June 8, 2012

Kirsten Walli, Board Secretary
Ontario Energy Board
P.O. Box 2319, 27th Floor
2300 Yonge Street
Toronto, ON M4P 1E4

Attention: Ms. Walli

Re: Espanola Regional Hydro Distribution Corporation's (ERHDC) 2012 Cost of Service Electricity Distribution Rate Application EB-2011-0319 Responses to Board Staff Interrogatories.

ERHDC has attached responses to the Board Staff Interrogatories in the above noted proceedings. The responses have been filed through the Web Portal.

In the event of any additional information, questions or concerns, please contact Jennifer Uchmanowicz, Rate and Regulatory Affairs Officer, at Jennifer.Uchmanowicz@ssmpuc.com or (705) 759-3009.

Sincerely,

Jennifer Uchmanowicz

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Jennifer Uchmanowicz
on behalf of Espanola Regional Hydro Distribution Corporation
Rates and Regulatory Affairs Officer
PUC Services
Sault Ste. Marie Ont.
Email: jennifer.uchmanowicz@ssmpuc.com
Phone: 705-759-3009

Question #1

Ref: Responses to Letter of Comment

Administration

Following publication of the Notice of Application, the Board has to date, received two letters of comment. Please confirm whether ERHDC has received any letters of comment. If so, please file a copy of any letter of comment. For each, please confirm whether a reply was sent from ERHDC to the author of the letter. If confirmed, please file that reply with the Board. Please ensure that the author's contact information except for the name is redacted. If not confirmed, please explain why a response was not sent and confirm if ERHDC intends to respond.

ERHDC Response

ERHDC did not receive any formal letters of comment that would require filing with the Board.

Question #2

Ref: Condition of Service

a) Please identify any rates and charges that are included in ERHDC's conditions of service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.
b) Please provide a schedule outlining the revenues recovered from these rates and charges from 2006 to 2010 and the revenue forecasted for the 2011 bridge and 2012 test years.
c) Please explain whether in ERHDC's view, these rates and charges should be included on ERHDC's tariff sheet.

ERHDC Response

In ERHDC's conditions of service there are no rates and charges that do not appear on the Board-approved tariff sheet.

Question #3

Capital Expenditures

Ref: Exhibit 2/ Tab 2/ Schedule 6/ Page 3 – 2012 Capital Expenditures (Transportation Equipment)

On page 3, it states: "Transportation Equipment (Account 1930) increased in 2012 test year by $190,000. ERHDC requires a new single bucket truck to replace the current aging deteriorating single bucket truck."

a) Please provide more details of the current single bucket truck, such as year, size, condition, mileage, frequency of repairs, annual maintenance and repair costs, etc.

b) Please advise whether ERHDC has performed any condition assessment of the current bucket truck by internal or external party. If so, please file any report from the assessment.

c) Please advise how much of the annual maintenance and repair costs would be saved after replacing it with the new bucket truck.

d) Please confirm whether the savings amount mentioned in (c) has been reflected in the 2012 test year OM&A.

ERHDC Response

a) The details of ERHDC's current single bucket truck is as follows:

Year and Model: 1986 GMC Topkick 7000
Bucket Aerial Device: 1967 Pitman Hotstick single bucket aerial device
Mileage: 191,286 km
Maintenance and Repair costs: 2008 - $6,091
2009 - $6,423
2010 - $2,598
2011 - $4,733

ERHDC's maintenance and repair costs do not include the costs of the recommended repairs as listed in the condition section below. ERHDC has delayed these repairs to minimize costs in expectation of a new bucket truck.

Condition: In 2010 ERHDC's annual aerial device and structural inspection report performed by CUE Engineering Inc. as part of the health and safety act requirements plus inspection by ERHDC's line supervisor identified the following deficiencies:

- Adjustment required to the linkage to the upper controls to enable the unit to properly fold
- Installation of emergency dump at the lower controls
- Replacement of lanyard attachment with D-ring
- Rebuild the upper control assembly (very sloppy)
- Metal fragments identified in engine oil
- Clutch replacement recommended

The overall condition of the bucket truck is not adequate for ERHDC operations. The age of the aerial device (1967) is a safety concern. In addition insurance and liability issues are a concern.

b) The overall condition assessment was performed by line operations supervisor, local repair shops and CUE Engineering inspection reports. ERHDC has attached the report from CUE Engineering. In March 2012, availability of competitive provision of dielectric and structural inspection services was limited due to age of unit.

c) ERHDC forecasts minimal savings of maintenance and repair costs since recommended repairs for the tuck have not been preformed in anticipation of the new truck. Maintenance costs will be ongoing such as annual structural, dielectric and chassis maintenance costs (Oil, lube, filters + CMVI) that are legislative requirements regarding aerial devices and / or commercial vehicles.
Based on the recommended repairs the estimated cost of immediate repairs would be over $10,000 which is expected to not increase the useful life of the truck.

c) Since the repairs performed have been minimal with the expectation of the new truck there are no additional savings included in the 2012 test year OM&A

CUE Engineering Inc.
1401 Dundas St. E., P.O. Box 10, Woodstock, Ontario N4S 7W5 Phone (519)536-9919 Fax (519)536-9928

ANNUAL AERIAL DEVICE STRUCTURAL INSPECTION REPORT

Equipment Owner:	Espanola Hydro	Unit Number:	3
Aerial Device:	Pitman HS36	Chassis:	GMC 7000
Serial Number:	?	VIN:	1GDM7D144GV530599
Date of Mfr.	1967	Date:	1986
Date of Inspection:	June 18, 2010		

The unit was inspected visually and with magnetic particle and ultrasonic inspection as appropriate, in accordance with the Ontario Regulation 213/91. Items found deficient are indicated below.

Repairs Required:

1) Adjust the linkage at the upper controls to enable the unit to properly fold.

Suggestions for Improvement:

1) Suggest installation of emergency dump at the lower controls. There is a spring loaded dump at the lower, but it needs to have a detent to be a valid override of the upper controls/emergency dump.
2) Suggest replacement of lanyard attachment with D-ring.
3) Rebuild the upper control assembly (very sloppy).

Notes:

1) Unit derated. The leakage monitoring system is incomplete.
2) Levelling cables look fine and the manual does not indicate any mandatory replacement time.
3) Verify if the outriggers are required for stability. The original report indicates that torsion bars were present on the unit during the last stability test but they are not there now. Suggest that outriggers be used until the unit can be retested to confirm that they are not required.

Inspected by:

Chad Rayner

Question #4

Ref: Exhibit 2/ Tab 2/ Schedule 2 – Service Quality and Reliability

a) On page 1, it states: "Year over year fluctuations may result from variations in weather such as extreme lightning, excessive snowfalls, ice, storms, foreign interference such as animal contacts and motor vehicles accidents." Please provide the breakdown of the cause of outages for years from 2008 to 2010.

b) Please provide the last three historical years of the service quality indicators and provide an explanation for the indicators that were under performing and the actions taken to address the under performance.

ERHDC Response

a) ERHDC has provided below the breakdown of the causes for outages for the last three historical years.

Outage Code	Description	2009 Totals	2010 Totals	2011 Totals
1	Scheduled	23	10	7
2	Supply	2	1	0
3	Trees	7	7	5
4	Lightning	0	7	0
5	Def. Equip.	8	10	11
6	Weather	0	0	0
7	Human el.	0	0	0
8	Animals, Veh	5	1	3
9	Environment	0	1	0
0	Unknown	3	1	3
	Total	48	38	29

b) ERHDC has provided below the last three historical years (2011, 2010 and 2009) service quality indicators as filed with the OEB.

Telephone Accessibility

The OEB standard for telephone accessibility is at least 65% on a yearly basis. In 2009 and 2010 ERHDC was under performing in telephone accessibility (63.7% and 63.9%)

In 2011 ERHDC improved the telephone accessibility rate to 67.5% meeting the OEB standard.

Appointments Met

In 2011 ERHDC was slightly below the 90% OEB standard of appointments met at 89.2%. ERHDC is monitoring the appointments met for 2012 to ensure the standard is met.

ERHDC has no other under performing areas in the service quality indicators in any of the last three historical years.

2011 Service Quality Indicators

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Report Summary

Filing Due Year	2012
Filing Form Name	2.1.4
RRR Filing No	1,150
Reporting Period and Company Name	January- 2012Espanola Regional Hydro Distribution Corporation, Espanola: Corporation; ED-2002-0502; ;
Licence Type	Distributor
Status	Revised
Report Version	1
Extension Granted	
Extension Deadline	
Filing Due Date	April 30, 2012
Reporting From	Jan 1, 2011
Reporting To	Dec 31, 2011
Submitted On	April 20, 2012
Submitter Name	Noreen Clement
Expiry Date	May 1, 2012

Connection of New Services - Low Voltage (LV)

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code.

OEB Approved Standard: at least 90% on a yearly basis

Month	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
January	0	0	0.00
February	1	1	100.00
March	0	0	0.00
April	0	0	0.00
May	2	2	100.00
June	0	0	0.00
July	1	1	100.00
August	2	2	100.00
September	1	1	100.00
October	0	0	0.00
November	2	2	100.00
December	3	3	100.00

New Connection - LV Annual Totals

Connection of New Services - High Voltage (HV)

The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

New Connection - HV Annual Totals

Annual # of new HV services connected within 10 days	Annual # of new HV services requested	Annual % of new HV services connected within 10 days
0	0	0.00

Appointment Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code

Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
January	41	41	100.00
February	45	46	97.83
March	46	46	100.00
April	29	29	100.00

May	[illegible]	81	98.77
June	90	92	97.83
July	58	60	96.67
August	82	82	100.00
September	70	70	100.00
October	69	69	100.00
November	63	63	100.00
December	47	47	100.00

Appointments Scheduled - Annual Totals

Annual # of appointments scheduled/completed as required	Annual # of appointment requests received	Annual % appointments scheduled/completed as required
720	726	99.20

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.

Please refer to section 7.4 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
January	3	3	100.00
February	3	3	100.00
March	5	5	100.00
April	9	9	100.00
May	8	9	88.89
June	13	20	65.00
July	9	11	81.82
August	13	13	100.00
September	16	16	100.00
October	13	14	92.86
November	7	8	87.50
December	0	0	0.00

99	111	89.20

Telephone Accessibility

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.

Please refer to section 7.6 of the Distribution System Code

OEB Approved Standard: at least 65% on a yearly basis

Month	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
January	267	402	66.42
February	273	413	66.10
March	329	443	74.27
April	299	421	71.02
May	[illegible]5	531	68.74
June	367	503	72.96
July	336	513	65.50
August	346	540	64.07
September	362	559	64.76
October	384	545	70.46
November	394	638	61.76
December	245	370	66.22

Telephone Accessibility Annual Totals

Annual # of qualified incoming calls answered within 30 seconds	Annual # of qualified incoming calls	Annual % qualified incoming calls answered within 30 seconds
3,967	5,878	67.50

Telephone Call Abandon Rate

The percentage of qualified incoming telephone calls that are abandoned before they are answered

Please refer to section 7.7 of the Distribution System Code

OEB Approved Standard: 10% or less on a yearly basis

Month	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
January	30	402	7.46
February	22	413	5.33
March	24	443	5.42
April	31	421	7.36
May	43	531	8.10
June	19	503	3.78
July	34	513	6.63
August	50	540	9.26
September	42	559	7.51
October	33	545	6.06
November	49	638	7.68
December	22	370	5.95
	399	5,678	6.80

Emergency Response Urban

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00

April		2	100.00
May	2	2	100.00
June	0	0	0.00
July	1	1	100.00
August	0	0	0.00
September	1	1	100.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Emergency Response Urban Annual Totals

Annual # of urban emergency calls responded within 60 minutes	Annual # of urban emergency calls	Annual % urban emergency calls responded within 60 minutes
6	6	100.00

Emergency Response Rural

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 120 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

2010 Service Quality Indicators

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Report Summary

Filing Due Year	2011
Filing Form Name	2.1.4
RRR Filing No	290
Reporting Period and Company Name	January- 2011Espanola Regional Hydro Distribution Corporation, Espanola: Corporation; ED-2002-0502; ;
Licence Type	Distributor
Status	Revised
Report Version	1
Extension Granted	
Extension Deadline	
Filing Due Date	March 31, 2011
Reporting From	
Reporting To	
Submitted On	April 4, 2011
Submitter Name	Noreen Clement
Expiry Date	April 5, 2011

Connection of New Services - Low Voltage (LV)

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code.

OEB Approved Standard: at least 90% on a yearly basis

Month	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
January	1	1	100.00
February	0	0	0.00
March	2	2	100.00
April	1	1	100.00
May	2	2	100.00
June	0	0	0.00
July	1	1	100.00
August	2	2	100.00
September	3	3	100.00
October	3	3	100.00
November	1	1	100.00
December	3	3	100.00

New Connection - LV Annual Totals

Annual # of new LV services connected within 5 days	Annual # of new LV services requested	Annual % new LV services connected within 5 days
19	19	100.00

Connection of New Services - High Voltage (HV)

The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Appointment Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code

Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
January	40	40	100.00
February	37	37	100.00
March	37	38	97.37
April	62	63	98.41
May	71	72	98.61
June	140	141	99.29
July	68	68	100.00
August	112	114	98.25
September	89	90	98.89
October	66	67	98.51
November	74	74	100.00
December	41	41	100.00

Appointments Scheduled - Annual Totals

Annual # of appointments scheduled/completed as required	Annual # of appointment requests received	Annual % appointments scheduled/completed as required
837	845	99.10

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.

Please refer to section 7.4 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	16	16	100.00
May	3	4	75.00
June	10	10	100.00
July	3	3	100.00
August	5	6	83.33
September	11	12	91.67
October	10	14	71.43
November	13	14	92.86
December	5	5	100.00

Appointments Met - Annual Totals

Annual # of appointments completed as required	Annual # of appointments scheduled with customer/representative	Annual % appointments met
76	84	90.50

Rescheduling a missed appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed

Please refer to section 7.5 of the Distribution System Code

OEB Approved Standard: 100% on a yearly basis

Month	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00

June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Appointments Rescheduled - Annual Totals

Annual # of appointments rescheduled as required	Annual # of missed/about to be missed appointments	Annual % appointments rescheduled
0	0	0.00

Telephone Accessibility

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.

Please refer to section 7.6 of the Distribution System Code

OEB Approved Standard: at least 65% on a yearly basis

Month	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
January	352	549	64.12
February	280	482	58.09
March	400	555	72.07
April	339	450	75.33
May	259	448	57.81
June	335	610	54.92
July	267	413	64.65
August	294	573	51.31
September	407	641	63.49
October	319	471	67.73
November	286	426	67.14
December	277	351	78.92

Telephone Accessibility Annual Totals

Annual # of qualified incoming calls answered within 30 seconds	Annual # of qualified incoming calls	Annual % qualified incoming calls answered within 30 seconds
3,815	5,969	63.90

Telephone Call Abandon Rate

The percentage of qualified incoming telephone calls that are abandoned before they are answered

Please refer to section 7.7 of the Distribution System Code

OEB Approved Standard: 10% or less on a yearly basis

Month	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
January	39	549	7.10
February	50	482	10.37
March	24	555	4.32
April	18	450	4.00
May	31	448	6.92
June	75	610	12.30
July	25	413	6.05
August	68	573	11.87
September	37	641	5.77
October	45	471	9.55
December	12	351	3.42
November	30	426	7.04

Annual # of qualified incoming calls abandoned after 30 seconds	Annual # of qualified incoming calls	Annual % qualified incoming calls abandoned after 30 seconds
454	5,969	7.60

Written Responses to Enquiries

The percentage of written responses provided within 10 days to qualified enquiries.

Please refer to section 7.8 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
January	1	1	100.00
February	0	0	0.00
March	16	16	100.00
April	0	0	0.00
May	0	0	0.00
June	1	1	100.00
July	0	0	0.00
August	0	0	0.00
September	2	2	100.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Written Responses Annual Totals

Annual # of written responses provided within 10 days	Annual # of qualified enquiries received	Annual % written responses provided within 10 days
20	20	100.00

Emergency Response Urban

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes

January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	1	1	100.00
August	0	0	0.00
September	0	0	0.00
October	1	1	100.00
November	0	0	0.00
December	0	0	0.00

Emergency Response Urban Annual Totals

Annual # of urban emergency calls responded within 60 minutes	Annual # of urban emergency calls	Annual % urban emergency calls responded within 60 minutes
2	2	100.00

Emergency Response Rural

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 120 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Emergency Response Rural Totals

Annual # of rural emergency calls responded within 120 minutes	Annual # of rural emergency calls	Annual % rural emergency calls responded within 120 minutes
0	0	0.00

2009 Service Quality Indicators

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Report Summary

Filing Due Year: 2010	Filing Form Name: 2.1.4	RRR Filing No: 219
Reporting Period and Company Name: January- 2010Espanola Regional Hydro Distribution Corporation, Espanola: Corporation; ED-2002-0502; ;	Licence Type: Distributor	Status: Revised
Report Version: 1	Extension Granted:	Extension Deadline:
Filing Due Date: March 31, 2010	Reporting From:	Reporting To:
Submitted On: March 19, 2010	Submitter Name: Noreen Clement	Expiry Date: May 1, 2010

Connection of New Services - Low Voltage (LV)

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code.

OEB Approved Standard: at least 90% on a yearly basis

Month	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
January	1	1	100.00
February	1	1	100.00
March	0	0	0.00
April	0	0	0.00
May	1	1	100.00
June	2	2	100.00
July	1	1	100.00
August	2	2	100.00
September	3	3	100.00

October	2	2	100.00
November	1	1	100.00
December	0	0	0.00

New Connection - LV Annual Totals

Annual # of new LV services connected within 5 days	Annual # of new LV services requested	Annual % new LV services connected within 5 days
14	14	100.00

Connection of New Services - High Voltage (HV)

The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.

Please refer to section 7.2 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Appointment Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code

Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
January	12	13	92.31
February	21	21	100.00
March	5	8	62.50
April	27	28	96.43
May	41	42	97.62
June	26	31	83.87
July	56	59	94.92
August	43	44	97.73
September	36	40	90.00
October	27	29	93.10
November	40	41	97.56
December	10	11	90.91

Appointments Scheduled - Annual Totals

Annual # of appointments scheduled/completed as required	Annual # of appointment requests received	Annual % appointments scheduled/completed as required
344	367	93.70

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.

Please refer to section 7.4 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Appointments Met - Annual Totals

Annual # of appointments completed as required	Annual # of appointments scheduled with customer/representative	Annual % appointments met
0	0	0.00

Rescheduling a missed appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed

Please refer to section 7.5 of the Distribution System Code

OEB Approved Standard: 100% on a yearly basis

Month	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Appointments Rescheduled - Annual Totals

Annual # of appointments rescheduled as required	Annual # of missed/about to be missed appointments	Annual % appointments rescheduled
0	0	0.00

Telephone Accessibility

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.

Please refer to section 7.6 of the Distribution System Code

OEB Approved Standard: at least 65% on a yearly basis

Month	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
January	323	448	72.10
February	330	534	61.80
March	313	510	61.37
April	279	449	62.14
May	436	705	61.84
June	368	531	69.30
July	409	536	76.31
August	333	439	75.85
September	374	608	61.51
October	315	560	56.25
November	299	525	56.95
December	257	489	52.56

Telephone Accessibility Annual Totals

Annual # of qualified incoming calls answered within 30 seconds	Annual # of qualified incoming calls	Annual % qualified incoming calls answered within 30 seconds
4,036	6,334	63.70

Telephone Call Abandon Rate

The percentage of qualified incoming telephone calls that are abandoned before they are answered

Please refer to section 7.7 of the Distribution System Code

OEB Approved Standard: 10% or less on a yearly basis

Month	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
January	20	448	4.46
February	41	534	7.68
March	31	510	6.08
April	32	449	7.13
May	69	705	9.79
June	36	531	6.78
July	22	536	4.10
August	21	439	4.78
September	45	608	7.40
October	54	560	9.64
November	60	525	11.43
December	53	489	10.84

Annual # of qualified incoming calls abandoned after 30 seconds	Annual # of qualified incoming calls	Annual % qualified incoming calls abandoned after 30 seconds
484	6,334	7.60

Written Responses to Enquiries

The percentage of written responses provided within 10 days to qualified enquiries.

