EB-2011-0271

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Halton Hills Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2012.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")
CROSS-EXAMINATION COMPENDIUM

NORTON ROSE

Barristers & Solicitors / Patent & Trade-mark Agents

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On January 1, 2012, Macleod Dixon joined
Norton Rose OR to create Norton Rose Canada.

March 12, 2012

Filed on RESS and Sent by Courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700
2300 Yong Street
Toronto ON M4P 1E4

Your reference
EB-2011-0271

Direct line
+1 (416) 216-1927

Our reference
01005480-0015

Email
john.beauchamp@nortonrose.com

Dear Ms. Walli:

Halton Hills Hydro Inc.
Distribution Rates 2012 (EB-2011-0271)

We are counsel to Halton Hills Hydro Inc. ("HHH") in the above-captioned matter.

In accordance with Procedural Order No. 4, please find enclosed HHH's updated evidence with respect to HHH's PP&E Account (as referenced in section 11.1 of the Partial Settlement Agreement filed with the Board on February 29, 2012).

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,

"Signed"

John Beauchamp

JB/mnm

Enclosure

Cop(y/ies) to: All Intervenors in EB-2011-0271
Art Skidmore (HHH)
David Smelsky (HHH)

DOCSTOR: 2376007\1

HALTON HILLS HYDRO INC.
2012 Distribution Rates
PP&E Deferral Account

As noted in section 11 of the Settlement Agreement filed with the Board on February 29, 2012, HHH is filing updated evidence with respect to HHH's PP&E Deferral Account, which tracks the amounts attributable to the difference between CGAAP and IFRS calculations of net fixed assets as at the end of 2011.

HHH is proposing to amortize its PP&E Deferral Account over a period of twenty (20) years. In HHH's view, this amortization period closely matches the average remaining useful life of the underlying assets. HHH also proposes to calculate the return on rate base on a modified declining balance, adjusted every four years to coincide with each rate rebasing period. This approach will result in an annual reduction in the revenue requirement in the amount of:

- $161,569 in Years 1 through 4;
- $143,430 in Years 5 through 8;
- $125,291 in Years 9 through 12;
- $107,152 in Years 13 through 16; and
- $89,013 in Years 17 through 20.

The resulting Net Present Value ("NPV") cash flow impact is ($1,510,158).

IFRS is an evolving set of accounting standards. In the area of regulatory deferral and variance accounts, HHH is of the view that the regulatory accounting and reporting requirements established by the Board should first and foremost be based on sound principles of rate regulation – including fairness to customers and the utility, minimizing intergenerational inequities in rate-setting, and minimizing rate volatility.

The Board has provided policy guidance on the transition to IFRS in *Report of the Board, Transition to IFRS* dated July 28, 2009 ("Report"). On July 11, 2011, the Board also released an Addendum *to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment* (the "Addendum"). The Addendum sets out additional regulatory policy regarding the transition to IFRS in the circumstances where utilities rates are rebased using cost of service rate-setting methods and where rates are subsequently set for a period of years using an IRM. In Appendix A of the Addendum (under Issue 2), the Board authorizes the creation of a generic IFRS transition PP&E Deferral Account to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS, and provides policy guidance with respect to said deferral accounts

The proposed PP&E Deferral Account is intended to cover differences arising only as a result of the accounting policy changes caused by the transition from CGAPP to MIFRS. The amount of the cumulative adjustment up or down (unamortized balance of the deferral account) will be recorded as a balance to be recovered from or refunded to, ratepayers and as an adjustment to rate base in the year of rebasing (with rate base calculated on a MIFRS basis).

The Board requires the utility to reflect an adjustment to MIFRS calculated rate base going forward and <u>amortize that adjustment over a period of time</u> approved by the Board.

As per Appendix A to the Addendum, the Board will determine the period of time for amortization <u>on a case-by-case basis</u> and will be guided primarily by such considerations as the:

- impact on rates;
- implications of any other IFRS transition matters; and
- any requirements for rate mitigation.

The rate impact to HHHI is a cumulative adjustment down to rate base to be refunded to ratepayers in the amount of $1,462,823. Amortizing over a short period (e.g., four years, as some utilities have done based on a sample in a Board Staff submission of March 31, 2011 (Appendix A)), would result in an annual reduction in the revenue requirement of $456,401. This is a significant revenue requirement reduction and would cause significant cash flow impacts to HHH. The Net Present Value (NPV) cash flow impact is ($1,574,261).

Further, amortizing over a shorter period would not correspond to the remaining useful lives of the assets underpinning the Account. Consequently, an amortization period of 20 years is more appropriate from a regulatory perspective. It is fair to HHH in terms of not imposing undue cash flow impacts on the utility, and it is more appropriate from an intergenerational equity perspective and rate volatility perspective.

