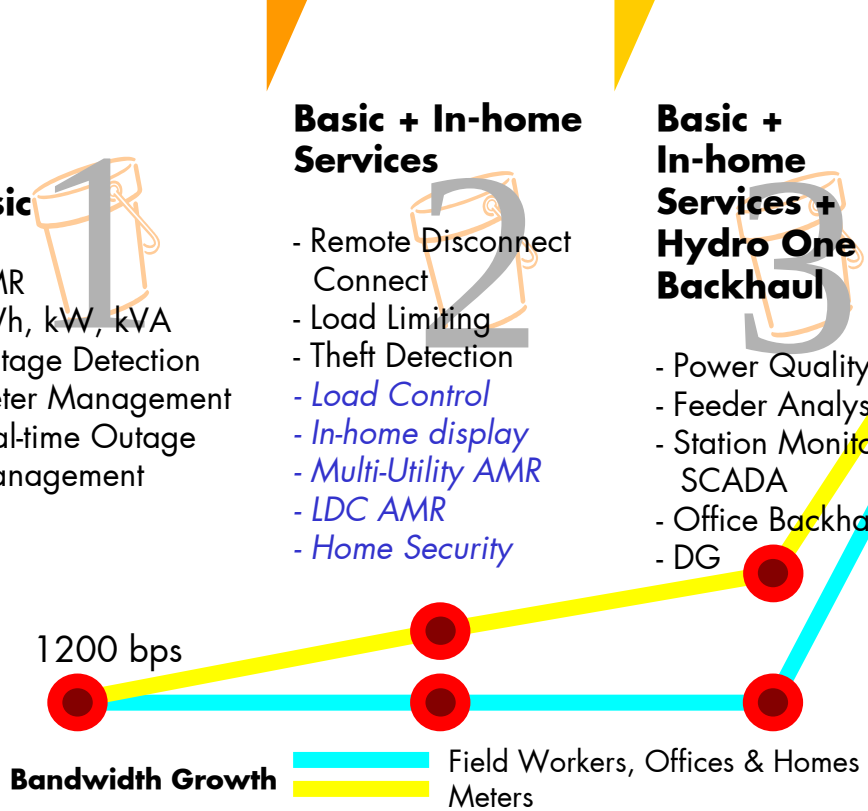
Basic + In-home Services + Hydro One Backhaul + Mobile Office

- Mobile Dispatch
- Mobile Time Reporting
- Mobile Accomplishment Reporting
- Mobile Asset Condition & Defect Reporting
- Safety Monitoring
- Fleet Management
- Asset Security
- Cellular – Paging – Email
- Optimized Dispatch
- Automated Map Updates

Basic + In-home Services + Hydro One Backhaul + Mobile Office + Rural Broadband

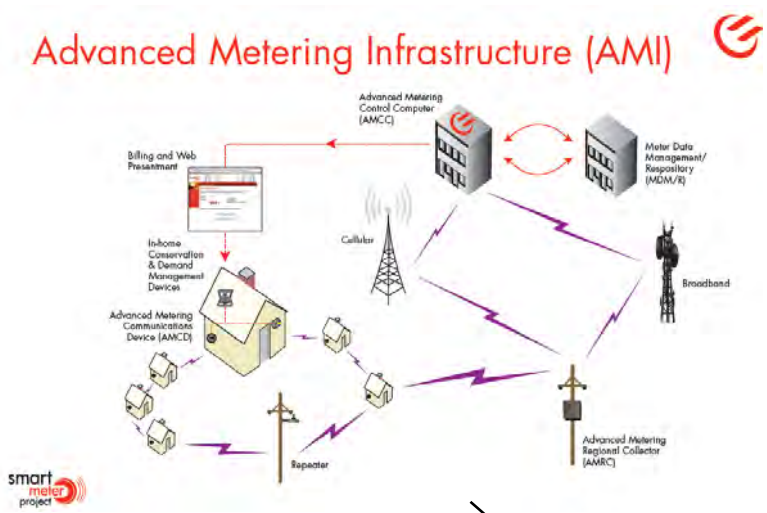
- *Residential Broadband*
- *MUSH Broadband*