Please refer to section 7.8 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Written Responses Annual Totals

Annual # of written responses provided within 10 days	Annual # of qualified enquiries received	Annual % written responses provided within 10 days
0	0	0.00

Emergency Response Urban

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes

January	0	0	0.00
February	0	0	0.00
March	2	2	100.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Emergency Response Urban Annual Totals

Annual # of urban emergency calls responded within 60 minutes	Annual # of urban emergency calls	Annual % urban emergency calls responded within 60 minutes
2	2	100.00

Emergency Response Rural

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 120 minutes of the call.

The definition of "rural" and "urban" should correspond to the municipality's definition

Please refer to section 7.9 of the Distribution System Code

OEB Approved Standard: at least 80% on a yearly basis

Month	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
January	0	0	0.00
February	0	0	0.00
March	0	0	0.00
April	0	0	0.00

May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	0	0	0.00
December	0	0	0.00

Emergency Response Rural Totals

Annual # of rural emergency calls responded within 120 minutes	Annual # of rural emergency calls	Annual % rural emergency calls responded within 120 minutes
0	0	0.00

Question #5

Load and Customer Forecasting

Ref: Exhibit 3/ Tab 2/ Schedule 1/ Page 3 – Load Forecast - kWhs

In Table 3-3, ERHDC provides a summary of Load and Customer/Connection Forecast. Please provide Table 3-3 again but exclude any CDM adjustments from the Billed (kWh) column for 2011 and 2012 and recalculate the Growth (kWh) and Percent Change for 2011 and 2012.

ERHDC Response

In ERHDC's weather normalization the average heating and cooling degree days for the last historical 8 years were used in calculating the billed kWh for 2011 and 2012. Since the variables are constant the billed kWh before CDM adjustments is also constant. See table below.

Summary of Load and Customer/Connection Forecasts						
Year	Billed (kwh)	Growth	Percentage Change	Customer/ Connection Count	Growth	Percentage Change
2008 Board Approved	63,349,522			4,313		
2003 Actual	64,049,189			4,353		
2004 Actual	63,720,225	(328,964)	-0.5%	4,341	(12)	-0.28%
2005 Actual	63,612,611	(107,614)	-0.2%	4,355	14	0.32%
2006 Actual	61,307,854	(2,304,757)	-3.6%	4,353	(2)	-0.05%
2007 Actual	62,307,251	999,397	1.6%	4,375	22	0.51%
2008 Actual	62,986,996	679,745	1.1%	4,377	2	0.05%
2009 Actual	63,709,854	722,858	1.1%	4,409	32	0.73%
2010 Actual	60,770,606	(2,939,248)	-4.6%	4,392	(17)	-0.39%
2011 Normalized Bridge	62,801,997	2,031,391	3.3%	4,399	7	0.16%
2012 Normalized Test	62,801,997	-	0.0%	4,410	11	0.25%

Question #6

Ref: Exhibit 3/ Tab 2/ Schedule 1/ Page 4 and Exhibit 9/ Tab 2/ Schedule 1/ page 13 – Customer/Connections Number

Table 3-4 provides the actual and forecast number of customer/connections for historical, bridge and test years. Staff has prepared a table below to show the difference as compared to the number of smart meters installed filed under Exhibit 9/ Tab 2/ Schedule 1/ Page 13.

	Exh.3/Tab 2/Sch.1 /p.4 / Table3-4	Exh.9/Tab 2/ Sch.1 /p.13
	2010 Number of Customers	Number of Meters Installed
Residential	2,850	2,879
GS < 50 kW	425	404
GS > 50 kW	25	24

Please explain why the actual 2010 number of customers as stated in Table 3-4 is different from the installed smart meters stated in Exhibit 9/ Tab 2/ Schedule 1/ Page 13.

ERHDC Response

The installed number of meters as listed in Exh.9/Tab2/Sch.1/p.13 is misstated. The metering department included a code in error for multi-residential customer with residential customers instead of GS<50 kW rate class. The number of meters installed by rate class is listed below. There is a small difference due to the number of customers being an average for 2010 and the addition or removal of customers throughout the year.

	Number of Meters Installed
Residential	2,857
GS < 50 kW	426
GS > 50 kW	24

Question #7

Ref: Exhibit 3/ Tab 2/ Schedule 1/ Page 5 – Annual Usage per Customer/Connection

In Table 3-5, ERHDC provides a summary of annual usage per customer/connection by rate class.

a)For the GS<50 kW class, the annual usage in 2010 dropped by 13.7%. Please explain the reason for this decrease.

b) For the GS>50 kW class, the annual usage in 2009 and 2010 dropped by 15.0% and 12.2% respectively. Please explain the reason for the decrease in both years.

c) For the USL class, the annual usage in 2009 dropped by 26.1%. Please explain the reason for this decrease.

ERHDC Response

a) In 2010 the decrease in the annual per customer usage in GS<50 kWh class was a result of a reduction of 14 customers from 2009 to 2010 which skews the usage pattern of a "typical" GS<50 kWh customer for comparative purposes. Also, the overall consumption in 2010 was down approximately 4.5% from 2009.

b) In the GS> 50 kWh rate class the annual per customer usage dropped in 2009 by 15% and in 2010 dropped by 12.2%. In 2009 ERHDC had an increase of 4 customers and in 2010 there was an increase of 5 customers. Depending on the usage of these customers it will skew the comparator results of prior year. Since ERHDC has a small customer base in the GS>50 kWh class (20 to 25 customers) the addition of a few customers or change in a particular customers usage, compared to larger LDC's, will have a greater impact on the annual consumption per customer from year to year. Also, the overall consumption in 2010 was down approximately 4.5% from 2009.

c) In the USL class the annual usage per customer dropped in 2009 by 26.1%. In 2009 ERHDC USL customers count increased by 9 and the overall annual consumption increased accordingly in 2009 by approximately 30%. When comparing the annual usage per customer in 2008 to the annual usage per customer in 2009 the results are skewed as a result of the increased customers and consumption in 2009. The new customers in 2009 may have different demand and usage than the customer in 2008 which skews comparators.

Question #8

Other Revenues

Ref: Exhibit 3/ Tab 3/ Schedule 1 – Summary of Other Distribution Revenues

a) In Table 3-22, ERHDC forecasts that the Specific Service Charges for 2012 is $68,500 which represents a 7% decrease as compared to 2010 actual ($73,559). Please explain the reason(s) for this decrease.

b) In Table 3-22, ERHDC forecasts that the revenues from Merchandise, jobbing, etc for 2012 is $2,500 which represents a 68% decrease as compared to 2010 actual ($7,526). Please explain the reason(s) for this decrease.

ERHDC Response

a) In ERHDC 2012 forecast compared to 2010 actuals there is a decrease of 7% in specific service charges. In ERHDC's 2012 forecast there were less revenues forecast for disconnect and re-connect charges as a result of the revised customer service rules enforced by the OEB (such as arrears management programs and low-income assistance programs, etc) ERHDC confirms the actual 2011 specific customer service charges were $69,000.

b) ERHDC's revenue from merchandising and jobbing fluctuates annually depending on the specific situations that may arise. Due to the uncertainty of the revenue in the 2012 test year and the nature of historical costs usually being one-time expenditures, ERHDC forecast $2,500. For example, in 2007 work was done for a neighbouring utility that was one-time. The historical amounts in account 4325 are as follows:

2004 - $0

2005 - $0

2006 - $10,000

2007 - $30,000

2008 - $14,662

2009 - $6,939

2010 - $7,526

2011 - $2,500

2012 - $2,500

Question #9

Operating, Maintenance and Administrative ("OM&A") Expenses

Ref: Exhibit 4/ Tab 2/ Schedule 5/ Page 4 – 24 – Vegetation Management

On page 5 of the above reference, it states: "ERHDC has increased costs in tree trimming by $32,000 in 2008. In prior years, ERHDC did not have adequate vegetation control in place. In 2008 it became apparent that a significant backlog in vegetation management has developed in the rural areas in ERHDC service territory." In 2009, ERHDC increased its tree trimming costs by an additional $36,000, and there was a further increase in 2010 of $35,000. While there is no further increase in the 2011 Bridge Year, ERHDC is requesting an additional increase of $62,500 related to tree trimming in the 2012 Test Year, which consists of an ongoing cost of $25,000 and one-time cost of $150,000 (amortized over 4 years, or $37,500/year).
In regards to the one-time tree trimming cost, on page 12 of the above reference, it states: "PUC Services review of ERHDC's utility vegetation management identified 13 km of line that requires immediate attention on Bass Lake Road..... The 13 km of line requires extensive trimming, some removals, and management of the brush. The one-time cost to clear the 13 km of line is estimated to be $150,000."

a) ERHDC states that in 2008 a significant backlog in vegetation management had developed in the rural areas of ERHDC's service territory. Please provide the reason for the backlog and advise on the current status of the backlog clearance.
b) Please state how in 2008 ERHDC identified the backlog and provide any assessments of the cost of clearing the backlog that were undertaken at that time.
c) Please provide the number of kilometers of line clearing accomplishments for the years 2008, 2009, 2010 and forecast accomplishments for 2011 and 2012 and also provide the width of the Right-of-Way for the tree trimming for those years.
d) What is the tree trimming cycle that ERHDC has used from 2008 to 2010 and is forecasted for 2011, 2012 and going forward?
e) When does ERHDC plan to start the13km line tree trimming on Bass Lake Road? When does ERHDC expect this work to be finished?
f) Please identify whether there are any unique characteristics of the Bass Lake Road area within ERHDC's service territory that would cause higher vegetation management costs.
g) Please provide the breakdown of the tree trimming costs in the following table including totals for 2013, 2014 and 2015 if available:

Year		2008	2009	2010	2011	2012	2013	2014	2015
13km Bass Lake Road – One time	Costs								
	Costs / km								
13km Bass Lake Road – Ongoing	Costs								
	Costs / km								
All other lines	Costs								
	Costs / km								
Total	Costs	$64,272	$100,443	$135,566	$123,916	$186,001			

h) Please explain the difference in costs, if any, between the 13km Bass Lake Road and all other lines. Please compare the unit cost as shown in the above table and explain the difference.

<u>ERHDC Response</u>

a) The reason for the backlog in vegetation management prior to 2008 is related to a lack of internal capacity to perform the quantity of work required and the lack of financial resources. As vegetation encroachment issues existed throughout the service territory, the system was divided geographically into three sections. The current cycle began with the clearance of lines in the northern half of town and the rural areas immediately North (Old Webbwood Road, Jacklin Rd ,Faraway Road). In 2009, The Bass Lake Road area was not identified as the priority; with the exception of some work to gain minimal clearance in a few areas of that section. Limited resources have prevented the necessary concentration of effort on the Bass Lake road section.

b) In 2008 Espanola Regional Hydro identified, through field observations and employee feedback, the need to initiate a planned approach to managing vegetation around the distribution lines. In addition to the allocation of $64,000 toward line clearing activities, a one ton covered dump truck was purchased to haul chipped wood and more efficiently manage disposal of the debris.

c) Please see attached table per (g). Right of ways, where possible are maintained to provide a clearance from primary voltage lines of 3 meters and from secondary voltage lines of 1 meter. Where easements allow, an 6 to 8 meter ROW was cleared.

d) ERHDC was attempting to develop a tree trimming cycle of three years between 2008 and present. That plan is to be continued going forward. This requires an average annual clearing of approximately 40 km of primary line plus associated secondary lines and services.

e) ERHDC plans to start the work in the fall of 2012. ERHDC plans to have contractor complete the 13km section prior to 2012 year end.

f) Characteristics unique to the Bass Lake Road area include;
   - narrow, bending rural road – additional staff will be required to provide work area protection for a significant portion of the project.
   - primary taps are either off road or along narrow shared private roadways requiring a significant amount of climbing vs. bucket access
   - minimal right of way maintenance (brushing) in prior years thus thick growth beneath or into line(s)
   - planned outages required for several sections, thus prior notification of customers and frequent co-ordination between utility line staff and contractor

g)

Year		2008	2009	2010	2011	2012	2013	2014	2015
13km Bass Lake Road – One time	Costs					$150,000			
	Costs / km					13km $11,538			
13km Bass Lake Road – Ongoing	Costs				$10,000				
	Costs / km				1 km $10,000/km				
All other lines	Costs	$64,272	$100,443	$135,566	$113,916	$36,001			
	Costs / km	28km $2,295/km	36km $2,790/km	34km $3,987/km	11km $10,356/km	4km $9,000/km			
Total	Costs	$64,272	$100,443	$135,566	$123,916	$186,001			

h) The 2008 work did not include any rear lot or climbing work thus the relative low cost. In 2009, in an attempt to speed progress, reduced clearances were provided throughout the section again keeping the costs relatively low, but not providing the desired result. The 2010 section includes Massey which is ½ hour drive from service center which significantly increased the cost per km in that cycle. Contractors targeted mainly the difficult to access back lot or heavy growth areas that required larger equipment and/or climbers while internal staff continued along line sections where there was a more continuous work flow. In 2011, an attempt at the Bass lake road section in combination with scattered removals as opposed to the clearing of continuous line sections resulted in very slow progress and more than doubled the per km cost. The removals were completed to eliminate public safety concerns and /or the need for future clearing of growth. A combination of these factors have driven up the "per km" cost. The Bass lake road section will exceed the 2011 costs.

Question #10

Ref: Exhibit 4 / Tab 2/ Schedule 1 and Exhibit 4/ Tab 2/ Schedule 4 – Service Agreement and Management Agreement

In reference to page 6 of the report prepared by BDR titled "Recommendations on Support for Reasonableness of PUC Services Inc. Contract to Supply Services to Espanola Regional Hydro Distribution Corporation", it states:

The fact that Espanola Hydro is able to procure the services from a third party supplier (PUC Services), and that it once received an offer from an alternative supplier (Greater Sudbury Hydro) to provide the services….."

a) Please advise when the offer from Greater Sudbury Hydro was obtained.

On page 6 of the BDR report, BDR posted a question to Board staff on whether Staff or the Board have any special concerns related to the procurement of services by one LDC from another LDC or its affiliates. Board staff's response is quoted and in part stated that:

…a distributor's costs would be subject to the normal prudency review that occurs during the distributor's rate setting hearing. In these cases the distributor must be able to demonstrate that its costs are reasonable. The ability to demonstrate that the LDC did research the marketplace for the best price either through tendering or obtaining quotes, would certainly be helpful and provide support for the distributor's position."

b) Please describe what marketplace research ERHDC undertook in order to confirm that it received the best price for the contacts currently in effect.

ERHDC Response

a) The offer from Greater Sudbury Hydro was obtained in November 2005 but was subsequently withdrawn in December 2005.

b) In August of 2010 ERHDC engaged BDR to provide support and assess the reasonableness of PUC Services contract with ERHDC. As per the report the assessment indicates the costs per customers are amongst the lowest in the cohort analysis. ERHDC has updated the table based on the 2010 yearbook issued by the OEB (2011 data in not available yet) below:

LDC	Operating	Maintenance	Administrative	Other	Total OM&A	Customers	Expense/ Customer
Algoma Power Inc.	$1,097,534	$3,426,509	$4,123,260	$56,576	$8,703,879	11,612	$750
Atikokan Hydro Inc.	$332,111	$51,665	$615,874	$0	$999,650	1,663	$601
Chapleau Public Utilities Corporation	$203,961	$0	$335,034	$9,588	$548,582	1,306	$420
Espanola Regional Hydro Distribution Corp	$195,034	$282,982	$550,700	$18,327	$1,047,043	3,300	$317
Fort Frances Power Corporation	$192,399	$183,394	$949,892	$12,850	$1,338,534	3,777	$354
Northern Ontario Wires Inc.	$401,967	$343,735	$1,307,987	$2,913	$2,056,602	6,026	$341
Parry Sound Power Corporation	$70,690	$219,988	$922,570	$0	$1,213,249	3,377	$359
Renfrew Hydro Inc.	$198,937	$163,008	$679,154	$0	$1,041,099	4,155	$251
Sioux Lookout Hydro Inc.	$493,191	$116,678	$563,578	$0	$1,173,447	2,754	$426
						Espanola Rank	2
						median	$359
						mean	$424

c)

Question #11

Ref: Exhibit 4/ Tab 2/ Schedule 6/ Page 2 – Employee Compensation and Benefits

a) Table 4-16 provides the employee costs summary by years. The table shows that the total compensation for 2011 and 2012 is $519,560 and $564,718 respectively. This represents an increase in 2012 of $45,158. In reference to Exhibit 4/ Tab 2/ Schedule 5, page 14, ERHDC only provided the reasons to account for a $27,000 increase. Please explain the reasons for the remaining increase (approximately $18,000).

b) Table 4-16 shows the total benefit for 2011 is $158,628 and this represents approximately 38% increase as compared to 2010 actual. Please explain the reason for the increase.

ERHDC Response

a) In 2012, in addition to the $27,000 increase related to management salaries and expenses, there was an increase in labour allocated to OM&A of $13,000 as described in Exhibit 4/ Tab 2/ Schedule 5/ Page 11. The remaining approximately $5,000 difference is a result of labour that was capitalized and not included in OM&A.

b) In 2010 ERHDC had one employee that did not qualify for benefits until 2011. Therefore, the employee's wages were included in 2010 but benefits were not included until 2011.

Question #12

Ref: Exhibit 4/ Tab 2/ Schedule 5/ Page 11 - Low Income Energy Assistance Program (LEAP)

Please state whether or not ERHDC has included an amount in its 2012 Test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

ERHDC Response

ERHDC has not included an amount in the 2012 test year for any legacy energy assistance programs.

Question #13

Ref: Exhibit 4/ Tab 2/ Schedule 6 - Ontario Municipal Employees Retirement System Pension Expense

OMERS has announced a three-year contribution rate increase for its members and employers for the years 2011, 2012, and 2013. Please state whether or not ERHDC's proposed pension costs include this increase. If so, please provide the forecasted increase by years and the documentation to support the increases. If not, please state how ERHDC proposes to deal with this increase

ERHDC Response

OMERS pension costs are included in employee benefit costs. The 2012 test year includes pension costs based on the 2012 increased OMERS rates (8.3%/12.8%) and the employees' projected pensionable earnings.

The rates increased by 12% for the lower tier and 20% for the upper tier. ERDHC's expense increased by $5,666 from $36,632 to $42,298 or 15%. No provision has been made for the 2013 rate increase, which based on a further rate increase of .9%, amounts to approximately $3,800.

Question #14

Green Energy Plan
Ref: Exhibit 2/ Tab 2/ Schedule 7/ Page 8; Exhibit 2/ Tab 2/ Schedule 4/ Page 11; Exhibit 2/ Tab 3/Schedule 1/ Page 50-51

In the first reference ERHDC indicated that capital investments are supported by its asset management plan which includes a major capital investment in distribution substations. ERHDC in the first reference stated in part that:

> *ERHDC's asset management plan on Tab 3, Schedule 1 of this Exhibit supports major capital investments in distribution substations. ERHDC has included a portion of the projected investments for substations 2012 test year in WIP. ERHDC anticipates that the substation will not be complete until 2013.*

In the second reference at Table 2-14, there is an entry for work in progress ("WIP"), under the column "Additions" for $ 2,162,327 In the third reference "the Asset Management Plan" at pages 50-51, it is indicated that Exhibit 5-6 reflects cost of replacement of major equipment at the three distribution stations to reduce the risk of in-service equipment failures and introduce automation for smart grid implementation and to remove obstacles to connection of distributed generation from the renewable resources to grid.

a) Please provide a description and breakdown of the amount of $2,162,237, shown in the second reference by:
 <u>equipment type</u>; and
 <u>by location</u> i.e., in which of the four distribution substations, identified in Exhibit 5-6 of the third reference (reproduced above)

b) Please clarify whether or not the $1,800,000 shown in the third reference against MS 4 is included in the WIP amount of $2,162,327 as shown in the second reference.

ERHDC Response

a) The $2,162,237 in WIP includes $1,800,000 for the substation (MS 4) plus $362,237 for the 44 KV powerline extension associated with the new station (Barrie street).

b) ERHDC confirms the amount in WIP of $2,162,327 includes the $1,800,000 related to MS 4.