Halton Hills Hydro Inc.
PP& E Deferral Account
Proposal

Option

1 **NPV of HHHI's 20 year amortization - Adjusted every four years to coincide with rate rebasing**

Net Present Value: **($1,510,158)**

	Accum Total	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Opening		1,462,823	1,389,682	1,316,541	1,243,400	1,170,258	1,097,117	1,023,976	950,835	877,694	804,553	731,412	658,270	585,129	511,988	438,847	365,706	292,565	219,423	146,282	73,141
Amortization		73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141
Closing		1,389,682	1,316,541	1,243,400	1,170,258	1,097,117	1,023,976	950,835	877,694	804,553	731,412	658,270	585,129	511,988	438,847	365,706	292,565	219,423	146,282	73,141	0
Average		1,426,252	1,353,111	1,279,970	1,206,829	1,133,688	1,060,547	987,406	914,264	841,123	767,982	694,841	621,700	548,559	475,417	402,276	329,135	255,994	182,853	109,712	36,571
Return	1,042,993	88,428	88,428	88,428	88,428	70,289	70,289	70,289	70,289	52,150	52,150	52,150	52,150	34,011	34,011	34,011	34,011	15,872	15,872	15,872	15,872
Amortization	1,462,823	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141
Total	2,505,816	161,569	161,569	161,569	161,569	143,430	143,430	143,430	143,430	125,291	125,291	125,291	125,291	107,152	107,152	107,152	107,152	89,013	89,013	89,013	89,013

2 **NPV of HHHI's 20 year amortization - Declining Balance Approach**

Net Present Value: **($1,437,233)**

	Accum Total	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Opening		1,462,823	1,389,682	1,316,541	1,243,400	1,170,258	1,097,117	1,023,976	950,835	877,694	804,553	731,412	658,270	585,129	511,988	438,847	365,706	292,565	219,423	146,282	73,141
Amortization		73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141
Closing		1,389,682	1,316,541	1,243,400	1,170,258	1,097,117	1,023,976	950,835	877,694	804,553	731,412	658,270	585,129	511,988	438,847	365,706	292,565	219,423	146,282	73,141	0
Average		1,426,252	1,353,111	1,279,970	1,206,829	1,133,688	1,060,547	987,406	914,264	841,123	767,982	694,841	621,700	548,559	475,417	402,276	329,135	255,994	182,853	109,712	36,571
Return	906,950	88,428	83,893	79,358	74,823	70,289	65,754	61,219	56,684	52,150	47,615	43,080	38,545	34,011	29,476	24,941	20,406	15,872	11,337	6,802	2,267
Amortization	1,462,823	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141	73,141
Total	2,369,773	161,569	157,034	152,499	147,965	143,430	138,895	134,360	129,826	125,291	120,756	116,221	111,687	107,152	102,617	98,082	93,548	89,013	84,478	79,943	75,409

3 **NPV of OEB Approach**

Net Present Value: **($1,574,261)**

	Accum Total	2012	2013	2014	2015
Opening		1,462,823	1,097,117	731,412	365,706
Amortization		365,706	365,706	365,706	365,706
Closing		1,097,117	731,412	365,706	-
Return	362,780	90,695	90,695	90,695	90,695
Amortization	1,462,823	365,706	365,706	365,706	365,706
Total	1,825,603	456,401	456,401	456,401	456,401

Ontario Energy Board

EB-2008-0408

Addendum to Report of the Board:

Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment

June 13, 2011

Appendix A: Summary of Board Policy in this Addendum

Issue 1

Information supporting rate adjustments during an IRM period should be provided in the same basis of accounting as the information upon which the rates were set. This means that if rates were set on CGAAP, the financial information supporting the adjustment must be provided under CGAAP, and the adjustment to rates will be made on the basis of the CGAAP filing.

In addition, a reconciliation of the CGAAP-based financial information mentioned above to the relevant information in the last annual RRR reporting under modified IFRS is required. Where the distributor has adopted IFRS for financial reporting but has not yet made an annual RRR reporting under modified IFRS, the financial information mentioned above must be provided in both CGAAP and modified IFRS format, and a reconciliation provided between the two accounting standards.

No third party assurance is required for the reconciliations, although an applicant can choose to file such assurance as part of its evidence supporting the reconciliation.

Issue 2

The Board authorizes the creation of a generic IFRS transition PP&E deferral account to record differences arising as a result of accounting policy changes caused by the transition from CGAAP to MIFRS as follows (for purposes of this account, PP&E includes rate base related intangible assets.):

1. Utilities shall maintain records using CGAAP of the amounts in the PP&E accounts that will be included in rate base, commencing at their last rebasing under CGAAP, and continuing until their first rebasing under MIFRS. This will produce a figure for the PP&E accounts that is consistent with their last rebasing. Records should be kept to at a level of detail sufficient to support the analysis and justification of the entries made to the account.
2. Utilities shall also calculate "adjusted rate base" values for the PP&E components of rate base using the accounting system applicable in each year

between rebasing under CGAAP and the first rebasing under MIFRS. For example, if a utility rebased using CGAAP in 2010, and continued with CGAAP in 2011, and then moved to IFRS for financial reporting for 2012 and 2013, it would calculate the PP&E components of rate base using CGAAP in 2010 and 2011, and MIFRS in 2011, 2012 and 2013. (2011 must be included in MIFRS because the year before the move to IFRS has to be restated under IFRS.)