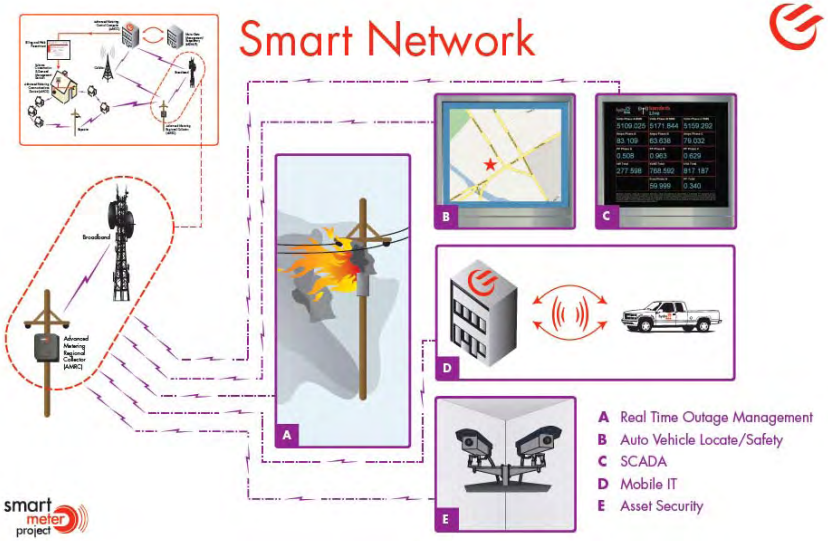
***Value Added Services*

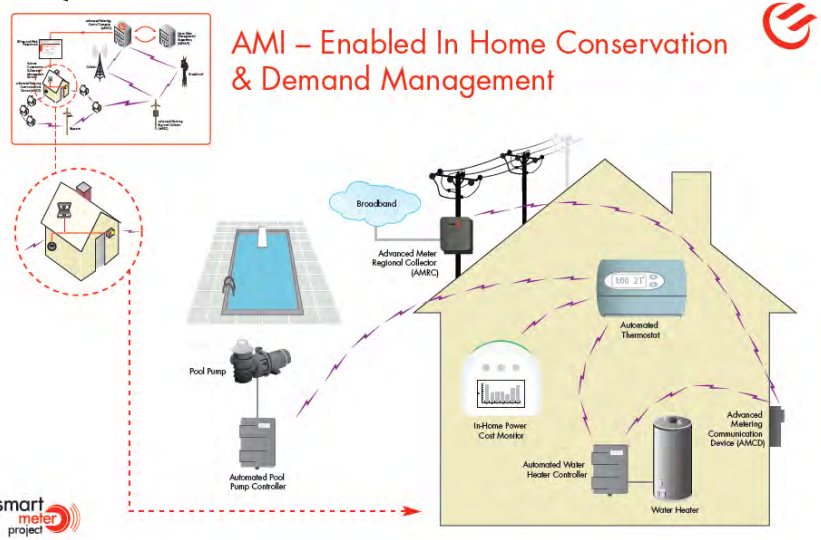


Δ Benefit > Δ Cost by 3:1 for Utility applications and (level 4)