Question #15

Ref: Exhibit 2/ Tab 3/ Schedule 1/ Page 7-8; Exhibit 2/ Tab 3/ Schedule 1/ Page 50-51;

Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-20090397], Page 10

On page 7 of the first reference, the last sentence indicated that the overall capital investment required during the next 10 years for asset sustainment is shown on page 8 in tabular form - reproduced below:

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
Stations	900 000	900 000	375 000	375 000	375 000	375 000			375 000	375 000	4 050 000
Overhead Lines	249 150	249 150	249 150	249 150	249 150	249 150	249 150	249 150	249 150	249 150	2 491 500
Underground Lines	16 910	16 910	16 910	16 910	16 910	16 910	16 910	16 910	16 910	16 910	169 100
Distribution transformers	63 640	63 640	63 640	63 640	63 640	63 640	63 640	63 640	63 640	63 640	636 400
Disconnect Switches, Cutouts	3 660	3 660	3 660	3 660	3 660	3 660	3 660	3 660	3 660	3 660	36 600
Total Asset Sustainment CAPEX	1 233 360	1 233 360	708 360	708 360	708 360	708 360	333 360	333 360	708 360	708 360	7 383 600

In the second reference "the Asset Management Plan" at pages 50-51, it is indicated that Exhibit 5-6 (reproduced below) reflects cost of:

-replacement of major equipment at the three distribution stations to reduce the risk of in-service equipment failures; and

-introduce automation for smart grid implementation and remove obstacles to connection of distributed generation from the renewable resources to grid.

	Station Rating	No. of 4 kV feeders	44 kV Switchgear	4 kV switchgear	Estimated Replacement
MS 1	5 MVA	4	Motorized Fused Disconnect	Vacuum Breakers	$ 750 000
MS2	5 MVA	4	Motorized Fused Disconnect	Vacuum Breakers	$ 750 000
MS3	5 MVA	4	Motorized Fused Disconnect	Vacuum Breakers	$ 750 000
MS 4*	5 MVA	4	Motorized Fused Disconnect	Vacuum Breakers	$ 1 800 000
Total Estimated Replacement Cost of All Stations					$ 4 050 000
* Includes site development and building costs					

Exhibit 5-6: Capital Investment Needs – Distribution Stations (Sustainment)

There is also an indication that 2012 investments are included in a WIP account. Please complete a new table, as shown below:

Covering 2012 (Test Year), and the following four years (2013, 2014, 2015, and 2016);

For each year provide a break down of the total amounts of investment into each of the four stations.

Investment in the Distribution Stations In Dollars [5-year Horizon - Green Energy Plan]						
	2012	**2013**	**2014**	**2015**	**2016**	**Total Investments**
MS1						
MS2						
MS3						
MS 4						
Total Investment						

ERHDC Response

Investment in the Distribution Stations In Dollars [5-year Horizon - Green Energy Plan]						
	2012	**2013**	**2014**	**2015**	**2016**	**Total Investments**
MS1					375,000	375,000
MS2						
MS3						
MS 4	2,162,327	549,000				2,711,327
Total Investment						

Question #16

Ref: Exhibit 2/ Tab 3/ Schedule 2/ Page 3-6;
Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-20090397], Page 18; Distribution System Code ("DSC"), last amended October 1, 2011

In the first reference, the Green Energy Plan indicated that a 10 year plan for the three existing distribution stations that need major investments has three objectives:

Provide adequate station capacity at 4 kV bus to meet the existing system loading needs and for future load growth;

Replace distribution station assets reaching end of their useful service life; and

Remove system constraints that hinder connection of renewable generation and are an impediment to smart grid development.

In the second reference, the Filing Requirements on page 18 limits activities classed as "Smart Grid" and states in part that:

> *At the present time, smart grid development activities and expenditures should be limited to smart grid demonstration projects, smart grid studies or planning exercises and smart grid education and training.*

In the third reference, the DSC in section 3.3.2 classes certain initiatives by a distributor as "Renewable Enabling Improvements", and states that:

> *3.3.2 Renewable enabling improvements to the main distribution system to accommodate the connection of renewable energy generation facilities are limited to the following:*
>
> *(a) modifications to, or the addition of, electrical protection equipment;*
> *(b) modifications to, or the addition of, voltage regulating transformer controls or station controls;*
> *(c) the provision of protection against islanding (transfer trip or equivalent);*
> *(d) bidirectional reclosers;*
> *(e) tap-changer controls or relays;*

(f) replacing breaker protection relays;
(g) Supervisory Control and Data Acquisition system design, construction and connection;
(h) any other modifications or additions to allow for and accommodate 2-way electrical flows or reverse flows; and
(i) communication systems to facilitate the connection of renewable energy generation facilities.

a) Please complete another version of the table requested in Interrogatory 16, above, with investments to represent replacements classed as "like-for-like". The "like-for-like" investments represent what would be incurred to replace station assets reaching end of useful life i.e., the equipment are not designed to accommodate renewable generation to be connected to ERHDC's system.

b) Please comment on the view that given the Board Filing Requirement as prescribed in the second reference, investments in the three distribution stations will not likely be accepted as "Smart Grid" investments.

c) Please comment on the view that the difference between the investments in the table of Interrogatory 16, and the corresponding investments in part (a) of this interrogatory, subject to review by the Board, can be viewed as investments that can be classed as "*Renewable enabling improvements*" as described in the third reference.

d) Please provide a breakdown of investments calculated in (c) above for each station by year (if possible). The breakdown should be provided for the various components including:

Investments in breakers over the investments for the currently used fused cut-outs;

Investment in SCADA-related equipment to effect automation capabilities; and

Modernizing the protection and control schemes.

ERHDC Response

a) ERDHC's MS4 is a new substation therefore a like-for-like comparison is not available. The projected investment in MS1 in 2016 is at the preliminary planning stages and detail costing for a like-for-like comparison is not yet available.

b) Investment in the three distribution stations is at the preliminary planning stages and the eligibility of smart grid investments at this stage have not been considered.

c) The investment for substation #4 is for a new substation to increase capacity. The projected investment in MS1 is at the preliminary planning stages.

d) ERHDC 's investments are at the planning stage and a breakdown for each station by year and components is not available.

Question #17

Ref: Exhibit 2/ Tab 3/ Schedule 1/ Page 26-33; Exhibit 2/ Tab 3/ Schedule 1/ Appendix A – Substation Condition Assessment Report; Exhibit 2/ Tab 3/ Schedule 1/ Page 45

In the first reference, a systematic approach to evaluate the distribution station's major assets is set out. In that first reference ranking for each of the major assets covers "Condition Assessment", followed by "Scoring".

In the second reference, the noted Condition Assessment Report made a detailed assessment of the three distribution stations (MS1, MS2, and MS3), and made specific recommendations for various tests to be completed, and a cycle for repeating those tests…etc.

The third reference in Exhibit 4-12, reproduced below, reported in a tabular form the overall health score of the three distribution stations.

Exhibit 4-12 shows the overall health score for the three existing distribution stations and provides an estimate of their useful remaining life.

		Condition Assessment (Score out of 10)									
Sub #	Age Related Score	Xformer	44 kV Switchgear	4 kV Switchgear	Cables	Ground Grid	Fences	Buildings	Total Score (Out of 100)	Remaining Useful Service Life	Priority for station rebuild
Assigned Weight	30%	20%	10%	20%	5%	5%	5%	5%	100%		
MS 1	1	5	7	7	7	6	8	8	48.5	Less than 5 Years	1
MS2	2	4	7	7	7	6	6	8	48.5	Less than 7 Years	2
MS3	1	5.5	7.5	7.5	7	6	10	10	53	Less than 10 Years	3

Exhibit 4-12: Station Equipment Condition Assessment

a) Please provide the details using the constructs provided in section 3.3 of the first reference, to arrive at the results reported in Exhibit 4-12 in the third reference. Please show for each distribution station:

all assumptions and how the scoring has been determined for each major station component; and

rationale for the various weights between the major station components.

b)Please provide an update and indicate which of the following tests outlined below have been completed, and provide a summary of the results of such tests including any recommendations:

MS-3: at Exhibit 2/Tab 3/Schedule 1, on pages 58 – 59 – "d. Recommendations for additional testing"

MS-1: at Exhibit 2/Tab 3/Schedule 1, on page 60 – "c. Summary"

MS-2: at Exhibit 2/Tab 3/Schedule 1, on page 61 – "d. Summary"

ERHDC Response

a) Based on the methodology provided in "Reference 1", health and condition assessment indicators were assessed for each of the major asset employed at the substation, using all available condition assessment data, including age, loading level, visual inspections and test results, as applicable. Table 1 below shows the health indicators employed for various assets and results of scoring complete with the weights and assumptions assigned to various health indicators.

The weights provided to each asset and major component are based on (a) criticality of each individual asset to reliability of power supply (b) safe, efficient and reliable operation of the substation. The assigned weights are in line with the best utility practices.

b) As indicated in Table 2 below, the deficiencies identified during the condition assessment of substations in 2008 were rectified and recommended maintenance and testing were performed during 2009, 2010 and 2011.

Table 1: Substations Health Index Development

Power Transformers							
		Age	Peak load	Inspections	Testing	Component Health Score	Compressed Score Used In Exhibit 4-12
	Weight	6	4	2	8		
MS-1	Score	1	2	2	4	50	5
MS-2	Score	2	2	2	2	40	4
MS-3	Score	1	2	4	4	54	5.5

Switchgear (44 kV)							
		Age	N/A	Inspections	Testing		
	Weight	8		4	8		
MS-1	Score	3		3	4	68	7
MS-2	Score	3		3	4	68	7
MS-3	Score	4		3	4	76	7.5

Switchgear (4 kV)							
		Age	N/A	Inspections	Testing		
	Weight	8		4	8		
MS-1	Score	3		3	4	68	7
MS-2	Score	3		3	4	68	7
MS-3	Score	4		3	4	76	7.5

Cables							
		Age	N/A	Inspections	Testing		
	Weight	8		4	8		

MS-1	Score	3		3	4	68	7
MS-2	Score	3		4	4	72	7
MS-3	Score	3		4	4	72	7

Ground Grid							
		Age	N/A	N/A	Testing		
	Weight	10			10		
MS-1	Score	2			4	60	6
MS-2	Score	3			3	60	6
MS-3	Score	3			3	60	6

Fences							
		Age	N/A	N/A	N/A		
	Weight	20					
MS-1	Score	4				80	8
MS-2	Score	3				60	6
MS-3	Score	5				100	10

Buildings							
		Age	N/A	N/A	N/A		
	Weight	20					
MS-1	Score	4				80	8
MS-2	Score	4				80	8
MS-3	Score	5				100	10

ERHDC has included below Table 2: Mitigation of Deficiencies Identified in 2008

MS - 3 pg. 58 -59 - "d. Recommendations"					
Recommendation	**Completed / Corrected**	**Service Provider**	**Results**	**Follow-up required**	**Completed / Scheduled**
i - transformer oil analysis 1, 2 &3	2008, 2009, 2010, 2011	G.E. Canada/ Weidman	Within tolerance	annual analysis 2012 +	scheduled for 2012 +
ii - infrared testing	2009, 2010, 2011	Schneider Electric / PUC Services	Within tolerance	annual IR scanning	scheduled for 2012 +
iii - 1. Load Break switch	2009	G.E. Canada / ERHDC	Within tolerance	3 year mtce schedule	scheduled for 2012, 2015, etc
iii - 2. Transformer	2009	G.E Canada / Costello	Air Breather outstan	Install Air breather	scheduled for 2012
iii - 3. Switchgear	2009	G.E Canada	Complete	3 year mtce schedule	scheduled for 2012, 2015, etc
iv - cables	2009	G.E Canada	Within tolerance	3 year mtce schedule	scheduled for 2012, 2015, etc
v - Ground Resistance Test	2009	Costello			Completed 2009

MS-1 pg. 59 - "b. Deficiencies"					
Deficiencies	2009	Costello / ERHDC	vii, viii outstanding	Breathers (vii.), Replace	Completed 2011
MS-1 pg. 60 - "c. Summary"					
Routine Mtce	2011	G.E Canada / ERHDC	Within tolerance	3 year mtce schedule	scheduled for 2014
Mtce Outage schedule	2011	G.E. Canada / ERHDC	Within tolerance	3 year mtce schedule	schedule 2014, 2017, etc.
Transformer oil analysis 1,2 &3	2008, 2009, 2010, 2011	G.E. Canada/ Weidman	High moisture 2009	Quarterly Furan analysis 2010, no accelerated degradation, continue annual analysis of 1, 2 3,&4	scheduled for 2012 +

MS-2 pg. 60 -"b. High priority issues"					
High priority issues	2009	Costello, ERHDC	Potheads outstandir	Replace Potheads	completed 2010
MS-2 pg. 61 -"c. Other issues"					
Other Issues	2009	Costello, ERHDC	Porcelain arrestors (viii.) outstanding, 5 kv metalclad switchgear rust (ix) outstanding, Oil Temp Gauge outstanding (x)	ReplacePorcelain arrestors (viii.), Clean & Paint 5 kv metalclad switchgear (ix) , Replace Oil Temp Gauge	Completed Clean and paint metalclad 2010, Completed Temp guage and Arrestor replacements 2011
MS-2 pg. 61 -"d. Summary"					
Routine Mtce	2010	G.E Canada / ERHDC	Defective 44kv and 4160 v Transformer Bushings identified	Replace Defective 44kv and 4160 v Transformer Bushings	Completed Transformer Bushing replacements 2011, Routine mtce. scheduled for 2013
Mtce Outage schedule	2010	G.E. Canada / ERHDC			schedule 2013, 2016, etc.
Transformer oil analysis 1,2 &3	2008, 2009, 2010, 2011	G.E. Canada / Weidman			

Question #18

Ref: Exhibit 2/ Tab 3/ Schedule 2/ Page 1; Exhibit 1/ Tab 1/ Schedule 5/ Page 1-2; *Filing Requirements: Distribution System Plans – Filing under Deemed Condition of Licence, issued March 25, 2010 [EB-20090397], Page 22-23;* Exhibit 2/ Tab 3/ Schedule 1/ Page 1; *Report of the Board – Framework for Determining the Direct Benefit Accruing to Consumers of a Distributor under Ontario Regulation 330/09, issued June 10, 2010*

In the first reference, ERHDC did not explicitly indicate whether or not it is seeking approval of its Green Energy Plan.

In the second reference, ERHDC did not include the Green Energy Plan in the list of "Specific Approvals Requested" by ERHDC.

In the third reference at pages 22 and 23, three Accounts are described in relation to Renewable Generation Connection Deferral Accounts.

In the fourth reference ERHDC indicated that its Asset Management Plan supports major capital investments in distribution stations in 2012 to 2017, and that in this application ERHDC has not included increased capital expenditures in the 2012 test year for distribution stations due to time constraints. ERHDC also indicated that capital investments will not be started until 2013, and intends to apply for recovery in an IRM year utilizing the incremental capital module (ICM) to address the treatment of new capital needs that arise during the IRM plan term that are non-discretionary.

a) Please indicate whether or not ERHDC is applying for approval of its Green Energy Plan.
b) Please confirm whether or not ERHDC intends to apply for cost recovery in the event that it incurs Green Energy related qualifying costs, as set out in pages 20-22, "Section VI. GEA Plan Approval", of the third reference, in its next cost of service application.
c) If the answer to (b) is affirmative, please confirm that ERHDC would be recording the costs as described on pages 22 and 23 of the third reference. Please also discuss whether any of the costs may be recovered from provincial rate payers as prescribed in the fifth reference
d) Please discuss how ERHDC intends to address the Filing Requirements addressed in the third reference and the two preceding questions (b) and (c) above and ERHDC's ICM capital module as noted in the fourth

reference.

ERHDC Response

a) Yes, ERHDC is applying for approval of its Green Energy Plan.

b) There are no system upgrades or expansions proposed under the current rate application. Therefore ERHDC does not expect to incur any Green Energy related qualifying costs within the time frame of the current rate application.

c) n/a

d) n/a

Question #19

Ref: Exhibit 2/ Tab 3/ Schedule 2/ Page 3; Exhibit 2/ Tab 3/ Schedule 2/ Page 8 – OPA Letter of Comment

In the first reference, ERHDC indicated that there are currently:

6 pending MicroFIT connections; and

3 MicroFIT applications at various stages registered on the OPA website.

In the second reference, the OPA letter reported 14 MicroFIT projects totaling 85 kW of which:

1 MicroFIT is connected;

4 MicroFIT under review; and

9 MicroFIT Pending In addition in the second reference, the OPA reported One 250 kW FIT project.

a) Please provide an update to the number of MicroFIT and FIT projects that are:
   Connected;
   Under Review; and
   Pending.

b) Please provide the information as to which feeder the 250 kW project would be connected to, and which of the substations that feeder is supplied from i.e., is it MS1, MS2 or MS3.

c) Please also provide similar information as supplied in (b) above for all new FIT projects that ERHDC identifies in response to question (a) above.

ERHDC Response

a) The updated number of Micro FIT and FIT projects is as follows:

- 19 Application since implementation
- 1 Micro-Fit connected

- 6 Terminated
- 4 pending connections (some since 2010)
- 3 Submitted to the OPA
- 5 pending LDC Offer to connect

b) The connection proposed for the 250 kW project under review by the OPA, should the project proceed, is Feeder 2F7 via Espanola's MS#2.

c) Four potential generators have engaged ERHDC for initial consultation under the FIT program. No connection impact assessments or offers to connect have been requested or completed for FIT projects in ERHDC's service territory.

Question # 20
Cost of Capital and Rate of Return

Ref: Exhibit 5/ Tab 1/ Schedule 1 and Exhibit 5/ Tab 1/ Schedule 4 – Long-term Debt

With respect to long-term debt, ERHDC states:

> ERHDC is requesting a return on Long Term Debt for the 2012 Test Year of 5.01% in accordance with the Cost of Capital Parameter Updates for 2012 Cost of Service Applications for rates effective January 1, 2012 issued by the OEB on November 10th 2011.
>
> ERHDC has a note payable to the Town of Espanola in the amount of $1,185,416 and a note payable to the Township of Sables-Spanish in the amount of $339,095. The notes are without security and are due on demand with one year's written notice and include interest at 5.82% per annum.

ERHDC has provided a copy of the Loan Agreement between ERHDC and the Town of Espanola on pages 4-6 of Exhibit 5/ Tab 1/ Schedule 4. Clause 3 of that loan agreement states: On March 2, 2012 the Board issued updated Cost of Capital parameters for cost of service applications with rates effective May 1, 2012. The following table summarizes the cost of capital parameters based on January 2012 data for rates effective May 1, 2012:

3.0 INTEREST RATE

3.1 The Promissory Note is further amended by deleting the words "without interest" from the first paragraph and substituting the following:

> **This Note shall bear interest at the rate of 5.82 percent per annum calculated from January 1st, 2009. Interest shall be payable on the last day December in each year. Notwithstanding the foregoing the interest rate will be adjusted periodically to the deemed interest rate for Ontario local distribution utilities as determined by the Ontario Energy Board and included in the Borrower's distribution rates to customers.**

Return on Equity: 9.12%
Long-term Debt Rate: 4.41%
Short-term Debt Rate: 2.08%

a) ERHDC has not provided a copy of the loan agreement with the Township of

Sables-Spanish River, a minority shareholder in ERHDC. However, the terms of that agreement are pertinent to assessing the applicable long-term debt rate in accordance with the guidelines in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, issued December 11, 2009. Please confirm that the Loan Agreement between ERHDC and the Township of Sables-Spanish River contains a clause equivalent to Clause 3 shown above. In the alternative, please provide a copy of the Loan Agreement between ERHDC and the Township of Sables-Spanish River and explain the applicable debt rate.

b) In light of Clause 3 and the updated Cost of Capital parameters documented in the Board's letter of March 2, 2012, please confirm that the deemed long-term debt rate of 4.41% should apply to both notes. In the alternative please explain and support your response.

ERHDC Response

ERHDC has provided a copy of the loan agreement with the Township of Sables-Spanish River below. ERHDC confirms that the deemed long-term debt rate of 4.41% should apply to both notes.

THIS AGREEMENT made the 3rd day of March, 2009.

B E T W E E N:

The Corporation of the Township of Sables-Spanish Rivers,
a Municipal Corporation,

(hereinafter referred to as the "Holder")

- and –

Espanola Regional Hydro Distribution Corporation, an Ontario Corporation,

(hereinafter referred to as the "Borrower")

THIS AGREEMENT WITNESSES that in consideration of the mutual covenants and conditions contained herein and other good and valuable consideration the parties hereto agree as follows:

1.0 BACKGROUND

1.1 The Borrower is indebted to the Holder in the amount of Eight Hundred and Forty Nine Thousand Dollars ($849,095.00) as evidenced by a promissory note dated November 1st, 2000 (the "Promissory Note");

1.2 As a result of legislative changes imposing debt/equity limits on Municipal Electric Utilities in Ontario the parties hereto have agreed to amend the Promissory Note as provided herein.

