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Ontario

BY E-MAIL

May 11, 2012

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

Dear Ms. Walli:

Re: Espanola Regional Hydro Distribution Corporation
2012 Distribution Rate Application
Board Staff Interrogatories
Board File No. EB-2011-0319

In accordance with Procedural Order No. 1, please find attached Board Staff Interrogatories in the above proceeding.

Yours truly,

Original Signed By

Silvan Cheung
Advisor – Applications & Regulatory Audit

Encl.

Board Staff Interrogatories
2012 Electricity Distribution Rates
Espanola Regional Hydro Distribution Corporation ("ERHDC")
EB-2011-0319
May 11, 2012

Administration

1. Ref: Responses to Letter of Comment

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.

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.

Capital Expenditures

3. 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.

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 <u>service quality</u> indicators and provide an explanation for the indicators that were under performing and the actions taken to address the under performance.

Load and Customer Forecasting

5. 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.

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.

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.

Other Revenues

8. 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.

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

9. 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.

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.

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.

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.

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.

Green Energy Plan

14. 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:
    - equipment type; and
    - by location 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.

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-2009-0397], 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
Undergruond 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	62 640	62 640	62 640	62 640	62 640	62 640	62 640	62 640	62 640	62 640	626 400
Disconnect Switches, Cutotus	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	1 232 360	1 232 360	707 360	707 360	707 360	707 360	332 360	332 360	707 360	707 360	7 373 600

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						

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-2009-0397], 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.

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 of100)	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”

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-2009-0397], 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.

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.

Cost of Capital and Rate of Return

20. 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:

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.

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:

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.

Cost Allocation

21. 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.

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.

Rate Design

23. 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.

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.

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.

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.

LRAM

27. 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.

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.

Smart Meters

29. 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.

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.

31. 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 sub-account 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.

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.

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

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
- Consumer Education Plan.

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.

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.

Miscellaneous

36. 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.

Deferral and Variance Accounts

37. 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.

Modified International Financial Reporting Standards

38. 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.

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 one-time 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, "Sub-account 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.

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 2-14 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.

41. 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 loses and the reason why the gains or losses have not been accounted for in the application.

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.