Architecture - Leveraging AMI Infrastructure







- ✓ Vision / BCS
- ✓ POC
- • Plan →Pilot

Key Value Release Functions

Proved the concept



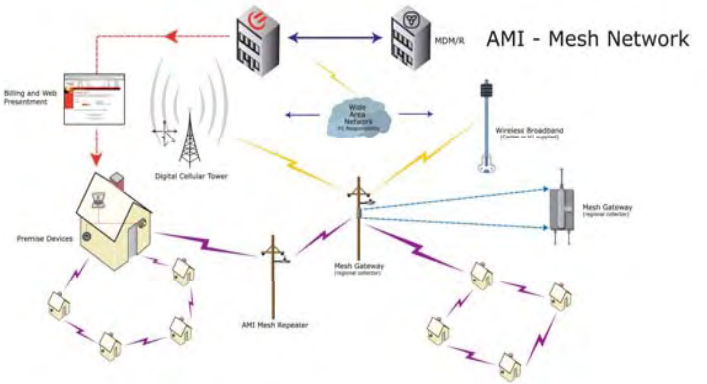
Asset Security



Mobile IT

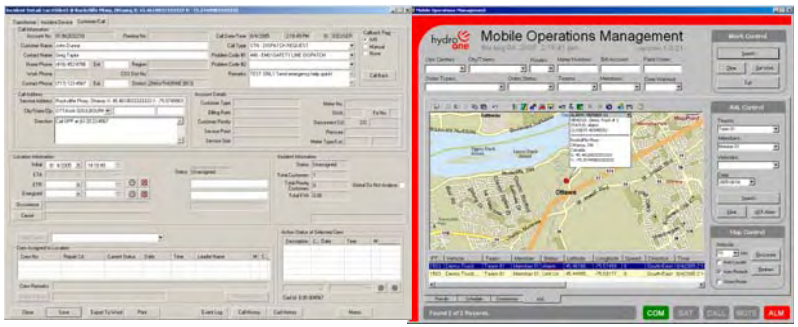


SCADA





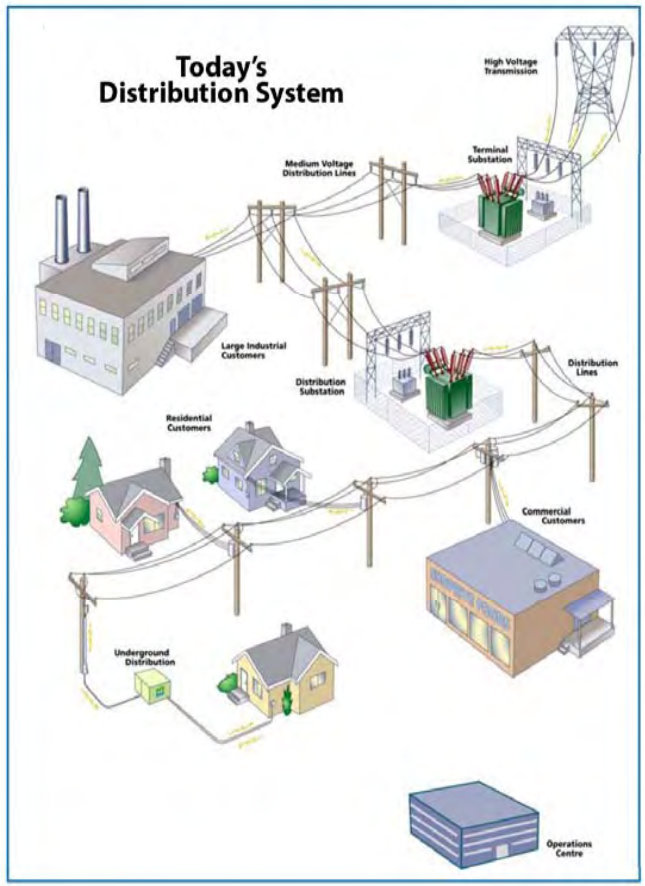
Rationalize Communications Network

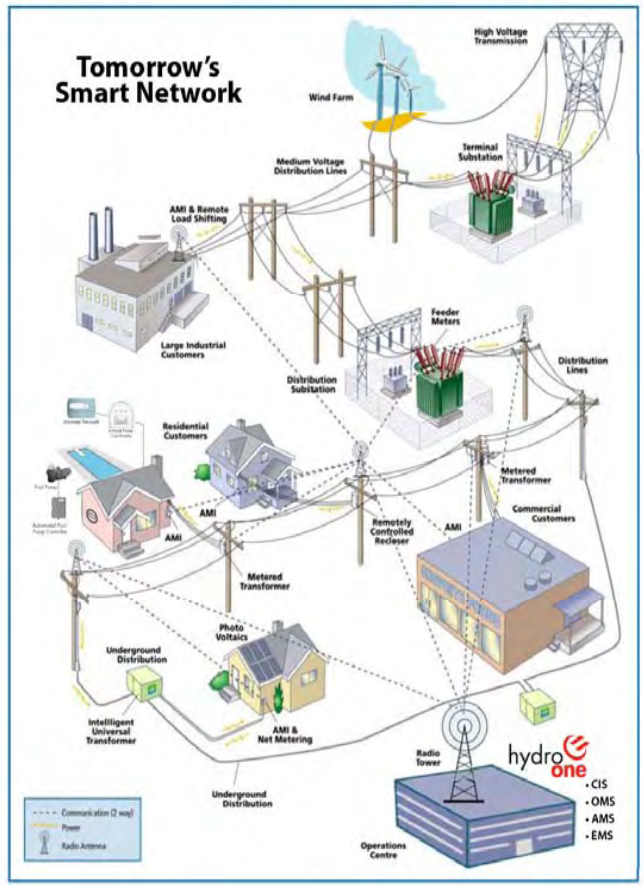


AVL/Safety

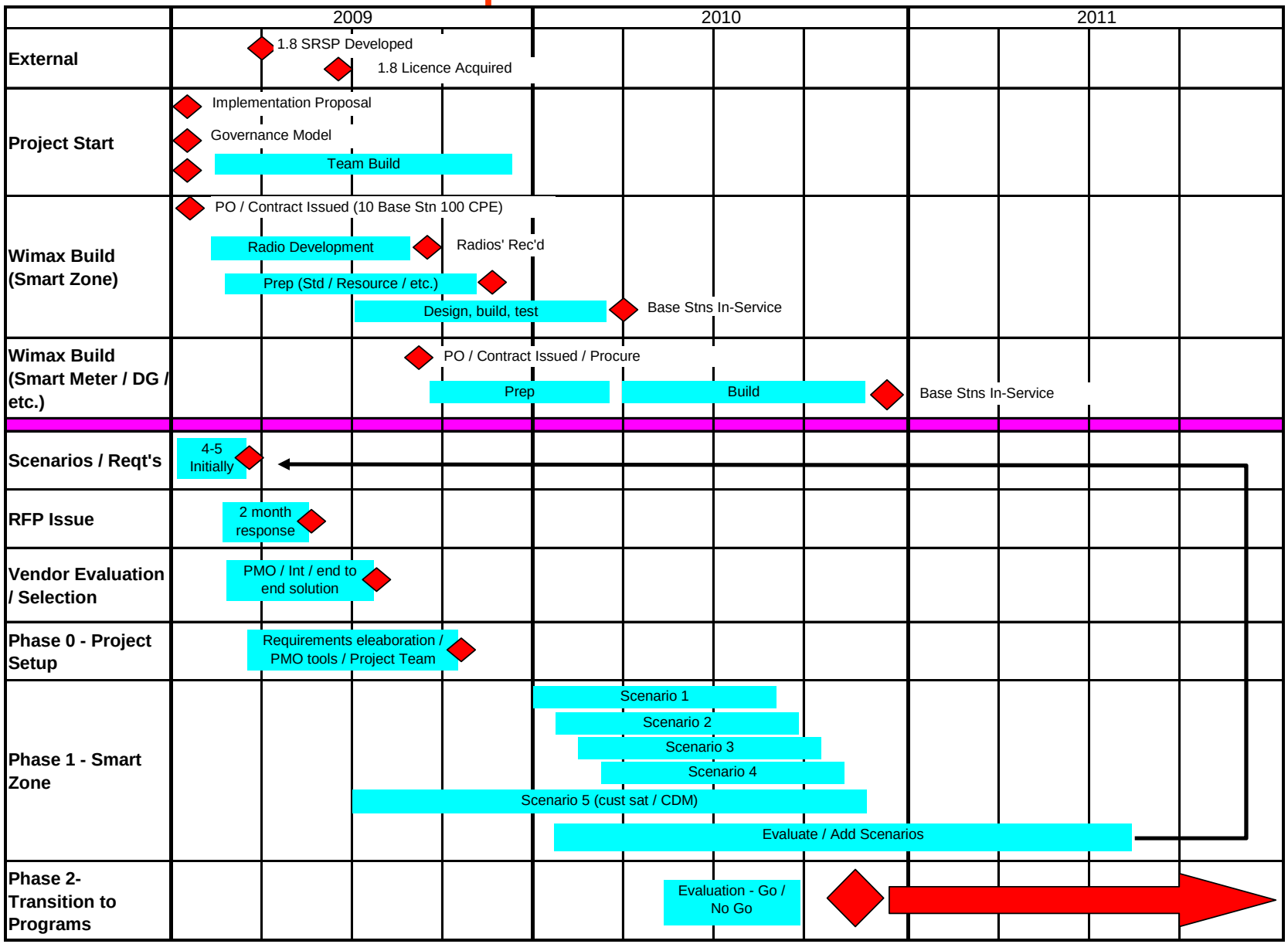
2009 – “Smart Grid” Implementation

Immediate
<u>Horizon:</u>
-WAN Build
-RFP
-Project Setup
-Smart Zone
-Programs





Smart Grid Project Timeline

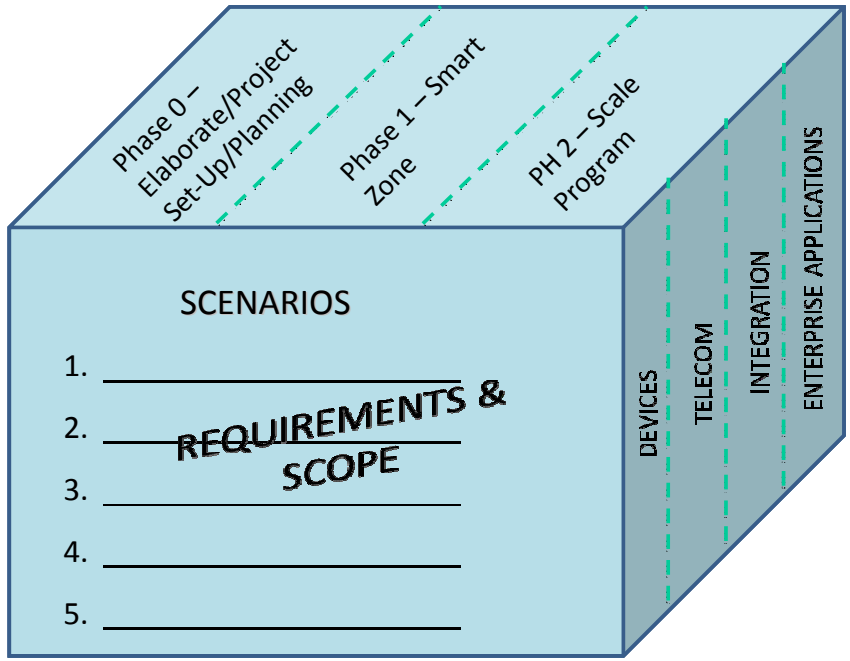


1800-1830 MHz!

- Industry Canada has issued a Policy Directive in December…key milestone to moving forward.
  - Consultation Occurred, no issues
- SRSP now in the hands of RABC
- Technical Spec finalized probably end of Q1
- Licence by Q2
- Wimax at 1800 MHz development lead time is expected to be 6-9 months.
- Initial vendor selected and development underway

RFP Process

- Modelled on the 2005 Smart Meter RFP
  - Scenarios / Requirements
  - Solution components
  - Timeline / Phases
- Best of breed or Integrator
  - Field devices
  - Telecommunications
  - COTS / EA
  - Integration
  - Various SMEs
- Phase 0 = plan
- Phase 1 – Joint opportunity / incubate in Smart Zone Sandbox
- Phase 2 – Transition to programs