2.0 CONVERSION OPTION

2.1 The Promissory Note is hereby amended by adding the following paragraph:

The Holder shall, at any time during the currency of this Note, have the option to convert all or any part of the principal of the Note into Special Shares of the Borrower at the rate of $10,000.00 per share. This option shall be exercised by the Holder by written notice delivered or sent by registered mail to the Borrower at the Borrower's principal place of business specifying the amount of principal to be converted and the effective date of the conversion, which date shall not be less than ten (10) days from the date of the Notice. The Borrower shall, on the effective date specified in the Notice, issue to the Holder as fully paid and non-assessable such number of Special Shares as may be required to convert the amount of principal specified in the notice at the rate aforesaid and upon the issuance of such Shares the principal amount of the Note shall be reduced accordingly.

3.0 INTEREST RATE

3.1 The Promissory Note is further amended by deleting the words "without interest" from the first paragraph and substituting the following:

This Note shall bear interest at the rate of 5.82 percent per annum calculated from January 1st, 2009. Interest shall be payable on the last day December in each year. Notwithstanding the foregoing the interest rate will be adjusted periodically to the deemed interest rate for Ontario local distribution utilities as determined by the Ontario Energy Board and included in the Borrower's distribution rates to customers.

4.0 REQUEST FOR PAYMENT

4.1 The Promissory Note is further amended by deleting the words "on demand" from the first sentence and substituting the following:

"on demand, with one year's written notice, "

5.0 INTERPRETATION

5.1 A copy of this Agreement signed by both parties shall be attached to the Promissory Note and shall form a part thereof.

5.2 Except as amended herein the Promissory Note shall remain in full force and effect and the Borrower hereby reaffirms its obligations to the Holder pursuant to the Note notwithstanding the amendments contained herein.

5.3 This Agreement shall be governed by and interpreted in accordance with the laws of the Province of Ontario.

5.4 This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF Espanola Regional Hydro Distribution Corporation has executed this Agreement on the 3rd day of March, 2009.

Espanola Regional Hydro Distribution Corporation

Per: ______________________
Brian Curran, President

Per: ______________________
Terry Greco, Treasurer

We have authority to bind the Corporation

IN WITNESS WHEREOF The Corporation of the Township of Sables-Spanish Rivers has executed this Agreement on the 11th day of March, 2009.

THE CORPORATION OF THE TOWNSHIP OF SABLES-SPANISH RIVERS

Per: ______________________
Les Gamble, Mayor

Per: ______________________
Ellen Jordan, Clerk

We have authority to bind the Corporation

Question # 21

Cost Allocation

Ref: Exhibit 7/ Tab 1/ Schedule 2/ Page 1 – Cost Allocation Model

The worksheet I7.1 of the cost allocation model provided the capital costs for Smart Meters for Residential GS < 50 kW and GS > 50 kW classes. Staff has prepared a table below to show the difference as compared to the smart meter costs filed under Exhibit 9/ Tab 2/ Schedule 1/ page 13.

	Sheet I 7.1 Meter Capital		Exh.9/Tab 2/ Sch.1 /p.13	
	Number of Meters	Cost per Meter (Installed)	Number of Meters	Cost per Meter
Residential	2,847	$195	2,879	$190.06
GS < 50 kW	425	$195	404	$265.45
GS > 50 kW	27	$195	24	$894.92

a) Please explain the difference in the cost per meter used in the cost allocation model and in Exhibit 9/ Tab 2/ Schedule 1/ Page 13.

b) Please explain why the number of residential smart meters as shown on Sheet I7.1 is less than the installed smart meters stated in Exhibit 9/ Tab 2/ Schedule 1/ page 13.

c) If necessary, please rerun the cost allocation model. If the new cost allocation model is intended to replace the existing one, please submit a copy of the input sheet and worksheet O1 with the interrogatory response and file an updated version of the live Excel model.

ERHDC Response

a) In the cost allocation model ERHDC used a constant value for the smart meters to allocate costs to the rate classes. In the smart meter disposition model

ERHDC calculated a class specific cost with more appropriately allocates costs. The costs allocation model will be re-run and submitted with these interrogatories to reflect the class specific smart meter costs.

b) The installed number of meters is misstated. The metering department included a code in error for multi-residential customer with residential customers instead of GS<50 kW rate class. The correct number of meters installed by rate class is listed below.

	Number of Meters Installed
Residential	2,857
GS < 50 kW	426
GS > 50 kW	24

c) ERHDC has re-run the costs allocation model with the updated smart meter cost allocations and number of meters.

Question #22

Ref: Exhibit 7/ Appendix A – Cost Allocation Model

In reference to worksheet I8 of the cost allocation model, the LTNCP12 for GS > 50 kW class is 33,672 kW.

a) Please explain why the LTNCP12 is not less than the PNCP12 for the same class, given that sheet I6.1 is showing 19,187 kW of customers' receiving line transformer allowance. Please confirm whether the demand value in LTNCP1, LTNCP4 and LTNCP12 for GS > 50kW should be equal to the demand value of its SNCP1, SNCP4, and SNCP12 respectively.
b) If necessary, please rerun the cost allocation model. If the new cost allocation model is intended to replace and existing one, please submit a copy of the input sheet and worksheet O1 with the interrogatory response and file an updated version of the live Excel model.

ERHDC Response

a) ERHDC confirms that LTNCP12 should be less than PNCP12 for the GS>50 class. In addition, ERHDC confirms that the demand value in LTNCP1, LTNCP4 and LTNCP12 for GS > 50kW should be equal to the demand value of its SNCP1, SNCP4, and SNCP12 respectively.
b) ERHDC will rerun the cost allocation model and file an updated Excel model. Below ERHDC has included an updated sheet I8 for Demand Data and an updated worksheet O1.

2012 COST ALLOCATION
Espanola Regional Hydro Distribution Corp
EB-2011-0319
Saturday, January 00, 1900
Sheet I8 Demand Data Worksheet - Run 1

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	8	9
Customer Classes		Total	Residential	General Service < 50 kW	General Service 40 to 4,999 kW	Street Lights	Sentinal Lights	Unmetered Scattered Load
CO-INCIDENT PEAK								
1 CP								
Transformation CP	TCP1	14,043	7,874	3,212	2,919	13		25
Bulk Delivery CP	BCP1	14,043	7,874	3,212	2,919	13		25
Total Sytem CP	DCP1	14,043	7,874	3,212	2,919	13		25
4 CP								
Transformation CP	TCP4	53,156	29,851	11,898	11,116	181	5	105
Bulk Delivery CP	BCP4	53,156	29,851	11,898	11,116	181	5	105
Total Sytem CP	DCP4	53,156	29,851	11,898	11,116	181	5	105
12 CP								
Transformation CP	TCP12	126,197	66,365	27,891	31,068	543	18	312
Bulk Delivery CP	BCP12	126,197	66,365	27,891	31,068	543	18	312
Total Sytem CP	DCP12	126,197	66,365	27,891	31,068	543	18	312
NON CO_INCIDENT PEAK								
1 NCP								
Classification NCP from Load Data Provider	DNCP1	15,163	8,719	3,218	3,033	157	8	28
Primary NCP	PNCP1	15,163	8,719	3,218	3,033	157	8	28
Line Transformer NCP	LTNCP1	14,040	8,719	3,218	1,910	157	8	28
Secondary NCP	SNCP1	14,002	8,719	3,180	1,910	157	8	28
4 NCP								
Classification NCP from Load Data Provider	DNCP4	56,971	32,310	12,010	11,885	626	31	108
Primary NCP	PNCP4	56,971	32,310	12,010	11,885	626	31	108
Line Transformer NCP	LTNCP4	52,569	32,310	12,010	7,483	626	31	108
Secondary NCP	SNCP4	52,427	32,310	11,869	7,483	626	31	108
12 NCP								
Classification NCP from Load Data Provider	DNCP12	135,509	70,229	29,345	33,672	1,875	75	312
Primary NCP	PNCP12	135,509	70,229	29,345	33,672	1,875	75	312
Line Transformer NCP	LTNCP12	123,037	70,229	29,345	21,201	1,875	75	312
Secondary NCP	SNCP12	122,692	70,229	29,000	21,201	1,875	75	312

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	General Service < 50 kW	General Service 40 to 4,999 kW	Street Lights	Sentinal Lights	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$1,225,251	$732,471	$257,154	$179,801	$48,942	$1,087	$5,797
mi	Miscellaneous Revenue (mi)	$139,899	$94,676	$22,553	$11,696	$10,187	$246	$542
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$1,365,150	$827,147	$279,707	$191,497	$59,129	$1,332	$6,339
	Factor required to recover deficiency (1 + D)	1.3456						
	Distribution Revenue at Status Quo Rates	$1,648,671	$985,597	$346,020	$241,936	$65,855	$1,462	$7,800
	Miscellaneous Revenue (mi)	$139,899	$94,676	$22,553	$11,696	$10,187	$246	$542
	Total Revenue at Status Quo Rates	$1,788,570	$1,080,273	$368,574	$253,632	$76,042	$1,708	$8,342
	Expenses							
di	Distribution Costs (di)	$619,833	$360,553	$111,479	$88,916	$55,515	$1,120	$2,250
cu	Customer Related Costs (cu)	$398,394	$302,977	$74,084	$13,848	$4,900	$292	$2,294
ad	General and Administration (ad)	$354,398	$230,799	$64,548	$35,859	$21,126	$492	$1,574
dep	Depreciation and Amortization (dep)	$143,296	$92,420	$24,796	$16,029	$9,460	$209	$382
INPUT	PILs (INPUT)	$9,329	$5,857	$1,639	$1,109	$683	$13	$27
INT	Interest	$108,404	$68,056	$19,045	$12,887	$7,942	$155	$319
	Total Expenses	$1,633,654	$1,060,660	$295,592	$168,649	$99,626	$2,282	$6,846
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$154,916	$97,256	$27,216	$18,417	$11,349	$222	$456
	Revenue Requirement (includes NI)	$1,788,570	$1,157,916	$322,808	$187,066	$110,975	$2,503	$7,302
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$7,116,038	$4,358,367	$1,252,541	$908,115	$561,997	$12,346	$22,671
gp	General Plant - Gross	$1,093,513	$684,169	$191,981	$128,349	$84,107	$1,584	$3,323
accum dep	Accumulated Depreciation	($4,841,070)	($2,937,140)	($853,262)	($642,605)	($383,367)	($9,033)	($15,664)
co	Capital Contribution	($261,756)	($155,464)	($45,479)	($24,842)	($34,357)	($450)	($1,163)
	Total Net Plant	$3,106,725	$1,949,933	$545,780	$369,018	$228,380	$4,447	$9,167
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$6,141,868	$3,224,429	$1,111,545	$1,720,983	$61,484	$2,384	$21,043
	OM&A Expenses	$1,372,625	$894,328	$250,111	$138,623	$81,541	$1,905	$6,118
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	$7,514,493	$4,118,757	$1,361,656	$1,859,606	$143,025	$4,288	$27,161
	Working Capital	$1,127,174	$617,813	$204,248	$278,941	$21,454	$643	$4,074
	Total Rate Base	$4,233,899	$2,567,747	$750,029	$647,959	$249,833	$5,090	$13,241
		Rate Base Input equals Output						
	Equity Component of Rate Base	$1,693,560	$1,027,099	$300,011	$259,184	$99,933	$2,036	$5,297
	Net Income on Allocated Assets	$154,916	$19,613	$72,982	$84,984	($23,584)	($574)	$1,496
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0
	Net Income	$154,916	$19,613	$72,982	$84,984	($23,584)	($574)	$1,496
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	93.29%	114.18%	135.58%	68.52%	68.21%	114.24%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($423,420)	($330,769)	($43,101)	$4,432	($51,847)	($1,171)	($964)
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($77,643)	$45,765	$66,567	($34,933)	($796)	$1,040
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.15%	1.91%	24.33%	32.79%	-23.60%	-28.20%	28.24%

Question # 23

Rate Design

Ref: Exhibit 8/ Tab 1/ Schedule 4 – Low Voltage

a) ERHDC proposed its total Low Voltage cost for 2012 as $144,544. Please provide a detailed calculation of ERHDC's Low Voltage cost, showing its forecast of load to be billed at the rate for Common ST Lines, the number of meters subject to Hydro One's meter charge, and any other charges that are applicable to ERHDC from its host distributor (other than Retail Transmission Service charges).

b) Please provide the actual Low Voltage costs for 2008, 2009 and 2010.

ERHDC Response

a) ERHDC has 5 accounts that calculate LV charges, Espanola TS-M2, Webwood ME, Espanola Regional H, Espanola PME1 and Massey ME. These accounts are charged based on a combination of monthly service charges, Specific ST Lines charge per KM, LVDS charge per KW, common ST lines per KW and HVDS-Low per KW. ERHDC forecast the load to be billed by taking the average billed amounts from 2008 to 2011. ERHDC then applied the current 2012 Hydro One rates to the averages. ERHDC revised 2012 forecast of Low Voltage costs are $229,288. ERHDC has included the calculation of the LV charges and revised rate riders below.

Espanola Low Voltage Charges

		Jan.	Feb.	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Estimated Rate	Annual Cost
Espanola Regional H																
4265216004																
Common ST Lines - kW	average	11,372	10,551	9,606	8,085	7,035	7,335	7,583	7,673	7,530	7,580	8,846	10,903	104,098	$0.668	$69,537.30
Espanola PME1																
797811002																
	average															
Meter		1	1	1	1	1	1	1	1	1	1	1	1	12	$466.14	$5,593.68
Monthly Service Ch														12	$292.56	$3,510.72
LVDS - kW		320	300	256	221	179	154	160	165	167	205	237	307	2,669	$1.944	$5,188.05
Webbwood ME																
2543997004																
	average															
Meter		1	1	1	1	1	1	1	1	1	1	1	1	12	$466.14	$5,593.68
Monthly Service Ch														12	$292.56	$3,510.72
LVDS - kW		1,022	931	858	664	503	398	399	401	472	600	725	933	7,905	$1.944	$15,367.32
Espanola TS - M2																
2717713018																
	average															
Meter		1	1	1	1	1	1	1	1	1	1	1	1	12	$466.14	$5,593.68
Monthly Service Ch														12	$292.56	$3,510.72
Specific ST Lines - km		2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	30	$633.28	$18,998.40
Massey ME																
449121000																
	average															
Meter		1	1	1	1	1	1	1	1	1	1	1	1	12	$466.14	$5,593.68
Monthly Service Ch														12	$292.56	$3,510.72
Common ST Lines - kW		2,609	2,380	2,140	1,685	1,319	985	997	1,060	1,097	1,568	1,774	2,292	19,905	$0.67	$13,296.54
HVDS - Low - kW		2,609	2,380	2,140	1,685	1,319	985	997	1,060	1,097	1,568	1,774	2,292	19,905	$3.541	$70,483.61
																$229,288.81

Low Voltage Costs Allocated by Customer Class					
Customer Class	Retail Transmission Connection Rate ($)		Basis for Allocation ($)	Allocation Percentages	Allocated $
	per KWh	per kW			
Residential	0.0045		147,063	53.21%	121,998
GS < 50 kW	0.0042		47,317	17.12%	39,252
GS >50 kW		1.7889	78,808	28.51%	65,376
Sentinel Lights		1.2879	85	0.03%	71
Street Lighting		1.2616	2,228	0.81%	1,848
USL	0.0042		896	0.32%	743
TOTALS			276,397	100%	229,288

RATES - Low Voltage Adjustment						
Customer Class	LV Adj. Allocated	Calculated kWh	Calculated kW	Volumetric Rate Type	LV/ Adj. Rates/kWh	LV Adj. Rates/ kW
Residential	121,998	32,680,721	0	kWh	0.0037	
GS < 50 kW	39,252	11,265,899	0	kWh	0.0035	
GS >50 kW	65,376	17,442,772	44,054	kW		1.4840
Sentinel Lights	71	24,161	66	kW		1.0684
Street Lighting	1,848	623,166	1,766	kW		1.0466
USL	743	213,280	0	kWh	0.0035	
TOTALS	229,288	62,249,999	45,886			

b) ERHDC's actual low voltage charges are as follows:

2008 - $ 139,321
2009 - $ 140,975
2010 - $135,663
2011 - $203,607

Question # 24

Ref: Exhibit 8/ Tab 1/ Schedule 5 – Retail Transmission Service Rates (RTSR)

On page 6 of the above reference, it appears that Hydro One Sub-Transmission Rate Rider 6A were included in the RTSR calculation. Board staff notes that in accordance with the Rate Order for Hydro One Networks Inc. (EB-2009-0096), December 17, 2010, these rate riders were expired as of December 31, 2011. Please update the proposed RTSR by excluding these expired rate riders.

ERHDC Response

ERHDC has updated the rate riders to exclude the Hydro One Sub-Transmission Rate Rider 6A. ERHDC has filed with the interrogatory responses an updated RTSR model. The proposed rate riders are as follows:

Network Transmission Rates

Rate Class	Original Application	Revised to exclude Rate Rider 6A
Residential	$0.0057	$0.0056
GS<50 kW	$0.0053	$0.0052
GS>50kW	$2.1260	$2.0890
GS>50kW –Interval Metered	$2.3898	$2.3482
USL	$0.0053	$0.0052
Sentinel Lighting	$1.6116	$1.5835
Street Lighting	$1.6035	$1.5755

Retail Transmission Rates

Rate Class	Original Application	Revised to exclude Rate Rider 6A
Residential	$0.0040	$0.0041
GS<50 kW	$0.0036	$0.0037
GS>50kW	$1.4146	$1.4334
GS>50kW –Interval Metered	$1.9594	$1.9855
USL	$0.0036	$0.0037
Sentinel Lighting	$1.1164	$1.1312
Street Lighting	$1.0935	$1.1080

Question # 25

Ref: Exhibit 8/ Tab 1/ Schedule 6 – Loss Factors

a) ERHDC is proposing to set the 2012 Total Loss Factor (TLF) at 1.0714, and this is an increase from its current approved TLF of 1.0543. The underlying Distribution Loss Factor (DLF) in ERHDC's proposal is 1.0527. Board staff notes that this is high for a distributor with a compact service territory as is the case with ERHDC. Please describe any steps that are contemplated to decrease ERHDC's DLF, and as a result decrease the TLF, during the test year (2012) and beyond.

b) ERHDC is embedded within Hydro One. Please confirm whether ERHDC is fully embedded or partially embedded, and if the latter please provide the percentage of embedment.

ERHDC Response

a) ERHDC's service territory is not compact. ERHDC's total service territory is 99 sq. kilometers of which 73 kilometers are rural and 23 kilometers are urban. In addition, ERHDC's distribution voltage is a 4.16 kv which results in higher losses as compared to a utility with a higher distribution voltage.

b) ERHDC is fully embedded within Hydro One.

Question #26

Ref: Exhibit 8/ Tab 2/ Schedule 5 – Rate Mitigation

On page 1, it states: "As part of this mitigation plan, and since residential rate impacts are slightly higher than 10%, ERHDC proposes to recover the Smart Meter Disposition Rider and Stranded Meter Rate Rider over a 2 year period from May 1, 2102 to April 30, 2014. ERHDC also proposes to recover the LRAM claim over a 3 year period to mitigate the rate impacts to customer for conservation and demand management programs. ERHDC requests the rate rider to be effective from May 1, 2102 to April 30, 2015. "

a) Please provide the total bill impact for the residential class if the recovery period for the smart meter disposition rider and the stranded meter rate rider change from a 2 year period to a 3 year period.
b) Please provide the total bill impact for the residential class if the recovery period for the smart meter disposition rider, stranded meter rate rider and LRAM change to a 4 year period.
c) Please provide the total bill impact for the residential class if the recovery period for the deferral and variance rate rider change from a 1 year period to a 3 year period.

ERHDC Response

The bill impacts below are after adjustments to the revenue requirement, rate base, PILs, smart meter model, low voltage rate rider, cost allocation and RTSR rates as a result of the interrogatories. The adjustments are detailed in question #36.

a) The bill impact for the residential class if the recovery period for the smart meter disposition rate rider and the stranded meter rate rider charge was changed from a 2 year period to a 3 year period is below:

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Espanola Regional Hydro Distribution Corporation
File Number: EB-2001-0319
Rate Year: 2012

Residential

Consumption 800 kWh

	Charge Unit	Current Board-Approved			Proposed			Impact	
		Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	monthly	$ 9.9600	1	$ 9.96	$ 13.7000	1	$ 13.70	$ 3.74	37.55%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.5200	1	$ 1.52	$ 0.52	52.00%
Service Charge Rate Adder(s)	monthly	$ 0.1800	1	$ 0.18		1	$ -	-$ 0.18	-100.00%
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0120	800	$ 9.60	$ 0.0165	800	$ 13.20	$ 3.60	37.50%
Low Voltage Rate Adder	per kWh	$ 0.0023	800	$ 1.84	$ 0.0037	800	$ 2.96	$ 1.12	60.87%
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -	$ 0.0016	800	$ 1.28	$ 1.28	
Deferral/Variance Account Disposition Rate Rider			800	$ -	$ 0.0017	800	$ 1.36	$ 1.36	
Stranded Meter Rate Rider	monthly			$ -	$ 0.6900	1	$ 0.69	$ 0.69	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 22.58**			**$ 34.71**	**$ 12.13**	**53.72%**
RTSR - Network	per kWh	$ 0.0058	843.44	$ 4.89	$ 0.0056	857.12	$ 4.80	-$ 0.09	-1.88%
RTSR - Line and Transformation Connection	per kWh	$ 0.0041	843.44	$ 3.46	$ 0.0041	857.12	$ 3.51	$ 0.06	1.62%
Sub-Total B - Delivery (including Sub-Total A)				**$ 30.93**			**$ 43.02**	**$ 12.09**	**39.10%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	843.44	$ 4.39	$ 0.0052	857.12	$ 4.46	$ 0.07	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	843.44	$ 1.10	$ 0.0011	857.12	$ 0.94	-$ 0.15	-14.01%
Special Purpose Charge			843.44	$ -		857.12	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	843.44	$ 5.90	$ 0.0070	857.12	$ 6.00	$ 0.10	1.62%
Energy	per kWh	$ 0.0757	843.44	$ 63.85	$ 0.0757	857.12	$ 64.88	$ 1.04	1.62%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 106.16**			**$ 119.31**	**$ 13.14**	**12.38%**
HST		13%		$ 13.80	13%		$ 15.51	$ 1.71	12.38%
Total Bill (including Sub-total B)				**$ 119.97**			**$ 134.82**	**$ 14.85**	**12.38%**
Loss Factor (%)	**Note 1**	5.43%			7.14%				

b) The total bill impact for the residential class if the recovery period for the smart meter disposition rider, stranded meter rate rider and LRAM change to a 4 year period is below:

Residential

Consumption 800 **kWh**

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 9.9600	1	$ 9.96	$ 13.7000	1	$ 13.70	$ 3.74	37.55%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 1.1400	1	$ 1.14	$ 0.14	14.00%
Service Charge Rate Adder(s)	monthly	$ 0.1800	1	$ 0.18		1	$ -	-$ 0.18	-100.00%
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0120	800	$ 9.60	$ 0.0165	800	$ 13.20	$ 3.60	37.50%
Low Voltage Rate Adder	per kWh	$ 0.0023	800	$ 1.84	$ 0.0037	800	$ 2.96	$ 1.12	60.87%
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -	$ 0.0012	800	$ 0.96	$ 0.96	
Deferral/Variance Account Disposition Rate Rider			800	$ -	$ 0.0017	800	$ 1.36	$ 1.36	
Stranded Meter Rate Rider	monthly			$ -	$ 0.5200	1	$ 0.52	$ 0.52	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				**$ 22.58**			**$ 33.84**	**$ 11.26**	**49.87%**
RTSR - Network	per kWh	$ 0.0058	843.44	$ 4.89	$ 0.0056	857.12	$ 4.80	-$ 0.09	-1.88%
RTSR - Line and Transformation Connection	per kWh	$ 0.0041	843.44	$ 3.46	$ 0.0041	857.12	$ 3.51	$ 0.06	1.62%
Sub-Total B - Delivery (including Sub-Total A)				**$ 30.93**			**$ 42.15**	**$ 11.22**	**36.29%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	843.44	$ 4.39	$ 0.0052	857.12	$ 4.46	$ 0.07	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	843.44	$ 1.10	$ 0.0011	857.12	$ 0.94	-$ 0.15	-14.01%
Special Purpose Charge			843.44	$ -		857.12	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	843.44	$ 5.90	$ 0.0070	857.12	$ 6.00	$ 0.10	1.62%
Energy	per kWh	$ 0.0757	843.44	$ 63.85	$ 0.0757	857.12	$ 64.88	$ 1.04	1.62%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				**$ 106.16**			**$ 118.44**	**$ 12.27**	**11.56%**
HST		13%		$ 13.80	13%		$ 15.40	$ 1.60	11.56%
Total Bill (including Sub-total B)				**$ 119.97**			**$ 133.83**	**$ 13.86**	**11.55%**
Loss Factor (%)	**Note 1**	5.43%			7.14%				

c) The total bill impact for the residential class if the recovery period for the deferral and variance rate rider change from a 1 year period to a 3 year period is below:

Residential

Consumption 800 kWh

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	monthly	$ 9.9600	1	$ 9.96	$ 13.7000	1	$ 13.70	$ 3.74	37.55%
Smart Meter Rate Adder	monthly	$ 1.0000	1	$ 1.00	$ 2.2800	1	$ 2.28	$ 1.28	128.00%
Service Charge Rate Adder(s)	monthly	$ 0.1800	1	$ 0.18		1	$ -	-$ 0.18	-100.00%
Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0120	800	$ 9.60	$ 0.0165	800	$ 13.20	$ 3.60	37.50%
Low Voltage Rate Adder	per kWh	$ 0.0023	800	$ 1.84	$ 0.0037	800	$ 2.96	$ 1.12	60.87%
Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
LRAM & SSM Rate Rider			800	$ -	$ 0.0016	800	$ 1.28	$ 1.28	
Deferral/Variance Account Disposition Rate Rider			800	$ -	$ 0.0006	800	$ 0.48	$ 0.48	
Stranded Meter Rate Rider	monthly			$ -	$ 1.0400	1	$ 1.04	$ 1.04	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Sub-Total A - Distribution				$ 22.58			$ 34.94	$ 12.36	54.74%
RTSR - Network	per kWh	$ 0.0058	843.44	$ 4.89	$ 0.0056	857.12	$ 4.80	-$ 0.09	-1.88%
RTSR - Line and Transformation Connection	per kWh	$ 0.0041	843.44	$ 3.46	$ 0.0041	857.12	$ 3.51	$ 0.06	1.62%
Sub-Total B - Delivery (including Sub-Total A)				$ 30.93			$ 43.25	$ 12.32	39.84%
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	843.44	$ 4.39	$ 0.0052	857.12	$ 4.46	$ 0.07	1.62%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	843.44	$ 1.10	$ 0.0011	857.12	$ 0.94	-$ 0.15	-14.01%
Special Purpose Charge			843.44	$ -		857.12	$ -	$ -	
Standard Supply Service Charge			1	$ -		1	$ -	$ -	
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	843.44	$ 5.90	$ 0.0070	857.12	$ 6.00	$ 0.10	1.62%
Energy	per kWh	$ 0.0757	843.44	$ 63.85	$ 0.0757	857.12	$ 64.88	$ 1.04	1.62%
				$ -			$ -	$ -	
				$ -			$ -	$ -	
Total Bill (before Taxes)				$ 106.16			$ 119.54	$ 13.37	12.60%
HST		13%		$ 13.80	13%		$ 15.54	$ 1.74	12.60%
Total Bill (including Sub-total B)				$ 119.97			$ 135.08	$ 15.11	12.59%

Question # 27

LRAM

Ref: Exhibit 9/ Tab 3/ Schedule 1/ Page 1-5 ,Manager Summary – LRAM

ERHDC has requested an LRAM recovery for a total amount of $160,270, which includes $8,740 of carrying charges, for lost revenues incurred from 2006-2010 CDM programs.

a) Please confirm that ERHDC has used final 2010 program evaluation results from the OPA to calculate its LRAM amount.

b) If ERHDC did not use final 2010 program evaluation results from the OPA, please explain why and update the LRAM amount accordingly.

c) Please discuss if ERHDC has collected any LRAM amounts in the past. If ERHDC has collected LRAM in the past, please provide a table that shows the LRAM amounts collected historically.

d) Please confirm that ERHDC has not received any of the lost revenues requested in this application in the past. If ERHDC has collected lost revenues related to programs applied for in this application, please discuss the appropriateness of this request.

e) Please confirm that ERHDC is not requesting LRAM for any third tranche CDM programs.

f) Please provide a table that shows the LRAM amounts requested in this application by the year they are associated with and the year the lost revenues took place. Please provide separate tables for each rate class. Use the table below as an example and continue for all the years LRAM is requested:

Program Years	Residential - Years that lost revenues took place				
	2006	2007	2008	2009	2010
2006	$xxx	$xxx	$xxx	$xxx	$xxx
2007		$xxx	$xxx	$xxx	$xxx

2008			$xxx	$xxx	$xxx
2009				$xxx	$xxx
2010					$xxx

g) Please provide a table that shows the monthly LRAM balances, the Board-approved carrying charge rate and the total carrying charges by month for the duration of this LRAM request to support your request for carrying charges. Use the table below as an example:

Year	Month	Monthly Lost Revenue	Closing Balance	Interest Rate	Interest $

h) Please confirm that ERHDC is not requesting any SSM amount.

<u>ERHDC Response</u>

a) ERHDC confirms the final 2010 program results from the OPA were used to calculate the LRAM amount

b) Not applicable – 2010 final OPA results were used.

c) ERHDC has not collected any LRAM amounts in the past.

d) ERHDC has not received any of the lost revenues requested in this application in the past.

e) ERHDC confirms it is not requesting LRAM for any third tranche CDM program.

f) ERHDC has provided below a table that shows the LRAM amounts requested in this application by the year they are associated with and the year the lost revenues took place.

Table 1. Residential rate class LRAM claims

Program Years	2006	2007	2008	2009	2010	2011	Jan 1 - Apr 30 2012
2006	$4,607	$4,557	$4,720	$4,528	$651	$643	$146
2007		$32,670	$33,075	$31,636	$26,173	$1,726	$415
2008			$2,577	$2,465	$2,040	$2,017	$457
2009				$1,229	$995	$984	$244
2010					$484	$478	$119
Total	$4,607	$37,227	$40,371	$39,858	$30,342	$5,849	$1,379

Table 2. GS < 50 kW rate class LRAM claims

Program Years	2006	2007	2008	2009	2010	2011	Jan 1 - Apr 30 2012
2006	$0	$0	$0	$0	$0	$0	$0
2007		$0	$0	$0	$0	$0	$0
2008			$2	$2	$2	$2	$0
2009				$62	$53	$53	$13
2010					$200	$198	$49
Total	$0	$0	$2	$63	$255	$252	$62

g) Carrying charges are calculated using deferral and variance account rates prescribed by the OEB. These interest rates are annual rates but are updated quarterly. As such, LRAM is not calculated on lost revenue per month but on lost revenue per quarter. The table below provides quarterly LRAM balances, the Board-approved carrying charge rate (converted from a rate compounded annually to a rate compounded quarterly), and the total carrying charges by quarter for the duration of the LRAM request. Carrying charges are only calculated on the principle amount and are not compounded.

LRAM and carrying charges by quarter

Year	Quarter	Quarterly lost revenue	Closing balance	OEB-prescribed rate (quarterly)	Carrying charge
2006	Q1	$997	$997	1.56%	$16
2006	Q2	$997	$1,994	1.04%	$21
2006	Q3	$997	$2,991	1.15%	$34
2006	Q4	$997	$3,988	1.15%	$46
2007	Q1	$8,393	$12,382	1.15%	$142
2007	Q2	$8,393	$20,775	1.15%	$238
2007	Q3	$8,393	$29,168	1.15%	$335
2007	Q4	$8,393	$37,562	1.29%	$483
2008	Q1	$9,505	$47,067	1.29%	$605
2008	Q2	$9,505	$56,572	1.02%	$577
2008	Q3	$9,505	$66,076	0.84%	$553
2008	Q4	$9,505	$75,581	0.84%	$633
2009	Q1	$9,664	$85,245	0.61%	$522
2009	Q2	$9,664	$94,909	0.25%	$237
2009	Q3	$9,664	$104,573	0.14%	$144
2009	Q4	$9,664	$114,237	0.14%	$157
2010	Q1	$7,461	$121,697	0.14%	$167
2010	Q2	$7,461	$129,158	0.14%	$178
2010	Q3	$7,461	$136,618	0.22%	$304
2010	Q4	$7,461	$144,079	0.30%	$432
2011	Q1	$1,504	$145,583	0.37%	$535
2011	Q2	$1,504	$147,087	0.37%	$541
2011	Q3	$1,504	$148,591	0.37%	$546
2011	Q4	$1,504	$150,096	0.37%	$552
2012	Q1	$1,435	$151,530	0.49%	$742
			$151,530		$8,740
LRAM plus carrying charges					$160,270

h) ERHDC confirms it is not requesting is SSM amount.

Question # 28

Ref: Exhibit 9/ Tab 3/ Schedule 1/ Page 1, Manager's Summary – LRAM

ERHDC notes that none of the load reductions estimated for CDM programs were factored into the load forecast underpinning 2006, 2007, 2008, 2009, 2010 or 2011 rates.

Section 5.2 of the CDM Guidelines (EB-2008-0037) which are still applicable for the legacy period, state that lost revenues are only accruable until new rates, based on a new revenue requirement and load forecast, are set by the Board, as the savings would be assumed to be incorporated in the load forecast at that time.

a) Please identify the CDM savings that were proposed to be included in ERHDC's last Board approved load forecast (2008). If no CDM savings were included, please explain why and reconcile your response with section 5.2 of the CDM Guidelines and the Board's decision on Whitby Hydro's LRAM request in its 2012 IRM application (EB-2011-0206) where LRAM for the test year was disallowed as the Board found that the CDM impacts should have been included in the distributor's load forecast upon rebasing.

ERHDC Response

ERHDC did not include any CDM savings in the last Board approved load forecast in 2008.

ERHDC's 2008 Cost of Service rate application was filed November 6, 2007 and thus predates the 2008 CDM Guidelines which were released on March 28, 2008. Therefore, at the time of the filing ERHDC's 2008 COS and all supporting evidence, the rules associated with LRAM claims, including the rule specifying that lost revenues are only accruable until new rates are set by the Board, were not established.

The Whitby Hydro decision (EB-2011-0206) in which the Board denied LRAM claims for unforecasted saving were based on the CDM Guidelines, which again were developed after the filing of ERHDC's COS application.

Since ERHDC's 2008 COS application predates the 2008 CDM Guidelines, ERHDC should not be held at fault for not upholding the specific rules within it. In ERHDC situation, it should be the underlying principles of LRAM mechanism that should prevail. The principles of LRAM are to keep the LDC revenue neutral and to ensure that there is not a disincentive to the LDC in delivering energy savings to customers through CDM programs.

ERHDC agrees that once the savings are incorporated into the load forecast, there will be lost revenue associated with those savings. However, savings from 2005-2008 programs by ERHDC were not included in ERHDC 2008 load forecast. It is not reasonable to suggest that lost revenues from these programs should not be recoverable when final results from these programs were not incorporated into the load forecast and Guidelines specifying that CDM savings should be included into the load forecast were not yet established.

ERHDC notes that in PUC Distribution's decision (EB-2011-0101) a similar situation was addressed where a distributor filed a 2008 COS application that predated the CDM Guidelines. The Board stated *"The approved LRAM claim is comprised of lost revenues over the 2005 to 2010 period arising from CDM programs implemented from 2005 to 2010. Although the CDM guidelines states that lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the savings would assume to be incorporated in the load forecast at the time, the Board has acknowledged (Powerstream decision EB-2011-0005) that 2004 NAC based load forecast underpinning PUC's 2008 cost of service rates does not include the impact of PUC's CDM programs.".*

Question # 29

Smart Meters

Ref: Exhibit 9 /Tab 2/ Schedule 1/ Page 12 – Smart Meter Continuity Schedule

In Table 9-9, ERHDC shows a total of 404 smart meters have been installed for the GS<50 kW class as of December 31, 2010. However, in reference to Exhibit 9/ Tab 2/ Schedule 4/ page 4, ERHDC documented 387 smart meters have been installed for the GS<50 kW class as of 2010. Please explain this difference and ensure that the costs incurred in the installation of smart meters correspond to the number of the installed smart meters.

ERHDC Response

The installed number of meters is misstated. The metering department included a code in error for multi-residential customer with residential customers instead of GS<50 kW rate class. The correct number of meters installed by rate class is listed below. ERHDC will re-calculate the SMDR by rate class to reflect the correct number of meters installed.

	Number of Meters Installed
Residential	2,857
GS < 50 kW	426
GS > 50 kW	24

Question # 30

Ref: Exhibit 9 /Tab 2/ Schedule 4/ Page 9 – Smart Meter Model

On Sheet 3 of the Smart Meter Model, ERHDC has provided its cost of capital parameters for the years 2006 through 2012.

a) On sheet 3, in cell G23, ERHDC has input a debt capitalization of 56% for 2006. In its 2006 EDR application (RP-2005-0020/EB-2005-0362), ERHDC had rates approved on a deemed debt capitalization of 50%. Please explain the reason for using a different debt capitalization than that approved. Otherwise, please update the model.

b) On sheet 3, in cell G30, ERHDC shows a long-term debt rate of 5.80%. It also has documented an ROE of 8.60% for 2006. A review of the 2006 EDR model used for final rate setting shows that ERHDC was approved a debt rate of 5.00% and an ROE of 9.00%. Please explain ERHDC's inputs. Otherwise, please update the model. Note that these inputs would also be carried forward to 2007.

c) For 2008, Board staff observes that the ROE and deemed short-term correspond with what ERHDC was approved in its cost of service rebasing application (EB-2007-0901). On sheet 3, ERHDC shows a long-term debt rate of 6.10% for 2008; however in its decision (EB-2007-0901), the Board approved a long-term debt rate of 5.82%. Please explain ERHDC's inputs. Otherwise, please update the model.

d) In 2009, 2010, 2011 and 2012, it appears that ERHDC has updated the cost of capital parameters with those announced by the Board for May 1 rates in each year. However, these changes in the cost of capital parameters apply for rates rebased through a cost of service application. ERHDC has had its rates adjusted through the IRM adjustment process in each year. The Board's policy and practice is that the cost of capital parameters from the last approved cost of service application continue until the next rebasing application. Please explain ERHDC's inputs. Otherwise, please update the model.

ERHDC has used the maximum taxes/PILs rates input on sheet 3, row 40, for the years 2006, 2007, 2008, 2009, 2010, 2011 and 2012 and beyond. These are summarized in the following table:

Year	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012 and beyond**

Aggregate Federal and provincial income tax rate	36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%

e) Please confirm that these are the tax rates corresponding to the taxes or PILs actually paid by ERHDC in each of the historical years, and that ERHDC forecasts it will pay for 2012. For historical years to 2011, these would be the aggregate rate derived for calculating the taxes/PILs included in the revenue requirement in cost of service applications, or as calculated in taxes/PILs calculations as part of IRM applications. Otherwise, please explain the tax rates entered and their derivation.

ERHDC Response

a) ERHDC will update the model to reflect the approved deemed debt capitalization rate of 50% for 2006.

b) ERHDC will update the model to reflect the approved long-term debt rate of 5.00% and ROE of 9.00% in 2006 and carry forward to 2007.

c) ERHDC will update the model to reflect the approved long-term debt rate of 5.82%.

d) ERHDC will adjust the model to reflect the approved 2008 cost of capital parameters in 2009, 2010, 2011 and 2012.

e) ERHDC confirms the tax rates correspond to the taxes or PILs paid.

<u>Question # 31</u>

Ref: Exhibit 9 / Tab 2/ Schedule 4/ Page 17 – Smart Meter Model

In the Smart Meter Model Version 2.17 filed by ERHDC, the utility has relied upon sheet 8B to calculate the interest on OM&A and depreciation/amortization expenses. Sheet 8B calculates the interest based on the average annual balance of deferred OM&A and depreciation/amortization expenses based on the annual amounts input elsewhere in the model.

The more accurate method for calculating the interest on OM&A and depreciation/amortization expense is to input the monthly amounts from the subaccount details of Account 1556, using sheet 8A of the model. This approach is analogous to the calculation of interest on SMFA revenues on sheet 8 of the model. Please re-file the smart meter model using the monthly OM&A and depreciation/amortization expense data from Account 1556 records. If this is not possible, please explain.

<u>ERHDC Response</u>

ERHDC has re-filed the model using the monthly amounts on sheet 8A for OM&A and depreciation/amortization.