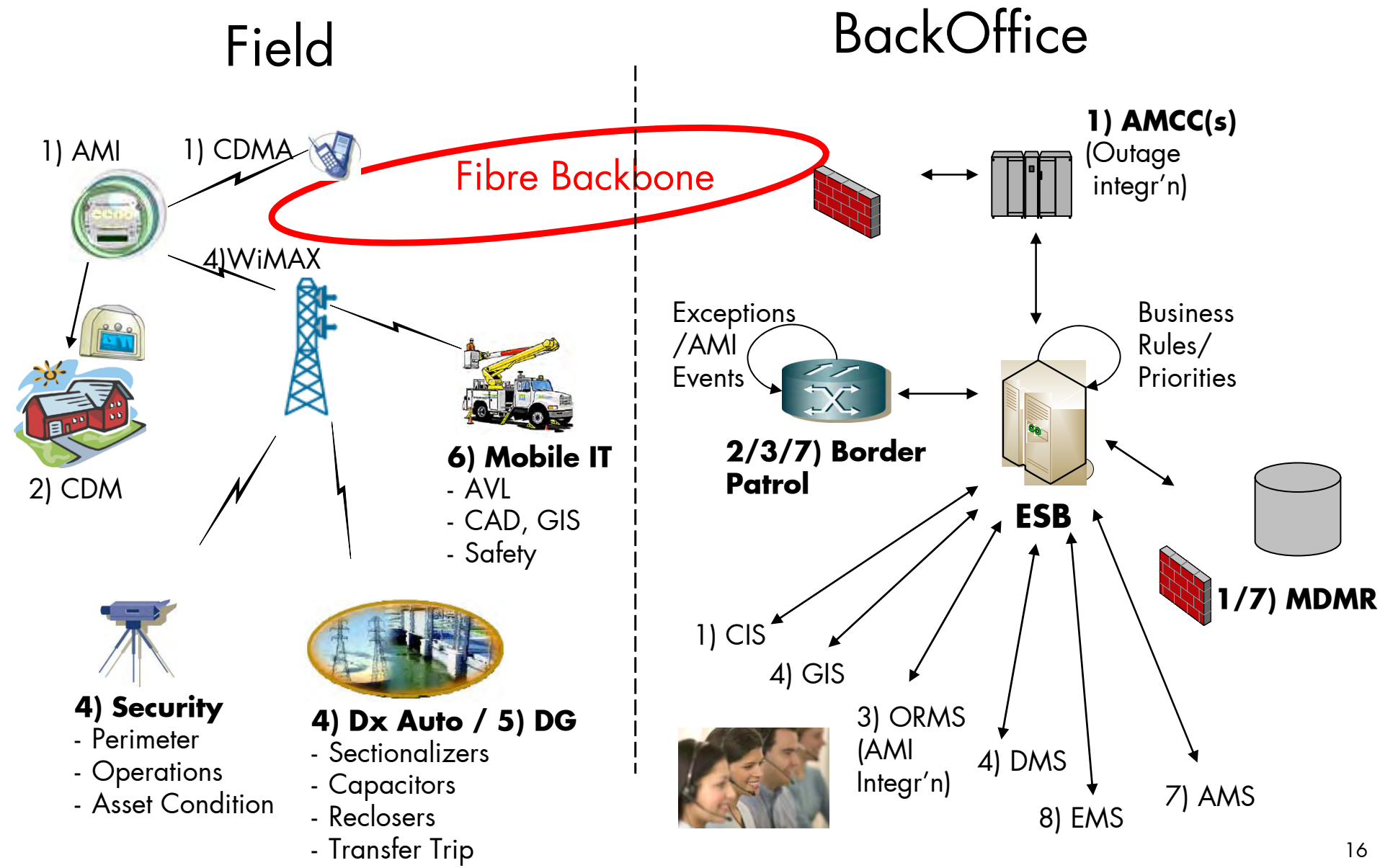


Business Scenarios

SCENARIOS:	Aligns with Gov't Policy	Enhances Worker / Public Safety	Increases Customer Sat - Reliability	Increase Customer Sat – Bill Managed	Positive ROI Impact	Technology Risk (maturity, complexity, standards)
1. DG Integration	●	●	●	●	◉	○
2. Outage Restoration Optimization	◉	●	●	◉	◉	◉
3. Dx Reliability-Operations Improvement	◉	●	●	◉	●	◉
4. Dx Network Planning Tools	●	●	●	◉	●	●
5. Customer Enablement	●	◉	●	●	◉	○
6. Telecommunication Optimization	◉	●	◉	◉	●	◉
7. Work Safety / Lone Worker	◉	●	◉	◉	◉	◉
8. Asset Security	◉	●	●	◉	○	◉
9. PHEV Integration	●	○	●	●	○	○
10. PHEV H1 Usage	●	○	○	○	◉	○
11. Dx Reliability Asset Management	◉	◉	●	◉	●	◉
12. Off Peak Volt/Var control	◉	◉	◉	◉	●	◉
13. MicroGrids	●	◉	●	○	◉	○

● – High, aligns or enhance
◉ – Medium, neutral
○ – Low, does not align or detracts

Integration – key to scale and value release



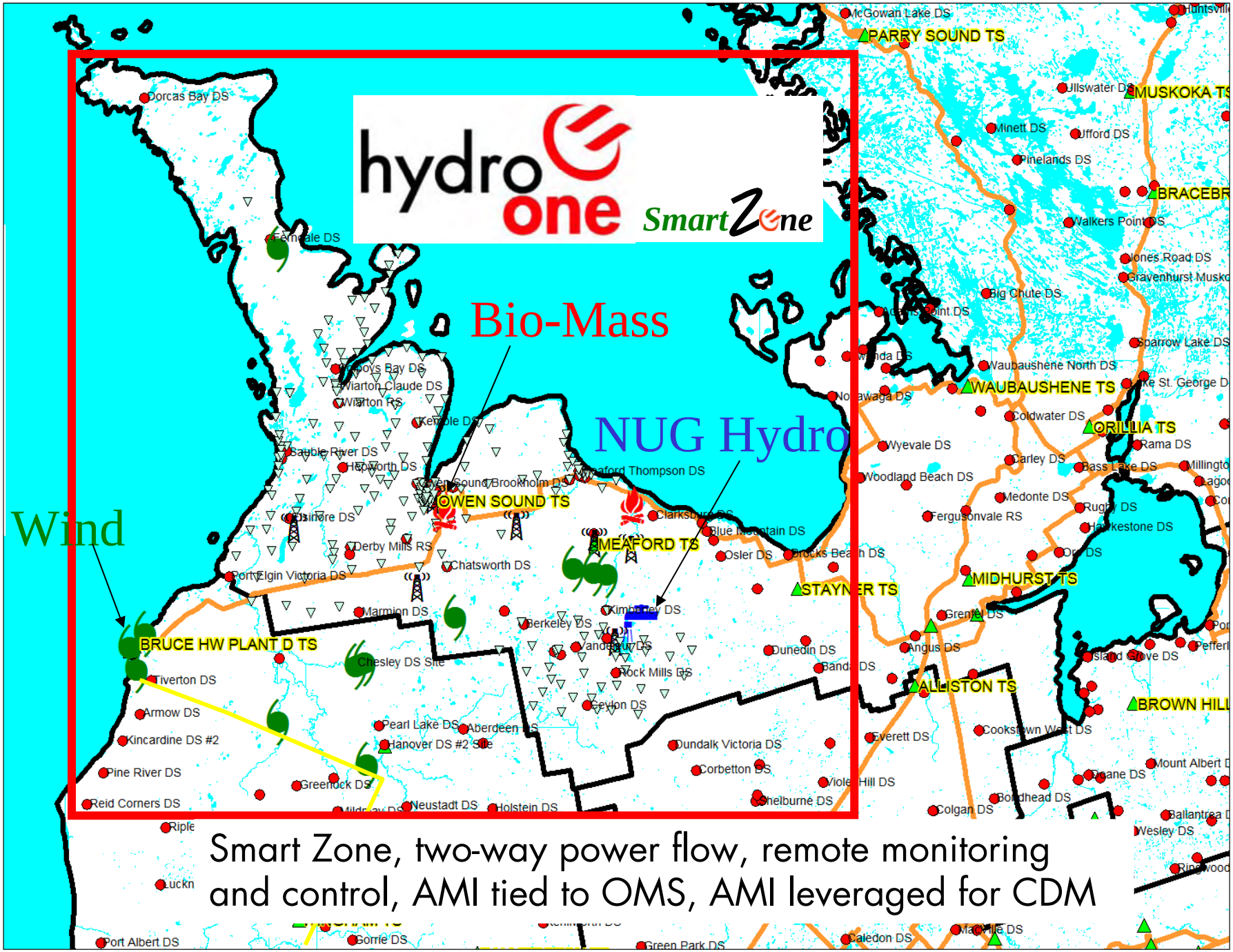
SmartZone

Owen Sound Area – Zone d'essai

- Roll out of enablers - Wimax and GIS deployment
- Realize mandated programs - CDM, Smart Meter, DG
- Technology trials – GIS mapping, IED's, Mobile IT, ORMS/OMS, Dx monitor and automation, DG SCADA, customer demand response, Energy Storage
- Develop training materials and Operating procedures