Question #32

Ref: Exhibit 9/ Tab 2/ Schedule 1/ Page 3-4 - Security Audit

On page 4 of the application, ERHDC provides a description of its security audit as well as the procurement process used to select an audit partner. ERHDC states:

> Going forward, ERHDC has budgeted for a security audit, as this is a prudent approach to satisfying the due diligence requirements for protection not only of the customer information, but also to ensure that access to the infrastructure is properly protected...
>
> Therefore, ERHDC joined a consortium of Ontario Util-assist LDC customers in the issuance of the May 2010 "Smart Meter Network Security Audit Services" Request for Proposal.
>
> The objective of the RFP is to select an audit partner who would complete a security audit of the Sensus AMI systems for consortium members with Sensus technology in place, and to then work with Sensus towards the implementation of viable countermeasures to resolve all security concerns. The selected audit firm will first complete an in-depth security review at one participating utility that has the Sensus solution. Once the review is complete, the audit firm would then review the technology at all remaining participating utilities to confirm that their Sensus AMI systems are configured to the same standard as that declared as the standard for the audit group. Audits are anticipated to include end-to-end from the meter to utility systems and home area network.

a) Please confirm whether or not the RFP process has been completed and the audit partner has been selected.

b) If the audit partner has been selected, please provide the budgeted amount for the security audit for 2012. Please confirm whether or not the budgeted amount has been included as part of the 2012 OM&A costs.

ERHDC Response

a) The RFP process has been complete and the Bell Wurld Tech has been selected.

b) The budgeted amount for the security audit for 2012 included in OM&A is $5,000.

Question # 33

Ref: Exhibit 9/ Tab 2/ Schedule 3 – Smart Meter Disposition Rider (SMDR)

On page 2, ERHDC has provided a table showing the calculation of class-specific SMDRs.
Please confirm the allocator used to allocate costs to each class in ERHDC's SMDR calculations for the following:

i. Return (deemed interest plus return on equity);
ii. Amortization;
iii. OM&A;
iv. PILs; and
v. Smart Meter Rate Adder revenues

ERHDC Response

a) ERHDC used the following allocators to allocate costs by rate class when calculating SMDR:

   i. Return (deemed interest plus return on equity) – Number of smart meters installed by rate class.
   ii. Amortization – Smart meter costs by rate class.
   iii. OM&A – Number of smart meters installed by rate class.
   iv. PILs – revenue requirement by rate class before PILs
   v. Smart meter rate adder revenues – actual adders collected by rate class.

Question # 34

Ref: Exhibit 9/ Tab 2/ Schedule 1 – Smart Meter Program

In the above reference, ERHDC provides the detailed descriptions of initiatives within the smart meter program. The initiatives include:

- Security Audit;
- Operational Data Store (ODS);
- Business Process Redesign;
- System Changes;
- Integration with MDM/R;
- Transition to TOU pricing;
- Web Presentment; and

a) Please provide a breakdown of the costs in the following categories for each initiative.

	2011			2012		
	Capital Expenditures	OM&A		Capital Expenditures	OM&A	
		One-time	Ongoing		One-time	Ongoing
Security Audit						
ODS						
Business Process Redesign						
System Changes						
Integration with MDM/R						
Transition to TOU pricing						
Web Presentment						
Consumer Education Plan						

b) Please confirm how much of the above costs are included in the Smart Meter model in terms of calculating the SMDR. For the amounts that are not included in the SMDR calculation, please explain how the costs are proposed to be recovered.

ERHDC Response

	2011			2012		
	Capital Expenditures	OM&A		Capital Expenditures	OM&A	
		One-time	Ongoing		One-time	Ongoing
Security Audit	7,522					10,800
ODS			4,719			5,600
Business Process Redesign	2,000					
System Changes	5,99					
Integration with MDM/R	5,966					1,000
Transition to TOU pricing						
Web Presentment	9,487		1,000			1,000
Consumer Education Plan					11,000	
Sync Operator Services						24,250
Sensus operating fees			37,662			39,350

b) All of the above costs are included in the smart meter model and in the calculation of the SMDR.

Question # 35

Ref: Exhibit 9/ Tab 2/ Schedule 4 – Smart Meter Model

If ERHDC has changed its data inputs to the Smart Meter Model, version 2.17 as a result of interrogatories by Board staff and/or the intervenor, please update and re-file the smart meter model in working Microsoft Excel format.

ERHDC Response

ERHDC has adjusted the cost of capital parameters as in question #30, updated the model for monthly OM&A and depreciation amounts as in question #31and changed the number of meters reported as in question #29. ERHDC will submit as revised excel model with the interrogatory responses. As per the revised model ERHDC has recalculated the costs per rate class and the SMDR as follows:

Average Costs Per Meter by Rate Class		
Residential Meters		
Costs		Cost Per Meter
Total Capital Cost	547,188	
Number of Meters Installed	2,857	
Average Cost Per Meter		$ 191.53
General Service < 50kW		
Costs		Cost Per Meter
Total Capital Cost	107,240	
Number of Meters Installed	426	
Average Cost Per Meter		$ 251.74
General Service > 50kW		
Costs		Cost Per Meter
Total Capital Cost	21,478	
Number of Meters Installed	24	
Average Cost Per Meter		$ 894.92

Smart Meter Actual Cost Recovery Rate Rider - SMDR Calculated by Rate Class				
	Total	Residential	GS < 50	GS > 50
Allocators				
Average Smart Meter Unit Cost		$ 191.53	$ 251.74	$ 894.92
Smart Meter Cost	$ 675,907	$ 547,188	$ 107,240	$ 21,478
Allocation of Smart Meter Costs	100.00%	80.96%	15.87%	3.18%
Number of meters installed	3,307	2,857	426	24
Allocation of Number of meters installed	100.00%	86.39%	12.88%	0.73%
Total Return (deemed interest plus return on equity)	$ 96,687	$ 83,530	$ 12,455	$ 702
Amortization	$ 107,917	$ 87,365	$ 17,122	$ 3,429
OM&A	$ 106,633	$ 92,123	$ 13,736	$ 774
Revenue Requirement before PILs	$ 311,237	$ 263,018	$ 43,313	$ 4,905
PILs	$ 16,573	$ 14,005	$ 2,306	$ 261
Total Revenue Requirement 2006 to 2011	$ 327,810	$ 277,024	$ 45,620	$ 5,166
	100.00%	84.51%	13.92%	1.58%
Smart Meter Rate Adder Revenues	($141,740)	($122,274)	($18,455)	($1,011)
Carrying Charge SMFA	($5,422)	($4,677)	($706)	($39)
Carrying Charge Deferred Expenses	$3,444	$2,910	$479	$54
Smart Meter True-up	$ 184,091	$ 155,571	$ 25,619	$ 2,452
Metered Customers per 2012 test year forecast	3,299	2,847	425	27
Rate Rider to Recover Smart Meter Costs (per month)	$ 4.65	$ 4.55	$ 5.02	$ 7.57
2 Year Rate Rider (per customer per month)	2.33	2.28	2.51	3.78

Question # 36

Miscellaneous **Ref: Revenue Requirement Work Form (RRWF)**

a) Please re-file the RRWF using version 2.20. ERHDC should show its original application in column E of Sheet "3.Data_Input_Sheet".
b) Based on the responses to the interrogatories from all parties, please submit a Microsoft Excel file containing an updated RRWF that represents any changes the applicant wishes to make to the amounts in the previous version of the RRWF. Column E of Sheet 3 should remain unchanged. Instead, adjustments or changed numbers should be input into cells on columns I or M, as applicable.
c) Please provide a list of all changes made to ERHDC's original application (by exhibit), including an updated derivation of its revenue requirement, PILs calculation, base rates, rate adders/riders, and bill impacts.

ERHDC Response

a) ERHDC will re-file with the interrogatory responses an updated RRWF.
b) ERHDC has adjusted the RRWF as required.
c) As a result of the interrogatory responses ERHDC has updated the following areas:

Exhibit 2 - Rate Base

ERHDC increased the rate base by $12,711.

The amount represents the increase in cost of power of $84,744 for the underestimation of Low Voltage Charges as per question #23. ($84,744 x 15% working capital allowance = $12,711)

Exhibit 3 – Operating Costs

ERHDC decreased depreciation by $2,324.

ERHDC increased the reduction to depreciation expense as a result of the PP&E deferral account and transition to IFRS by $2,325 as per question #40.

ERHDC decrease PILS by $847

ERHDC decreased the PILs requirement based on the decreased revenue amount from the interrogatory updates.

Exhibit 5 – Cost of Capital and Rate of Return

ERHDC updated the capital structure and the rate base calculations for 2012 based on the cost of capital parameters issued by the OEB for 2012 cost of service rate applications.

ROE – 9.12%
Deemed LT Debt Rate – 4.41%
Deemed ST Debt Rate – 2.08%

2012		
Description	**Deemed Portion**	**Effective Rate**
Long-Term Debt	56.00%	4.41%
Short-Tern Debt	4.00%	2.08%
Return On Equity	40.00%	9.12%
Weighted Debt Rate		4.25%
Regulated Rate of Return		6.20%

WORKING CAPITAL ALLOWANCE FOR 2012	
Distribution Expenses	
Distribution Expenses - Operation	249,346
Distribution Expenses - Maintenance	397,158
Billing and Collecting	371,722
Community Relations	1,000
Administrative and General Expenses	353,398
Taxes Other than Income Taxes	-
Less: Capital Taxes within 6105	-
Total Eligible Distribution Expenses	**1,372,624**
Power Supply Expenses	6,226,613
Total Working Capital Expenses	7,599,237
Working Capital Allowance rate of 15%	1,139,885

RATE BASE CALCULATION FOR 2012	
Fixed Assets Opening Balance 2012 (IFRS)	3,062,546
Fixed Assets Closing Balance 2012 (IFRS)	3,150,903
Average Fixed Asset Balance for 2012	3,106,725
Working Capital Allowance	1,139,885
Rate Base	4,246,610
Regulated Rate of Return	6.20%
Regulated Return on Capital	263,324
Deemed Interest Expense	108,407
Deemed Return on Equity	154,916

Exhibit 6 – Revenue Deficiency or Surplus

ERHDC updated the revenue deficiency calculation and revised the original deficiency amount of $445,113 to $423,422. Refer to the schedule below:

Espanola Regional Hydro Distribution Corporation Revenue Deficiency Determination		
Description	**2012 Test Existing Rates**	**2012 Test - Required Revenue**
Revenue		
Revenue Deficiency		423,422
Distribution Revenue	1,225,251	1,225,251
Other Operating Revenue (Net)	139,899	139,899
Total Revenue	**1,365,150**	**1,788,572**
Costs and Expenses		
Administrative & General, Billing & Collecting	726,120	726,120
Operation & Maintenance	646,504	646,504
Depreciation & Amortization	143,296	143,296
Property Taxes	0	0
Capital Taxes	0	0
Deemed Interest	108,407	108,407
Total Costs and Expenses	**1,624,327**	**1,624,327**
Less OCT Included Above	0	0
Total Costs and Expenses Net of OCT	**1,624,327**	**1,624,327**
Utility Income Before Income Taxes	**(259,177)**	**164,245**
Income Taxes:		
Corporate Income Taxes	9,329	9,329
Total Income Taxes	**9,329**	**9,329**
Utility Net Income	**(268,506)**	**154,917**
Capital Tax Expense Calculation:		
Total Rate Base	4,246,610	4,246,610
Exemption	15,000,000	15,000,000
Deemed Taxable Capital	**(10,753,390)**	**(10,753,390)**
Ontario Capital Tax	0	0
Income Tax Expense Calculation:		
Accounting Income	(259,177)	164,245
Tax Adjustments to Accounting Income	(104,059)	(104,059)
Taxable Income	**(363,236)**	**60,186**
Income Tax Expense	(56,302)	9,329
Tax Rate Refecting Tax Credits	15.50%	15.50%
Actual Return on Rate Base:		
Rate Base	4,246,610	4,246,610
Interest Expense	108,407	108,407
Net Income	(268,506)	154,917
Total Actual Return on Rate Base	**(160,098)**	**263,324**
Actual Return on Rate Base	-3.77%	6.20%
Required Return on Rate Base:		
Rate Base	4,246,610	4,246,610
Return Rates:		
Return on Debt (Weighted)	4.25%	4.25%
Return on Equity	9.42%	9.42%
Deemed Interest Expense	108,407	108,407
Return On Equity	154,916	154,916
Total Return	**263,324**	**263,324**
Expected Return on Rate Base	6.20%	6.20%
Revenue Deficiency After Tax	**423,422**	**(0)**
Revenue Deficiency Before Tax	**423,422**	**(0)**

Tax Exhibit		**2012**
Deemed Utility Income		154,916
Tax Adjustments to Accounting Income		(104,059)
Taxable Income prior to adjusting revenue to PILs		**50,857**
Tax Rate		15.50%
Total PILs before gross up		**7,883**
Grossed up PILs		**9,329**

Exhibit 7 – Cost Allocation

ERHDC revised the cost allocation model for the revised demand data in I8 and the update to the smart meter cost allocations. The result was 0.1% change in allocation to the residential customer rate class.

Cost Allocation Based Calculations

Class	Revenue Requirement - 2012 Cost Allocation Model	2012 Base Revenue Allocated based on Proportion of Revenue at Existing Rates	Miscellaneous Revenue Allocated from 2012 Cost Allocation Model	Total Revenue	Revenue Cost Ratio	Proposed Revenue to Cost Ratio	Proposed Revenue	Miscellaneous Revenue	Proposed Base Revenue	Board Target Low	Board Target High
Residential	1,157,917	985,560	94,675	1,080,235	93.3%	95.2%	1,101,882	94,675	1,007,207	85%	115%
GS < 50 kW	322,809	346,021	22,553	368,574	114.2%	115.9%	374,136	22,553	351,583	80%	120%
GS >50 kW	187,066	241,975	11,696	253,671	135.6%	120.0%	224,479	11,696	212,783	80%	120%
Sentinel Lights	2,503	1,462	246	1,708	68.2%	80.0%	2,002	246	1,756	80%	120%
Street Lighting	110,975	65,855	10,187	76,042	68.5%	70.0%	77,683	10,187	67,496	70%	120%
USL	7,302	7,800	542	8,342	114.2%	114.9%	8,390	542	7,848	80%	120%
TOTAL	1,788,572	1,648,673	139,899	1,788,572	100.0%		1,788,572	139,899	1,648,673		

Exhibit 8 – Rate Design

ERHDC revised the Low Voltage rate riders as per question #23.

ERHDC revised the Retail Transmission Service Rates as per question #24

The revised base revenue requirement is below:

Service Revenue Requirement	$	1,788,572
Less: Revenue Offsets	$	139,899
Total Base Revenue Requirement	$	1,648,673
Addback LV Charges	$	229,288
Addback Transformer Allowances	$	11,512
Gross Revenues For Rates	$	1,889,473

ERHDC did not change the allocation of the fixed and variable split. The updated rates are as follows:

Fixed Charge Analysis								
Customer Class	Current Volumetric Split	Current Fixed Charge Spilt	Total	Fixed Rate Based on Current Fixed/Variable Revenue Proportions	2011 Rates From OEB Approved Tariff	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)	Target Fixed Charge Split	Fixed Charge with Target Split
Residential	53.54%	46.46%	100.00%	13.70	9.96	19.73	46.46%	13.70
GS < 50 kW	64.40%	35.60%	100.00%	24.54	17.95	28.37	35.60%	24.54
GS >50 kW	70.93%	29.07%	100.00%	190.93	161.36	70.53	29.07%	190.93
Sentinel Lights	62.96%	37.04%	100.00%	2.09	1.29	7.70	37.04%	2.09
Street Lighting	63.85%	36.15%	100.00%	1.93	1.40	8.48	36.15%	1.93
USL	41.57%	58.43%	100.00%	11.94	8.82	14.22	58.43%	11.94

Distribution Rate Allocation Between Fixed & Variable Rates For 2012 Test Year										
Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Resulting Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
Residential	1,007,207	61.09%	13.70	$0.0165	$ 467,922	$ 539,285		1,007,207	121,998	1,129,205
GS < 50 kW	351,583	21.33%	24.54	$0.0201	$ 125,161	$ 226,422		351,583	39,252	390,835
GS >50 kW	212,783	12.91%	190.93	$3.6872	$ 61,861	$ 150,922	$ 11,512	224,295	65,376	289,672
Sentinel Lights	1,756	0.11%	2.09	$16.7548	$ 651	$ 1,106		1,756	71	1,827
Street Lighting	67,496	4.09%	1.93	$24.4048	$ 24,397	$ 43,099		67,496	1,848	69,344
USL	7,848	0.48%	11.94	$0.0153	$ 4,585	$ 3,263		7,848	743	8,591
TOTAL	**1,648,673**	**100%**			**$ 684,577**	**$ 964,096**	**$ 11,512**	**$ 1,660,185**	**$ 229,288**	**$ 1,889,473**
			Forecast Fixed/Variable Rati		**41.235%**	**58.072%**	**0.693%**	**100.000%**		

ERHDC has included the updated bill impacts below:

RESIDENTIAL

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
100 kWh	Monthly Service Charge			9.96			13.70	3.74	37.55%	40.49%
	Distribution (kWh)	100	0.0120	1.20	100	0.0165	1.65	0.45	37.50%	4.88%
	Low Voltage Rider (kWh)	100	0.0023	0.23	100	0.0037	0.37	0.14	60.87%	1.09%
	Smart Meter Disposition Rider (per month)			1.00			2.28	1.28	128.00%	6.74%
	Stranded Smart Meter Rate Rider (per month)						1.04	1.04		
	LRAM & SSM Rider (kWh)	100	0.0000	0.00	100	0.0016	0.16	0.16		0.47%
	Late Payment ($)		0.1800	0.18	0	0.0000	0.00	(0.18)		0.00%
	Deferrral & Variance Acct (kWh)	100	0.0000	0.00	100	0.0017	0.17	0.17		0.50%
	Distribution Sub-Total			**12.57**			**19.37**	**6.80**	**54.10%**	**57.25%**
	Retail Transmisssion (kWh)	105	0.0099	1.04	107	0.0097	1.04	(0.00)	(0.43%)	3.07%
	Delivery Sub-Total			**13.61**			**20.41**	**6.80**	**49.92%**	**60.33%**
	Other Charges (kWh)	105	0.0135	1.42	107	0.0133	1.42	0.00	0.12%	4.21%
	Cost of Power Commodity (kWh)	105	0.0757	7.98	107	0.0757	8.11	0.13	1.62%	23.96%
	Total Bill Before Taxes			**23.01**			**29.94**	**6.93**	**30.12%**	**88.50%**
	GST		13.00%	2.99		13.00%	3.89	0.90	30.10%	11.50%
	Total Bill			**26.00**			**33.83**	**7.83**	**30.12%**	**100.00%**

RESIDENTIAL

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
250 kWh	Monthly Service Charge			9.96			13.70	3.74	37.55%	24.58%
	Distribution (kWh)	250	0.0120	3.00	250	0.0165	4.13	1.13	37.50%	7.40%
	Low Voltage Rider (kWh)	250	0.0023	0.58	250	0.0037	0.93	0.35	60.87%	1.66%
	Smart Meter Disposition Rider (per month)			1.00			2.28	1.28	128.00%	4.09%
	Stranded Smart Meter Rate Rider (per month)						1.04	1.04		
	LRAM & SSM Rider (kWh)	250	0.0000	0.00	250	0.0016	0.40	0.40		0.72%
	Late Payment ($)		0.1800	0.18	0	0.0000	0.00	(0.18)		0.00%
	Deferrral & Variance Acct (kWh)	250	0.0000	0.00	250	0.0017	0.43	0.43		0.76%
	Distribution Sub-Total			**14.72**			**22.90**	**8.18**	**55.59%**	**41.08%**
	Retail Transmisssion (kWh)	264	0.0099	2.61	268	0.0097	2.60	(0.01)	(0.43%)	4.66%
	Delivery Sub-Total			**17.32**			**25.49**	**8.17**	**47.15%**	**45.74%**
	Other Charges (kWh)	264	0.0135	3.56	268	0.0133	3.56	0.00	0.12%	6.39%
	Cost of Power Commodity (kWh)	264	0.0757	19.94	268	0.0757	20.26	0.32	1.62%	36.36%
	Total Bill Before Taxes			**40.82**			**49.32**	**8.51**	**20.84%**	**88.50%**
	GST		13.00%	5.31		13.00%	6.41	1.10	20.81%	11.50%
	Total Bill			**46.13**			**55.73**	**9.61**	**20.84%**	**100.00%**