Hydro One Green Initiative

- PHEV trial in the SmartZone
- Third Party collaboration - Realize energy savings – Res/Com
- Technology trials – CDM Controllers, Smart appliance interface


hydro one
SmartZone
Bio-Mass
NUG Hydro
Wind
PARRY SOUND TS
MUSKOKA TS
BRACEBR
WAUBAUSHENE TS
ORILLIA TS
OWEN SOUND TS
MEAFORD TS
STAYNER TS
MIDHURST TS
BRUCE HW PLANT D TS
ALLISTON TS
BROWN HILL
Dorcas Bay DS
Ferndale DS
Wiarton Claude DS
Wiarton RS
Kemble DS
Sauble River DS
Hepworth DS
Owen Sound Brookholm DS
Meaford Thompson DS
Clarksburg DS
Blue Mountain DS
Osler DS
Brocks Beach DS
Derby Mills RS
Chatsworth DS
Port Elgin Victoria DS
Marmion DS
Kimberley DS
Berkeley DS
Vandeleur DS
Rock Mills DS
Ceylon DS
Dunedin DS
Banda DS
Chesley DS Site
Tiverton DS
Armow DS
Kincardine DS #2
Pine River DS
Reid Corners DS
Pearl Lake DS
Aberdeen DS
Hanover DS #2 Site
Greenock DS
Neustadt DS
Holstein DS
Dundalk Victoria DS
Corbetton DS
Violet Hill DS
Shelburne DS
Port Albert DS
Gorrie DS
Green Park DS
Caledon DS
Colgan DS
Bondhead DS
Mount Albert D
Wesley DS
Ballantrea D
Island Grove DS
Cookstown West DS
Everett DS
Angus DS
Grenfel DS
Fergusonvale RS
Medonte DS
Rugby DS
Hawkestone DS
Woodland Beach DS
Carley DS
Bass Lake DS
Rama DS
Coldwater DS
Wyevale DS
Waubaushene North DS
Sparrow Lake DS
Big Chute DS
Adams Point DS
Jones Road DS
Gravenhurst Musko
Walkers Point DS
Pinelands DS
Ufford DS
Minett DS
Ullswater DS
McGowan Lake DS
Huntsville
Smart Zone, two-way power flow, remote monitoring and control, AMI tied to OMS, AMI leveraged for CDM

Questions?


Congratulations to Hydro One!
Awarded the 2007 UPN Best Advanced Metering Initiative in a North American Municipal Utility


2008 Finalist
platts GLOBALENERGYAWARDS

Smart Grid Business Scenarios

Discussion Draft v1.0

NOTE:
This document represents a working draft of Scenario's and descriptions which may vary in the issued RFP. This document is provided for discussion purposes only.

Scenario A: DG Integration	**Requirements**
A significant amount of new generation capacity is being planned through the installation of Distributed Generation (DG) facilities on Hydro One's *distribution* system. An integrated system level view of the Protection and Control (P&C) requirements at various voltage levels is required. With Smart Grid infrastructure in place such as WiMax, IEC61850 compliant devices, etc, more "Plug and Run" solutions are possible. Maximization of renewable energy (wind/solar/hydraulic/biomass) is one of the leading objectives. To this end options to reconnect DG's automatically, transfer DG control to other feeders, to store excess DG outputs shall all form an integrated solution. All this would have to happen within the limits of power quality, voltage regulation, var support and operational standards inforce by various regulatory codes in Ontario. Therefore addition of other devices such as energy storage systems, voltage support/var support systems and dynamic controllers would, and should, now be a part of the above solution set(s). There will be a need to monitor and control intermittent resources at a group level (eg all provincial wind farms as a group). Renewable energy sources would need to be optimized based on operational needs from time to time. Algorithms for such energy source optimization will also be needed. An attempt will be made to examine the possibility of load/supply balancing in a local area to ensure its stabile operation as a standalone microgrid. This will involve the use of distributed intelligence, distributed micro controllers and control algorithms to enact changes to both the supply and demand side. Such tools could be at the utility end, at the district level, and/or at the customer level.	High level business requirements: • Remote integration, monitoring and control; adaptive protection • Degree of automation; predictive modelling • Interoperability amongst all devices • Solution based on standards and open protocols • System/Cyber Security • Scalability (50k distribution automation (DA) points, 2M meters / demand response (DR) points) • Transfer trip requirements • Distribution Station (DS) monitoring • Automated generation rejection scheme's • DG protection package • Regulator and tap changer controls • Dynamic controls • Storage integrations • Volt/var controls
Applications: This solution shall interface with existing power devices (such as breaker, regulators and reclosers), DMS/Scada controls, CDM/DR, telecommunications interfaces.	