RESIDENTIAL

Consumption		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
500 kWh	Monthly Service Charge			9.96			13.70	3.74	37.55%	14.85%
	Distribution (kWh)	500	0.0120	6.00	500	0.0165	8.25	2.25	37.50%	8.95%
	Low Voltage Rider (kWh)	500	0.0023	1.15	500	0.0037	1.85	0.70	60.87%	2.01%
	Smart Meter Disposition Rider (per month)			1.00			2.28	1.28	128.00%	2.47%
	Stranded Smart Meter Rate Rider (per month)						1.04	1.04		
	LRAM & SSM Rider (kWh)	500	0.0000	0.00	500	0.0016	0.80	0.80		0.87%
	Late Payment ($)		0.1800	0.18	0	0.0000	0.00	(0.18)		0.00%
	Deferrral & Variance Acct (kWh)	500	0.0000	0.00	500	0.0017	0.85	0.85		0.92%
	Distribution Sub-Total			**18.29**			**28.77**	**10.48**	**57.30%**	**31.19%**
	Retail Transmisssion (kWh)	527	0.0099	5.22	536	0.0097	5.20	(0.02)	(0.43%)	5.63%
	Delivery Sub-Total			**23.51**			**33.97**	**10.46**	**44.48%**	**36.83%**
	Other Charges (kWh)	527	0.0135	7.12	536	0.0133	7.12	0.01	0.12%	7.73%
	Cost of Power Commodity (kWh)	527	0.0757	39.88	536	0.0757	40.53	0.65	1.62%	43.94%
	Total Bill Before Taxes			**70.50**			**81.62**	**11.14**	**15.79%**	**88.50%**
	GST		13.00%	9.17		13.00%	10.61	1.44	15.76%	11.50%
	Total Bill			**79.67**			**92.23**	**12.58**	**15.79%**	**100.00%**

RESIDENTIAL

Consumption: 680 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.96			13.70	3.74	37.55%	100.49%
Distribution (kWh)	680	0.0120	8.16	680	0.0165	11.22	3.06	37.50%	82.30%
Low Voltage Rider (kWh)	680	0.0023	1.56	680	0.0037	2.52	0.95	60.87%	18.45%
Smart Meter Disposition Rider (per month)			1.00			2.28	1.28	128.00%	16.72%
Stranded Smart Meter Rate Rider (per month)						1.04	1.04		
LRAM & SSM Rider (kWh)	680	0.0000	0.00	680	0.0016	1.09	1.09		0.92%
Late Payment ($)		0.1800	0.18	0	0.0000	0.00	(0.18)	(100.00%)	0.00%
Deferral & Variance Acct (kWh)	680	0.0000	0.00	680	0.0017	1.16	1.16		0.98%
Distribution Sub-Total			**20.86**			**33.00**	**12.14**	**58.17%**	**27.85%**
Retail Transmisssion (kWh)	717	0.0099	7.10	729	0.0097	7.07	(0.03)	(0.43%)	5.96%
Delivery Sub-Total			**27.96**			**40.07**	**12.11**	**43.29%**	**33.81%**
Other Charges (kWh)	717	0.0135	9.68	729	0.0133	9.69	0.01	0.12%	8.18%
Cost of Power Commodity (kWh)	717	0.0757	54.24	729	0.0757	55.11	0.88	1.62%	46.51%
Total Bill Before Taxes			**91.88**			**104.87**	**13.00**	**14.15%**	**88.50%**
GST		13.00%	11.94		13.00%	13.63	1.69	14.15%	11.50%
Total Bill			**103.82**			**118.50**	**14.69**	**14.15%**	**100.00%**

RESIDENTIAL

Consumption: 800 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.96			13.70	3.74	37.55%	10.07%
Distribution (kWh)	800	0.0120	9.60	800	0.0165	13.20	3.60	37.50%	9.70%
Low Voltage Rider (kWh)	800	0.0023	1.84	800	0.0037	2.96	1.12	60.87%	2.18%
Smart Meter Disposition Rider (per month)			1.00			2.28	1.28	128.00%	1.68%
Stranded Smart Meter Rate Rider (per month)						1.04	1.04		
LRAM & SSM Rider (kWh)	800	0.0000	0.00	800	0.0016	1.28	1.28		0.94%
Late Payment ($)		0.1800	0.18	0	0.0000	0.00	(0.18)		0.00%
Deferral & Variance Acct (kWh)	800	0.0000	0.00	800	0.0017	1.36	1.36		1.00%
Distribution Sub-Total			**22.58**			**35.82**	**13.24**	**58.64%**	**26.33%**
Retail Transmisssion (kWh)	843	0.0099	8.35	857	0.0097	8.31	(0.04)	(0.43%)	6.11%
Delivery Sub-Total			**30.93**			**44.13**	**13.20**	**42.69%**	**32.45%**
Other Charges (kWh)	843	0.0135	11.39	857	0.0133	11.40	0.01	0.12%	8.38%
Cost of Power Commodity (kWh)	843	0.0757	63.81	857	0.0757	64.84	1.03	1.62%	47.67%
Total Bill Before Taxes			**106.12**			**120.37**	**14.25**	**13.43%**	**88.50%**
GST		13.00%	13.80		13.00%	15.65	1.85	13.43%	11.50%
Total Bill			**119.92**			**136.02**	**16.10**	**13.43%**	**100.00%**

RESIDENTIAL

Consumption: 1,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.96			13.70	3.74	37.55%	8.29%
Distribution (kWh)	1,000	0.0120	12.00	1,000	0.0165	16.50	4.50	37.50%	9.99%
Low Voltage Rider (kWh)	1,000	0.0023	2.30	1,000	0.0037	3.70	1.40	60.87%	2.24%
Smart Meter Disposition Rider (per month)			1.00			2.28	1.28	128.00%	1.38%
Stranded Smart Meter Rate Rider (per month)						1.04	1.04		
LRAM & SSM Rider (kWh)	1,000	0.0000	0.00	1,000	0.0016	1.60	1.60		0.97%
Late Payment ($)		0.1800	0.18	0	0.0000	0.00	(0.18)		0.00%
Deferral & Variance Acct (kWh)	1,000	0.0000	0.00	1,000	0.0017	1.70	1.70		1.03%
Distribution Sub-Total			**25.44**			**40.52**	**15.08**	**59.28%**	**24.52%**
Retail Transmisssion (kWh)	1,054	0.0099	10.44	1,071	0.0097	10.39	(0.04)	(0.43%)	6.29%
Delivery Sub-Total			**35.88**			**50.91**	**15.04**	**41.91%**	**30.81%**
Other Charges (kWh)	1,054	0.0135	14.23	1,071	0.0133	14.25	0.02	0.12%	8.62%
Cost of Power Commodity (kWh)	1,054	0.0757	79.76	1,071	0.0757	81.05	1.29	1.62%	49.06%
Total Bill Before Taxes			**129.87**			**146.21**	**16.35**	**12.59%**	**88.50%**
GST		13.00%	16.88		13.00%	19.01	2.12	12.59%	11.50%
Total Bill			**146.75**			**165.22**	**18.47**	**12.59%**	**100.00%**

RESIDENTIAL

Consumption
1,500 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			9.96			13.70	3.74	37.55%	5.75%
Distribution (kWh)	1,500	0.0120	18.00	1,500	0.0165	24.75	6.75	37.50%	10.39%
Low Voltage Rider (kWh)	1,500	0.0023	3.45	1,500	0.0037	5.55	2.10	60.87%	2.33%
Smart Meter Disposition Rider (per month)			1.00			2.28	1.28	128.00%	0.96%
Stranded Smart Meter Rate Rider (per month)						1.04	1.04		
LRAM & SSM Rider (kWh)	1,500	0.0000	0.00	1,500	0.0016	2.40	2.40		1.01%
Late Payment ($)		0.1800	0.18	0	0.0000	0.00	(0.18)		0.00%
Deferrral & Variance Acct (kWh)	1,500	0.0000	0.00	1,500	0.0017	2.55	2.55		1.07%
Distribution Sub-Total			**32.59**			**52.27**	**19.68**	**60.39%**	**21.94%**
Retail Transmisssion (kWh)	1,581	0.0099	15.66	1,607	0.0097	15.59	(0.07)	(0.43%)	6.54%
Delivery Sub-Total			**48.25**			**67.86**	**19.61**	**40.65%**	**28.49%**
Other Charges (kWh)	1,581	0.0135	21.35	1,607	0.0133	21.37	0.02	0.12%	8.97%
Cost of Power Commodity (kWh)	1,581	0.0757	119.64	1,607	0.0757	121.58	1.94	1.62%	51.04%
Total Bill Before Taxes			**189.23**			**210.81**	**21.58**	**11.40%**	**88.50%**
GST		13.00%	24.60		13.00%	27.41	2.81	11.40%	11.50%
Total Bill			**213.83**			**238.22**	**24.38**	**11.40%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
2,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			17.95			24.54	6.59	36.71%	7.52%
Distribution (kWh)	2,000	0.0147	29.40	2,000	0.0201	40.20	10.80	36.73%	12.31%
Low Voltage Rider (kWh)	2,000	0.0021	4.20	2,000	0.0035	7.00	2.80	66.67%	2.14%
Smart Meter Disposition Rider (per month)			1.00			2.51	1.51	151.00%	0.77%
Stranded Smart Meter Rate Rider (per month)						1.37	1.37		
LRAM & SSM Rider ($)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00		0.00%
Late Payment (kWh)		0.4200	0.42	0	0.0000	0.00	(0.42)		0.00%
Deferrral & Variance Acct (kWh)	2,000	0.0000	0.00	2,000	0.0018	3.60	3.60		1.10%
Distribution Sub-Total			**52.97**			**79.22**	**26.25**	**49.56%**	**24.27%**
Retail Transmisssion (kWh)	2,109	0.0091	19.19	2,143	0.0089	19.07	(0.12)	(0.61%)	5.84%
Delivery Sub-Total			**72.16**			**98.29**	**26.13**	**36.22%**	**30.11%**
Other Charges (kWh)	2,109	0.0135	28.47	2,143	0.0133	28.50	0.03	0.12%	8.73%
Cost of Power Commodity (kWh)	2,109	0.0757	159.52	2,143	0.0757	162.10	2.59	1.62%	49.66%
Total Bill Before Taxes			**260.14**			**288.89**	**$28.75**	**11.05%**	**88.50%**
GST		13.00%	33.82		13.00%	37.56	3.74	11.05%	11.50%
Total Bill			**293.96**			**326.45**	**$32.49**	**11.05%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption
5,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			17.95			24.54	6.59	36.71%	3.20%
Distribution (kWh)	5,000	0.0147	73.50	5,000	0.0201	100.50	27.00	36.73%	13.09%
Low Voltage Rider (kWh)	5,000	0.0021	10.50	5,000	0.0035	17.50	7.00	66.67%	2.28%
Smart Meter Disposition Rider (per month)			1.00			2.51	1.51	151.00%	0.33%
Stranded Smart Meter Rate Rider (per month)						1.37	1.37		
LRAM & SSM Rider (kWh)	5,000	0.0000	0.00	5,000	0.0000	0.00	0.00		0.00%
Late Payment ($)		0.4200	0.42	0	0.0000	0.00	(0.42)		0.00%
Deferrral & Variance Acct (kWh)	5,000	0.0000	0.00	5,000	0.0018	9.00	9.00		1.17%
Distribution Sub-Total			**103.37**			**155.42**	**52.05**	**50.35%**	**20.24%**
Retail Transmisssion (kWh)	5,272	0.0091	47.97	5,357	0.0089	47.68	(0.29)	(0.61%)	6.21%
Delivery Sub-Total			**151.34**			**203.10**	**51.76**	**34.20%**	**26.45%**
Other Charges (kWh)	5,272	0.0135	71.17	5,357	0.0133	71.25	0.08	0.12%	9.28%
Cost of Power Commodity (kWh)	5,272	0.0757	398.79	5,357	0.0757	405.26	6.47	1.62%	52.77%
Total Bill Before Taxes			**621.29**			**679.60**	**$58.31**	**9.38%**	**88.50%**
GST		13.00%	80.77		13.00%	88.35	7.58	9.38%	11.50%
Total Bill			**702.06**			**767.95**	**$65.89**	**9.38%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption: 10,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			17.95			24.54	6.59	36.71%	1.63%
Distribution (kWh)	10,000	0.0147	147.00	10,000	0.0201	201.00	54.00	36.73%	13.37%
Low Voltage Rider (kWh)	10,000	0.0021	21.00	10,000	0.0035	35.00	14.00	66.67%	2.33%
Smart Meter Disposition Rider (per month)			1.00			2.51	1.51		0.17%
Stranded Smart Meter Rate Rider (per month)						1.37	1.37		
LRAM & SSM Rider (kWh)	10,000	0.0000	0.00	10,000	0.0000	0.00	0.00		0.00%
Late Payment ($)		0.4200	0.42	0	0.0000	0.00	(0.42)		0.00%
Deferrral & Variance Acct (kWh)	10,000	0.0000	0.00	10,000	0.0018	18.00	18.00		1.20%
Distribution Sub-Total			**187.37**			**282.42**	**95.05**	**50.73%**	**18.78%**
Retail Transmisssion (kWh)	10,543	0.0091	95.94	10,714	0.0089	95.35	(0.59)	(0.61%)	6.34%
Delivery Sub-Total			**283.31**			**377.77**	**94.46**	**33.34%**	**25.12%**
Other Charges (kWh)	10,543	0.0135	142.33	10,714	0.0133	142.50	0.17	0.12%	9.48%
Cost of Power Commodity (kWh)	10,543	0.0757	797.58	10,714	0.0757	810.51	12.94	1.62%	53.90%
Total Bill Before Taxes			**1,223.22**			**1,330.78**	**$107.57**	**8.79%**	**88.50%**
GST		13.00%	159.02		13.00%	173.00	13.98	8.79%	11.50%
Total Bill			**1,382.24**			**1,503.79**	**$121.55**	**8.79%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption: 12,500 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			17.95			24.54	6.59	36.71%	1.31%
Distribution (kWh)	12,500	0.0147	183.75	12,500	0.0201	251.25	67.50	36.73%	13.42%
Low Voltage Rider (kWh)	12,500	0.0021	26.25	12,500	0.0035	43.75	17.50	66.67%	2.34%
Smart Meter Disposition Rider (per month)			1.00			2.51	1.51	151.00%	0.13%
Stranded Smart Meter Rate Rider (per month)						1.37	1.37		
LRAM & SSM Rider (kWh)	12,500	0.0000	0.00	12,500	0.0000	0.00	0.00		0.00%
Late Payment ($)		0.4200	0.42	0	0.0000	0.00	(0.42)		0.00%
Deferrral & Variance Acct (kWh)	12,500	0.0000	0.00	12,500	0.0018	22.50	22.50		1.20%
Distribution Sub-Total			**229.37**			**345.92**	**116.55**	**50.81%**	**18.48%**
Retail Transmisssion (kWh)	13,179	0.0091	119.93	13,393	0.0089	119.19	(0.73)	(0.61%)	6.37%
Delivery Sub-Total			**349.30**			**465.11**	**115.82**	**33.16%**	**24.85%**
Other Charges (kWh)	13,179	0.0135	177.91	13,393	0.0133	178.12	0.21	0.12%	9.52%
Cost of Power Commodity (kWh)	13,179	0.0757	996.97	13,393	0.0757	1,013.14	16.17	1.62%	54.13%
Total Bill Before Taxes			**1,524.18**			**1,656.38**	**$132.19**	**8.67%**	**88.50%**
GST		13.00%	198.14		13.00%	215.33	17.19	8.67%	11.50%
Total Bill			**1,722.33**			**1,871.71**	**$149.38**	**8.67%**	**100.00%**

GENERAL SERVICE < 50 kW

Consumption: 15,000 kWh

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Monthly Service Charge			17.95			24.54	6.59	36.71%	1.10%
Distribution (kWh)	15,000	0.0147	220.50	15,000	0.0201	301.50	81.00	36.73%	13.46%
Low Voltage Rider (kWh)	15,000	0.0021	31.50	15,000	0.0035	52.50	21.00	66.67%	2.34%
Smart Meter Disposition Rider (per month)			1.00			2.51	1.51	151.00%	0.11%
Stranded Smart Meter Rate Rider (per month)						1.37	1.37		
LRAM & SSM Rider (kWh)	15,000	0.0000	0.00	15,000	0.0000	0.00	0.00		0.00%
Late Payment ($)		0.4200	0.42	0	0.0000	0.00	(0.42)		0.00%
Deferrral & Variance Acct (kWh)	15,000	0.0000	0.00	15,000	0.0018	27.00	27.00		1.21%
Distribution Sub-Total			**271.37**			**409.42**	**138.05**	**50.87%**	**18.28%**
Retail Transmisssion (kWh)	15,815	0.0091	143.91	16,071	0.0089	143.03	(0.88)	(0.61%)	6.39%
Delivery Sub-Total			**415.28**			**552.45**	**137.17**	**33.03%**	**24.67%**
Other Charges (kWh)	15,815	0.0135	213.50	16,071	0.0133	213.74	0.25	0.12%	9.54%
Cost of Power Commodity (kWh)	15,815	0.0757	1,196.37	16,071	0.0757	1,215.77	19.40	1.62%	54.28%
Total Bill Before Taxes			**1,825.14**			**1,981.97**	**$156.82**	**8.59%**	**88.50%**
GST		13.00%	237.27		13.00%	257.66	20.39	8.59%	11.50%
Total Bill			**2,062.41**			**2,239.62**	**$177.21**	**8.59%**	**100.00%**

GENERAL SERVICE > 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			161.36			190.93	29.57	18.33%	4.22%
30,000 kWh	Distribution (kW)	100	3.1566	315.66	100	3.6872	368.72	53.06	16.81%	8.15%
100 kW	Low Voltage Rider (kW)	100	0.8403	84.03	100	1.4840	148.40	64.37	76.60%	3.28%
	Smart Meter Disposition Rider (per month)			1.00			3.78	2.78	278.00%	0.08%
	Stranded Smart Meter Rate Rider (per month)						4.30	4.30		
	LRAM & SSM Rider (kW)	100		0.00	100	0.0000	0.00	0.00		0.00%
	Late Payment ($)		3.3000	3.30	0	0.0000	0.00	(3.30)		0.00%
	Deferrral & Variance Acct (kW)	100	0.0000	0.00	100	0.7582	75.82	75.82		1.68%
	Distribution Sub-Total			**565.35**			**791.95**	**226.60**	**40.08%**	**17.41%**
	Retail Transmisssion (kW)	100	4.6269	462.69	100	3.5224	352.24	(110.45)	(23.87%)	7.79%
	Delivery Sub-Total			**1,028.04**			**1,144.19**	**116.15**	**11.30%**	**25.29%**
	Other Charges (kWh)	31,629	0.0135	426.99	32,142	0.0133	427.49	0.50	0.12%	9.45%
	Cost of Power Commodity (kWh)	31,629	0.0757	2,392.73	32,142	0.0757	2,431.54	38.81	1.62%	53.75%
	Total Bill Before Taxes			**3,847.77**			**4,003.22**	**155.46**	**4.04%**	**88.50%**
	GST		13.00%	500.21		13.00%	520.42	20.21	4.04%	11.50%
	Total Bill			**4,347.97**			**4,523.64**	**175.66**	**4.04%**	**100.00%**

GENERAL SERVICE > 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			161.36			190.93	29.57	18.33%	1.74%
75,000 kWh	Distribution (kW)	250	3.1566	789.15	250	3.6872	921.80	132.65	16.81%	8.40%
250 kW	Low Voltage Rider (kW)	250	0.8403	210.08	250	1.4840	371.00	160.93	76.60%	3.38%
	Smart Meter Disposition Rider (per month)			1.00			3.78	2.78	278.00%	0.03%
	Stranded Smart Meter Rate Rider (per month)						4.30	4.30		
	LRAM & SSM Rider (kW)	250		0.00	250	0.0000	0.00	0.00		0.00%
	Late Payment ($)		3.3000	3.30	0	0.0000	0.00	(3.30)		0.00%
	Deferrral & Variance Acct (kW)	250	0.0000	0.00	250	0.7582	189.55	189.55		1.73%
3.3000	**Distribution Sub-Total**			**1,164.89**			**1,681.36**	**516.48**	**44.34%**	**15.29%**
	Retail Transmisssion (kW)	250	4.6269	1,156.73	250	3.5224	880.60	(276.13)	(23.87%)	8.03%
	Delivery Sub-Total			**2,321.61**			**2,561.96**	**240.35**	**10.35%**	**23.35%**
	Other Charges (kWh)	79,073	0.0135	1,067.48	80,355	0.0133	1,068.72	1.24	0.12%	9.74%
	Cost of Power Commodity (kWh)	79,073	0.0757	5,981.83	80,355	0.0757	6,078.86	97.02	1.62%	55.40%
	Total Bill Before Taxes			**9,370.92**			**9,709.54**	**338.61**	**3.61%**	**88.50%**
	GST		13.00%	1,218.22		13.00%	1,262.24	44.02	3.61%	11.50%
	Total Bill			**10,589.14**			**10,971.78**	**382.63**	**3.61%**	**100.00%**