Scenario B: Dx Reliability-Operations Improvement (OGCC Controllers)	**Requirements**
The Distribution System will be automated in varying degrees to provide for real time monitoring and control, automatic restoration and optimized operations to reduce overall utility costs and improve customer satisfaction. Within distribution stations, SCADA will be enabled with intelligent electronic device (IED) deployments on various pieces of equipment augmenting with video feeds to provide visual confirmation of perimeter and equipment alarming in stations. P&C configurations will be IEC 61850 protocol compliant which will allow for high speed deterministic protection…beyond current DNP monitoring and control abilities. Under Frequency Load Shedding (UFLS) protection for load shedding at DS's versus TS's to prevent net generation loss. Various automated field devices will also enable the following: • Volt / Var optimization will be achieved through installation of and control of capacitor banks and integration with EMS/DMS. • Remote group relay setting changes on reclosers. • Remote control of mid-feeder devices (eg. reclosers, capacitors, switches). • Design and installation of remote control of adaptive protections to allow DG connection on alternate feeds. • Installation of power quality monitors on sub-transmission (44/27.6kv feeders = "M Class") and distribution (less than 13kv = "F Class") class feeders for power quality metering. • Installation of electronic fault indicators on sub-transmission and distribution class feeders for calculation of distance to fault. • Bi-directional regulation. • Feeder analysis to ensure adequate relay coverage and voltage for any switching configurations in real time and study mode.	High level business requirements: • Remote control integration • Interface with AREVA EMS (NMS) • Real-time monitoring and control of TS, DS, RS, Line Regulators, Inline Reclosers, Remote Control Switches (Motorized HVI), Capacitors, fault indicators, instrument transformers for line segment loading. • Volt/Var Optimization • Interoperability amongst all devices • Solution based on standards and open protocols • Scalability (50k DA points, 2M meter / DR points) • Improved SAIDI/CAIDI/SAIFI • Meets NERC requirements where required. • Visual Realization (ie. Wide area visualization of the network, installation of video cameras at stations)

To enhance operator control 2 way conversion of DS data to schematic GIS is required as well as situational awareness by wide area visualization.	
Applications: This application shall interface with stations monitoring/control/automation devices (i.e. voltage regulators / capacitors, temperature/vibration), telecommunications, EMS, GIS, AMI / Operational data store, Enterprise Asset Management.	

Scenario C: Outage Restoration Optimization (Field Focus)	**Requirements**
Customer outage duration will be minimized by leveraging Scenario B station/lines automation with quicker more efficient fault restoration by enhancing field force mobilization. Outage Management will begin with integration of various enterprise systems (eg SCADA, GIS, AMI, CIS, WFM, OMS and customer portal). These interfaces will be utilized to enable efficient business processes. SCADA will interface with OMS to identify sustained interruptions and reconcile on restorations via normal and alternate switching configurations. Mapping and Dx device connectivity will be GIS based and near real-time. AMI and feeder device (eg bellwether meters, fault indicators) events and data will be garnered over the extended wireless and communication network. Filtering and analysis of all AMI and Feeder Device data and events will be done to confirm forced outages and to throttle data in high volume times, then delivered to OMS. There will be a bidirectional interface with OMS and capability to query and ping AMI devices and other network equipment. The OMS and AMI operator will be able to distinguish and indicate if there is a communication network issue or a power network hierarchy issue. Field forces location will be known by GPS coordinates and viewed on a geographic display. Lone worker personal devices will be worn outside of vehicles and location will be known and displayed. Distress signal from PDA will alert at the OGCC. Crews will be dispatched by proximity/availability/skill set. Via WFM, crew demand work (currently WEP CAD) and trouble work (currently ORMS CAD), GIS maps and restoration status will be enabled. OMS Operators and AMI operators will have access to view demand and trouble work. Accomplishment reporting, time reporting, trouble sheet reporting, asset and material update in SAP will be executed in near real time via WFM. Upon restoration the system will confirm restoration of all downstream points. In parallel customers will be notified of outage status and details through a variety of media (eg IHD / IVR/	High level business requirements: • Improved SAIDI/CAIDI • Scalability to 2M points, province wide • Higher level of productivity • Improved worker safety through AVL • System security • Solution based on standards and open protocols • Interface with CGI OMS (ORMS) • Interface with SCADA • Interface to CIS, WEP, E-customer • Improved customer awareness and satisfaction

e-customer, etc). Both real time and historic data will be used for business reporting and analytics. Ad-hoc and canned reporting will include analytics of power quality, theft of power, feeder performance and to trouble shoot outage inquires.	
Applications: This solution shall interface with telecommunication networks, CGI OMS system (ORMS), AREVA EMS system (NMS), Enterprise Service Bus (iHub), AMI, Operational data store, Reporting tools, WFM, SAP and GIS.	

Scenario D: Dx Network Asset Planning and Tools	**Requirements**
The Distribution System will be automated in varying degrees to provide for real time monitoring and control, automatic restoration and optimized operations to reduce overall utility costs and improve customer satisfaction. An operational data store will capture power quality information to provide for preventative distribution maintenance program development. Automate the process of planning (network modeling and design) to provide for better analytics that feed well established Distribution Capital (capacity) and maintenance programs: • Dx feeder connectivity model and characteristics are available in a spatial representation (ie GIS) • be combined with station and feeder electrical data store - NMS electrical data store (voltage, current, Power Factor) • Reconcile/forecast AMI system electrical data with NMS information. • Asset Management Planning including optimization failure management and reliability/predictive maintenance	High level business requirements: • Single system of record / CIM compliant • Integration of feeder operating statistics, feeder electrical data store and feeder spatial characteristics • Increased productivity • Ad hoc data query / planning • Remote integration and control • Archival data from Real-time monitoring and control of TS, DS, RS, Line Regulators, Inline Reclosers, Remote Control Switches (Motorized HVI), Capacitors, instrument transformers for line segment loading, with archiving for near term/long term planning • Meets NERC requirements
Applications: The solution must interface with Distribution planning tools (i.e. CYME network analysis software,), GIS, stations monitoring/control devices (i.e. voltage regulators / capacitors, temperature/vibration), telecommunications, distribution management system, AMI / Operational data store, Enterprise Asset Management and SAP.	

<table>
<tr><th>Scenario E: Customer Enablement</th><th>Requirements</th></tr>
<tr><td>Customers will begin migration to Time Of Use (TOU) rates beginning in early-2010. Tools / devices and information will be made available to customers to provide them better understanding, and opportunity to better control/manage, their electrical consumption. Improving customer satisfaction with regard to overall conservation targets is a key driver and innovated means to achieve this end are sought.

With evolving programs there is a need to confirm the capabilities of the AMI system in conjunction with TOU and a number of Conservation and Demand Management (CDM) options. As such there is a need for:
Broad array of technology/products including, but not limited to, two-way communicating programmable thermostats and in-home displays
Use of in-home devices (IHD) for CDM and planned outage/other notifications
Web/local presentment of information and central / utility or customer control/maintenance of devices
the ability to monitor and assess customer response to and acceptance of these devices
effective distribution channels and provisioning of devices</td><td>High level business requirements:
Simple user interface
Customer access via subscription to both push (e.g. PDA) and Pull (e.g. web portal)
Scalability to 2 million customers/5 million points, province wide
Interoperability of systems
End point devices based on standards and open protocols
System and device security
Remote maintenance/operation of deployed devices/data via appropriate head end system(s)</td></tr>
<tr><td colspan="2">Applications:

This solution shall interface with telecommunications, AMI / Operational data store, Web Presentment tools, CDM devices and control software, CIS, OMS and CRM.</td></tr>
</table>

Scenario F: PHEV	**Requirements**
The advent of Plug In Hybrid Electric Vehicles (PHEV's) will cause utilities to not only address infrastructure modifications but also to potentially widen its relationship with its customer base. Hydro One operates in both a very urban setting (via Hydro One Brampton) and the traditional rural distribution areas it has served for well over a hundred years. This Scenario will focus on the impact of PHEV's on: 1. Fleet Management a. Lowering overall carbon footprint b. Using less fuel c. Reducing noise pollution 2. Enablement of consumers to use PHEV's via: a. In-home load prioritization and management b. 3rd party contractor engagement c. ESA certification d. Utility notification of intent to purchase so the utility can manage load/infrastructure impact 3. Utility Network Impact a. Both rural and urban system impacts due to PHEV proliferation b. customer transformer / Ds / Ts system modifications requirements c. phase balancing	High level business requirements: • Solution based on standards and open protocol • Interoperability of systems
Applications: The solution must interface with AMI / Operational data store, Electrical Safety Codes and the various industry charger characteristics.	

Canadian Manufacturers & Exporters (CME) INTERROGATORY #17 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: Exhibit A, Tab 14, Schedule 2, page 30 of 34

CME notes that Hydro One's CDM Plan is premised on the assumption that the OPA will continue to fund CDM externally through the GAM. If CDM is no longer externally funded, will Hydro One continue to deliver CDM programs? If not, why not? If so, will Hydro One's CDM programs, and the costs that flow therefrom, be subject to a separate proceeding?

Response

Hydro One believes that those who benefit from CDM programs should pay the cost of CDM programs. Since the primary benefit of CDM programs is the avoided cost of generation, all customers benefit and all customers should pay. Global adjustment is the mechanism whereby all customers can pay for CDM programs. The LDC fund administered by the OPA is paid for by Global adjustment and the GEGEA anticipates a process whereby distributors will be able to receive approval from the Board for CDM programs to be funded by Global adjustment via the IESO. Hydro One expects to access both the current LDC fund administered by the OPA and to seek approval from the Board

for CDM programs to be funded by Global adjustment via the IESO once the Board has established a process for doing so.

If CDM were no longer externally funded, Hydro One's expectation is that it would continue to deliver some CDM programs, subject to OEB approval. The screening process would remain one of assessing whether or not the benefits received by those paying for the CDM programs exceeded the costs they would have to pay. Since the full cost of programs would shift to Hydro One customers in this scenario, Hydro One would only offer programs for which the benefits to Hydro One customers exceeded the cost to Hydro One customers. Hydro One would follow whatever process the Board established for the approval of these costs in rates.

Canadian Manufacturers & Exporters (CME) INTERROGATORY #18 List 1

Interrogatory

Issue 9.1 **Does Hydro One's Green Energy Plan meet the Board's filing guidelines and the objectives set out in the Green Energy and Green Economy Act, 2009?**

Issue 9.2 **Has Hydro One appropriately addressed the Green Energy Plan expenditures in the context of its overall Capital and O&M budgets?**

Issue 9.3 **Is Hydro One's methodology for allocating Green Energy Plan O&M and Capital costs between the OPA (Global Adjustment Mechanism) and Hydro One appropriate?**

Issue 9.4 **To what extent should the Board approve any projects or expenditures relating to the Green Energy Plan that are scheduled to occur beyond the test years (i.e. 2010 and 2011) in the current application?**

Issue 9.5 **What is the Board's role with regard to the approval of the Green Energy Plan? What criteria should the Board use when determining whether to approve the Green Energy Plan? If the Board approves the plan, what are the impacts of that approval?**

Reference: Exhibit A, Tab 14, Schedule 2, page 33 of 34

Hydro One states that it is too early to detail specific measures/criteria against which to measure its Plan. When will Hydro One be in a position to detail specific measures and criteria against which the Board can measure its plan, and when does Hydro One anticipate that the Board will assess its Plan on the basis of such specific measures or criteria?

Response

Please refer to Exhibit H, Tab 9, Schedule 52.