GENERAL SERVICE > 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			161.36			190.93	29.57	18.33%	1.30%
100,000 kWh	Distribution (kW)	350	3.1566	1,104.81	350	3.6872	1,290.52	185.71	16.81%	8.76%
350 kW	Low Voltage Rider (kW)	350	0.8403	294.11	350	1.4840	519.40	225.30	76.60%	3.53%
	Smart Meter Disposition Rider (per month)			1.00			3.78	2.78	278.00%	0.03%
	Stranded Smart Meter Rate Rider (per month)						4.30	4.30		
	LRAM & SSM Rider (kW)	350		0.00	350	0.0000	0.00	0.00		0.00%
	Late Payment ($)		3.3000	3.30	0	0.0000	0.00	(3.30)		0.00%
	Deferrral & Variance Acct (kW)	350	0.0000	0.00	350	0.7582	265.37	265.37		1.80%
	Distribution Sub-Total			**1,564.58**			**2,274.30**	**709.73**	**45.36%**	**15.41%**
	Retail Transmisssion (kW)	350	4.6269	1,619.42	350	3.5224	1,232.84	(386.58)	(23.87%)	8.37%
	Delivery Sub-Total			**3,183.99**			**3,507.14**	**323.15**	**10.15%**	**23.81%**
	Other Charges (kWh)	105,430	0.0135	1,423.31	107,140	0.0133	1,424.96	1.66	0.12%	9.67%
	Cost of Power Commodity (kWh)	105,430	0.0757	7,975.78	107,140	0.0757	8,105.14	129.36	1.62%	55.02%
	Total Bill Before Taxes			**12,583.07**			**13,037.24**	**454.17**	**3.61%**	**88.50%**
	GST		13.00%	1,635.80		13.00%	1,694.84	59.04	3.61%	11.50%
	Total Bill			**14,218.87**			**14,732.08**	**513.21**	**3.61%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
800,000 kWh
2,000 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			161.36			190.93	29.57	18.33%	0.18%
Distribution (kW)	2,000	3.1566	6,313.20	2,000	3.6872	7,374.40	1,061.20	16.81%	6.84%
Low Voltage Rider (kW)	2,000	0.8403	1,680.60	2,000	1.4840	2,968.00	1,287.40	76.60%	2.75%
Smart Meter Disposition Rider (per month)			1.00			3.78	2.78	278.00%	0.00%
Stranded Smart Meter Rate Rider (per month)						4.30	4.30		
LRAM & SSM Rider (kW)	2,000		0.00	2,000	0.0000	0.00	0.00		0.00%
Late Payment ($)		3.3000	3.30	0	0.0000	0.00	(3.30)		0.00%
Deferrral & Variance Acct (kW)	2,000	0.0000	0.00	2,000	0.7582	1,516.40	1,516.40		1.41%
Distribution Sub-Total			**8,159.46**			**12,057.81**	**3,898.35**	**47.78%**	**11.19%**
Retail Transmisssion (kW)	2,000	4.6269	9,253.80	2,000	3.5224	7,044.80	(2,209.00)	(23.87%)	6.54%
Delivery Sub-Total			**17,413.26**			**19,102.61**	**1,689.35**	**9.70%**	**17.73%**
Other Charges (kWh)	843,440	0.0135	11,386.44	857,120	0.0133	11,399.70	13.26	0.12%	10.58%
Cost of Power Commodity (kWh)	843,440	0.0757	63,806.24	857,120	0.0757	64,841.13	1,034.89	1.62%	60.18%
Total Bill Before Taxes			**92,605.94**			**95,343.43**	**2,737.50**	**2.96%**	**88.50%**
GST		13.00%	12,038.77		13.00%	12,394.65	355.87	2.96%	11.50%
Total Bill			**104,644.71**			**107,738.08**	**3,093.37**	**2.96%**	**100.00%**

GENERAL SERVICE > 50 kW

Consumption
1,600,000 kWh
4,000 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge			161.36			190.93	29.57	18.33%	0.09%
Distribution (kW)	4,000	3.1566	12,626.40	4,000	3.6872	14,748.80	2,122.40	16.81%	6.85%
Low Voltage Rider (kW)	4,000	0.8403	3,361.20	4,000	1.4840	5,936.00	2,574.80	76.60%	2.76%
Smart Meter Disposition Rider (per month)			1.00			3.78	2.78	278.00%	0.00%
Stranded Smart Meter Rate Rider (per month)						4.30	4.30		
LRAM & SSM Rider (kW)			0.00	0	0.0000	0.00	0.00		0.00%
Late Payment ($)		3.3000	3.30	0	0.0000	0.00	(3.30)		0.00%
Deferrral & Variance Acct (kW)	4,000	0.0000	0.00	4,000	0.7582	3,032.80	3,032.80		1.41%
Distribution Sub-Total			**16,153.26**			**23,916.61**	**7,763.35**	**48.06%**	**11.11%**
Retail Transmisssion (kW)	4,000	4.6269	18,507.60	4,000	3.5224	14,089.60	(4,418.00)	(23.87%)	6.55%
Delivery Sub-Total			**34,660.86**			**38,006.21**	**3,345.35**	**9.65%**	**17.66%**
Other Charges (kWh)	1,686,880	0.0135	22,772.88	1,714,240	0.0133	22,799.39	26.51	0.12%	10.59%
Cost of Power Commodity (kWh)	1,686,880	0.0757	127,612.47	1,714,240	0.0757	129,682.26	2,069.78	1.62%	60.25%
Total Bill Before Taxes			**185,046.21**			**190,487.86**	**5,441.65**	**2.94%**	**88.50%**
GST		13.00%	24,056.01		13.00%	24,763.42	707.41	2.94%	11.50%
Total Bill			**209,102.22**			**215,251.28**	**6,149.06**	**2.94%**	**100.00%**

Street Lighting

Billing Determinants
1,100 Connections
52,000 kWh
140 kW

	2011 BILL			2012 BILL			IMPACT		
	Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Monthly Service Charge	1,100	1.4000	1,540.00	1,100	1.9307	2,123.77	583.77	37.91%	16.99%
Distribution (kW)	140	17.6963	2,477.48	140	24.4048	3,416.67	939.19	37.91%	27.34%
Low Voltage Rider (kW)	140	0.6403	89.64	140	1.0466	146.52	56.88	63.45%	1.17%
LRAM & SSM Rider (kW)			0.00	0	0.0000	0.00	0.00		0.00%
Late Payment ($)	1,100	0.0200	22.00	1,100	0.0000	0.00	(22.00)		0.00%
Deferrral & Variance Acct (kW)	140	0.0000	0.00	140	0.2977	41.68	41.68		0.33%
Distribution Sub-Total			**4,129.12**			**5,728.64**	**1,599.52**	**38.74%**	**45.84%**
Retail Transmisssion (kW)	140	2.7517	385.24	140	2.6835	375.69	(9.55)	(2.48%)	3.01%
Delivery Sub-Total			**4,514.36**			**6,104.33**	**1,589.97**	**35.22%**	**48.84%**
Other Charges (kWh)	54,824	0.0135	740.12	0.01330	55,713	740.98	0.86	0.12%	5.93%
Cost of Power Commodity (kWh)	54,824	0.0757	4,147.41	0.0757	55,713	4,214.67	67.27	1.62%	33.72%
Total Bill Before Taxes			**9,401.89**			**11,059.99**	**1,658.10**	**17.64%**	**88.50%**
GST		13.00%	1,222.25		13.00%	1,437.80	215.55	17.64%	11.50%
Total Bill			**10,624.13**			**12,497.79**	**1,873.65**	**17.64%**	**100.00%**

Sentinel Lighting

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Billing Determinants	Monthly Service Charge	1	1.2900	1.29	1.0	2.0852	2.09	0.80	61.64%	13.25%
1 Connections	Distribution (kW)	0.2	10.3652	2.07	0.2	16.7548	3.35	1.28	61.64%	21.29%
80 kWh	Low Voltage Rider (kW)	0.2	0.641	0.13	0.2	1.0684	0.21	0.09	66.68%	1.36%
0.20 kW	LRAM & SSM Rider (kW)			0.00	0.0	0.0000	0.00	0.00		0.00%
	Late Payment ($)	1.0	0.0300	0.03	1.0	0.0000	0.00	(0.03)		0.00%
	Deferral & Variance Acct (kW)	0.2	0.0000	0.00	0.2	0.5477	0.11	0.11		0.70%
	Distribution Sub-Total			**3.52**			**5.76**	**2.24**	**63.56%**	**36.60%**
	Retail Transmisssion (kW)	0.2	2.7832	0.56	0.2	2.7147	0.54	(0.01)	(2.46%)	3.45%
	Delivery Sub-Total			**4.08**			**6.30**	**2.22**	**54.55%**	**40.05%**
	Other Charges (kWh)	84	0.0135	1.14	86	0.0133	1.14	0.00	0.12%	7.24%
	Cost of Power Commodity (kWh)	84	0.0757	6.38	86	0.0757	6.48	0.10	1.62%	41.20%
	Total Bill Before Taxes			**11.60**			**13.93**	**2.33**	**20.08%**	**88.50%**
	GST		13.00%	1.51		13.00%	1.81	0.30	20.08%	11.50%
	Total Bill			**13.10**			**15.74**	**2.63**	**20.08%**	**100.00%**

Unmetered Scattered

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			8.82			11.94	3.12	35.38%	24.43%
250 kWh	Distribution (kWh)	250	0.0113	2.83	250	0.0153	3.83	1.00	35.40%	7.83%
	Low Voltage Rider (kWh)	250	0.0021	0.53	250	0.0035	0.88	0.35	66.67%	1.79%
	LRAM & SSM Rider (kWh)		0.0000	0.00		0.0000	0.00	0.00		0.00%
	Late Payment ($)	0	0.1400	0.14	0	0.0000	0.00	(0.14)		0.00%
	Deferral & Variance Acct (kWh)	250	0.0000	0.00	250	0.0016	0.40	0.40		0.82%
	Distribution Sub-Total			**12.31**			**17.04**	**4.73**	**38.43%**	**34.87%**
	Retail Transmisssion (kWh)	264	0.0091	2.40	268	0.0089	2.38	(0.01)	(0.61%)	4.88%
	Delivery Sub-Total			**14.71**			**19.42**	**4.72**	**32.06%**	**39.75%**
	Other Charges (kWh)	264	0.0135	3.56	268	0.0133	3.56	0.00	0.12%	7.29%
	Cost of Power Commodity (kWh)	264	0.0757	19.94	268	0.0757	20.26	0.32	1.62%	41.46%
	Total Bill Before Taxes			**38.21**			**43.25**	**5.06**	**13.24%**	**88.50%**
	GST		13.00%	4.97		13.00%	5.62	0.66	13.20%	11.50%
	Total Bill			**43.17**			**48.87**	**5.71**	**13.23%**	**100.00%**

Unmetered Scattered

		2010 BILL			2011 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	Change $	Change %	% of Total Bill
Consumption	Monthly Service Charge			8.82			11.94	3.12	35.38%	14.17%
500 kWh	Distribution (kWh)	500	0.0113	5.65	500	0.0153	7.65	2.00	35.40%	9.08%
	Low Voltage Rider (kWh)	500	0.0021	1.05	500	0.0035	1.75	0.70	66.67%	2.08%
	LRAM & SSM Rider (kWh)		0.0000	0.00		0.0000	0.00	0.00		0.00%
	Late Payment ($)	0	0.1400	0.14	0	0.0000	0.00	(0.14)		0.00%
	Deferral & Variance Acct (kWh)	500	0.0000	0.00	500	0.0016	0.80	0.80		0.95%
	Distribution Sub-Total			**15.66**			**22.14**	**6.48**	**41.38%**	**26.28%**
	Retail Transmisssion (kWh)	527	0.0091	4.80	536	0.0089	4.77	(0.03)	(0.61%)	5.66%
	Delivery Sub-Total			**20.46**			**26.91**	**6.45**	**31.54%**	**31.94%**
	Other Charges (kWh)	527	0.0135	7.12	536	0.0133	7.12	0.01	0.12%	8.46%
	Cost of Power Commodity (kWh)	527	0.0757	39.88	536	0.0757	40.53	0.65	1.62%	48.10%
	Total Bill Before Taxes			**67.45**			**74.56**	**7.14**	**10.58%**	**88.50%**
	GST		13.00%	8.77		13.00%	9.69	0.92	10.54%	11.50%
	Total Bill			**76.22**			**84.25**	**8.06**	**10.57%**	**100.00%**

Exhibit 9 - Deferral and Variance Accounts

ERHDC has revised the smart meter disposition rate rider as per question #35.

Model to be submitted with the Interrogatory Responses

ERHDC has submitted the following excel model that reflect the above noted changes as a result of the interrogatory responses.

- Revenue requirement workform
- RTSR workform
- Cost Allocation model
- Smart meter disposition model
- PILs workform

Question # 37

Deferral and Variance Accounts

Ref: Exhibit 9/ Tab 1/ Schedule 2/ Page 6; Exhibit 9/ Tab 1/ Schedule 3/ Page 8; Exhibit 9/ Tab 1/ Schedule 3/ Page 8; Chapter 2 of the Filing Requirements for Transmission and Distribution Applications June 22, 2011, Page 48

ERHDC is requesting to dispose of Account 1592, PILs & Tax Variance for 2006 & Subsequent Years, Sub-account HST/OVAT Input Tax Credits (ITCs) in the amount of $7,888 (credit), 50% of the $15,777 credit balance in Account 1592.

Chapter 2 of the Filing Requirements for Transmission and Distribution Applications states:

No more amounts should be recorded in Account 1592 (PILs and Tax Variances, Sub-account HST/OVAT ITCs for the Test Year and going forward, as the impact of the HST and associated ITCs on capital and operating costs in the Test Year should be reflected in the applied for revenue requirement.

Please confirm that ERHDC does not intend to continue to use the sub-account of Account 1592 for the Test Year and going forward. If this is not the case, please explain.

ERHDC Response

ERHDC confirms that is does not intend to use the above noted sub-account of 1592 for the test year and going forward.

<u>Question # 38</u>

Modified International Financial Reporting Standards

Ref: Exhibit 1/ Tab 3/ Schedule 1, Appendix D, Page 25, 31; Exhibit 1/ Tab 3/ Schedule 3, Appendix E, Page 5; Exhibit 1/ Tab 3/ Schedule 3, Appendix F, Page 5

ERHDC had an Employee Future Benefits Obligation of $65,287 as per the Note 8 of the 2010 Financial Statements.

a) Please confirm if ERHDC has unamortized actuarial gains and losses, and past service costs at the date of transition (January 1, 2011).
b) If the answer to part a) above is "yes", what is the accounting treatment of the unamortized actuarial gains and losses, and past service costs at the date of transition?
c) What is the proposed regulatory treatment of these amounts – are these amounts incorporated anywhere in the revenue requirement? Please explain.
d) Board staff notes that in the 2010 Financial Statements, ERHDC had an Employee Future Benefit Obligation of $65,287. In the 2011 and 2012 Pro-forma statements, Employee Future Benefits under Non-Current Liabilities had a $0 balance. Please reconcile the 2010 Employee Future Benefit Obligations balance to the 2011 and 2012 Employee Future Benefit Obligations balance.

<u>ERHDC Response</u>

a) ERHDC has no unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011).

b) Not applicable

c) Not applicable

d) ERHDC did not include an amount for employee future benefit obligations in the 2011 Bridge year and 2012 Test year due to the immateriality and uncertainty of the amount to recognized as income. Refer to the table below for the historical employee future benefit obligation balance

2008	2009	2008 vs. 2009	2010	2009 vs 2010	2011	2010 vs 2011
65,495	57,400	**(8,095)**	65,287	**7,887**	61,542	**(3,745)**

Question # 39

Ref: Exhibit 4/ Tab 2/ Schedule 5/ Page 13; Accounting Procedure Handbook (“APH”), Frequently Asked Question (“FAQ”), October 2009, A.1

In reference to APH, FAQ, October 2009, A.1,

> The Board has approved a deferral account for a distributor to record onetime administrative incremental IFRS transition costs, which are not already approved and included for recovery in distribution rates. In such circumstances, the incremental costs…will be recorded in a new and separate sub-account of account 1508, Other Regulatory Accounts, “Subaccount Deferred IFRS Transition Costs”, in the Uniform System of Accounts.

ERHDC indicated that ERHDC will require assistance from consultants for the transition from CGAAP to IFRS and the estimated costs is approximately $50,000 over a 4 year period. Board Staff notes that ERHDC has included $12,500 of IFRS costs in 2012 O&MA as per Table 4-12, OM&A Cost Drivers.

a) Please clarify if ERHDC has incurred any administrative incremental IFRS transition costs to date,
b) If the answer to part a) above is “yes”, please disclose the activities undertaken and the amount incurred to date. Please also explain why these costs have not been included in Account 1508 as per APH, FAQ, October 2009.
c) If the answer to part a) above is “no”, please indicate when ERHDC expects to implement IFRS.

d) Please explain why the $12,500 of estimated costs for 2012 is included in O&M to be reflected in rates instead of using the deferral account as stated in the above to record the IFRS costs.

ERHDC Response

a) ERHDC has not incurred an administrative incremental IFRS transition costs to date.

b) Not applicable

c) ERHDC expects to implement IFRS January 1, 2013.

d) It is ERHDC's understanding that the deferral account is to be used for costs which are not included in the distributors rates. Therefore in an IRM year the deferral account should be used until rebased. Since ERHDC is in a cost of service year it would be appropriate to include the costs in the revenue requirement and distribution rates amortized over 4 years.

Question # 40

Ref: Exhibit 6/ Tab 2/ Schedule 2/ Page 1, Table 6-4; Exhibit 2/ Tab 2/ Schedule 4/ Page 11, Table 2-14; Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012

a) The Board issued the Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective May 1, 2012 on March 2, 2012. Please update the rate of return in Exhibit 6, Tab 2, Schedule 2, Table 6-4 based on the Letter of the Board.

b) In Exhibit 6/ Tab 2/ Schedule 2/ Page 1, ERHDC stated:

> ERHDC has made an adjustment to depreciation expense included in the service revenue requirement. Refer to Exhibit 2, Tab 2, Schedule 5, Table 2-11 for adjustment to depreciation expense.

However, Board staff notes that Exhibit 2/ Tab 2/ Schedule 4/ Page 11, Table 214 shows the PP&E deferral adjustment to depreciation. Please confirm that the adjustment to depreciation expense is reflected in Exhibit 2, Tab 2, Schedule 4, Page 11, Table 2-14 and not in Exhibit 2/ Tab 2/ Schedule 5/ Table 2-11.

ERHDC Response

a)

IFRS 2011 NBV	2,494,557
CGAAP 2011 NBV	2,400,062
Difference	94,495
Amortized over 4 years	23,624
Add: Rate of Return 9.12%	8,618
Adjustment to Depreciation Expense	32,242

b) ERHDC confirms that the adjustment to depreciation expense is reflected in Exhibit 2, Tab 2/ Schedule 4/ page 11/ Table 2-14.

<u>Question # 41</u>

Ref: Additional Information filed March 7, 2012, Page 5, Item #5

Per Additional Information, page 5, ERHDC indicated that:

> ERHDC has not accounted for any gains or losses on the retirements of assets in the cost of service rate application.

a) Please confirm if ERHDC has any gains or losses on the retirement of assets.
b) If answer to part (a) above is "yes", please describe the nature of the gains or losses and the reason why the gains or losses have not been accounted for in the application.

<u>ERHDC Response</u>

a) ERHDC confirms there are no gains or losses on the retirement of assets.

b) Not applicable.

Question # 42

Ref: Additional Information filed March 7, 2012, Page 5, Item #6

Per Additional Information, page 5, ERHDC indicated that:

> ERHDC has not recorded any asset impairment losses in the cost of service application.

a) Please confirm if ERHDC has any asset impairment losses.
b) If answer to part (a) above is "yes", please describe the nature of the asset impairment losses and the reason why the losses have not been accounted for in the application.

ERHDC Response

a) ERHDC confirms there are no asset impairment losses.

b) Not applicable.