3. Utilities shall record in the deferral account the cumulative difference between items 1 and 2 above. The calculations for the balance in this account (which does not accrue carrying charges), will provide the Board with the evidence to consider an adjustment to the opening values of the PP&E components of rate base up or down in the first MIFRS rebasing year to match the “adjusted rate base” figure above. For that rebasing year, and every subsequent year, rate base will be calculated on a MIFRS basis.

4. The amount of the cumulative adjustment up or down (unamortized balance of the deferral account) should be recorded as a balance to be recovered from, or refunded to, ratepayers and as an adjustment to opening rate base in the year of rebasing (with rate base otherwise calculated on an MIFRS basis).

5. Utilities shall reflect the deferral account balance as an adjustment to MIFRS calculated rate base going forward, and amortize that adjustment over a period of time approved by the Board. The rate base, upon which the utility return on rate base calculation is based in the cost of service application, will therefore include two components: the MIFRS based elements of PP&E; and, the unamortized balance in the deferral account. Thus the unamortized balance in the deferral account will attract the same level of return in determining revenue requirement in a cost of service application as other PP&E balances.

The Board will determine the period of time for amortization on a case-by-case basis and will be guided primarily by such considerations as the impact on rates, implications of any other IFRS transition matters and any requirements for rate mitigation.

Amortization of the adjusting amount, up or down, shall be reflected in any applicable rate application as an adjustment to depreciation expense (the refund or recovery of the amount of the adjustment over time) and the return on rate base calculation on the unamortized balance shall be included in applicable revenue requirement calculations in the same way as for any other component of rate base.

Utilities must propose the level and pattern of recovery in rates of the amounts in the account for consideration by the Board in their next cost of service application after adopting IFRS. In general, the account will be cleared at the first rebasing under MIFRS. In individual cases, the Board may decide to clear only a portion of the balance, and await actual results for the clearance of the remainder of the account.

The Board will not approve the creation of a generic account for IFRS related impacts on P&OPEB accounts occurring at the date of transition. The option remains for utilities to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

Issue 3:

The Board will not create or define a specific account for IFRS impacts on taxes or PILs. Board staff and industry participants should monitor developments in this area and notify the Board should a specific need for additional guidance from the Board emerge.

Issue 4:

The Board requires a utility that adopts USGAAP or an alternate accounting standard other than IFRS, in its first cost of service application following the adoption of the new accounting standard, to:

- demonstrate the eligibility of the utility under the relevant securities legislation to report financial information using that standard;
- include a copy of the authorization to use the standard from the appropriate Canadian securities regulator (if applicable); and
- set out the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

If a utility is required to transition to IFRS for financial reporting purposes a few years after adopting USGAAP, the Board will carefully scrutinize the costs incurred to

Table 9-7: 2012 Deferral and Variance Account Disposition Amounts

Account Description	Account Number	Total Claim
LV Variance Account	1550	$ (626,808)
RSVA - Wholesale Market Service Charge	1580	$ (633,794)
RSVA - Retail Transmission Network Charge	1584	$ 362,845
RSVA - Retail Transmission Connection Charge	1586	$ 330,907
RSVA - Power (excluding Global Adjustment)	1588	$ (913,830)
RSVA - Power - Sub-Account - Global Adjustment	1588	$ 2,303,654
Recovery of Regulatory Asset Balances	1590	$ 67,673
Other Regulatory Assets - Sub-Account - Incremental Capital Charges	1508	$ 75,275
Other Regulatory Assets - Sub-Account - Other	1508	$ 182,885
Retail Cost Variance Account - Retail	1518	$ (31,418)
Misc. Deferred Debits	1525	$ 8,184
Retail Cost Variance Account - STR	1548	$ 2,388
Deferred Payments in Lieu of Taxes	1562	$ (500,022)
Total		**$ 627,940**

Halton Hillis Hydro Inc.
, License Number , File Number

Debt & Capital Cost Structure

Weighted Debt Cost

Description	Debt Holder	Affliated with LDC?	Date of Issuance	Principal	Term (Years)	Rate%	Year Applied to	Interest Cost
Note Payable	Town of Halton Hills	Y		16,141,970		6.25%	2008	1,008,873
							2008	0
Note Payable	Town of Halton Hills	Y		16,141,970		6.25%	2009	1,008,873
							2009	0
Note Payable	Town of Halton Hills	Y		16,141,970		6.25%	2010	1,008,873
							2010	0
Note Payable	Town of Halton Hills	Y		16,141,970		6.25%	2011	1,008,873
							2011	0
Note Payable	Town of Halton Hills	Y		16,141,970		5.01%	2012	808,713
							2012	0

2008 Total Long Term Debt	16,141,970	**Total Interest Cost for 2008**	1,008,873
		Weighted Debt Cost Rate for 2008	6.25%
2009 Total Long Term Debt	16,141,970	**Total Interest Cost for 2009**	1,008,873
		Weighted Debt Cost Rate for 2009	6.25%
2010 Total Long Term Debt	16,141,970	**Total Interest Cost for 2010**	1,008,873
		Weighted Debt Cost Rate for 2010	6.25%
2011 Total Long Term Debt	16,141,970	**Total Interest Cost for 2011**	1,008,873
		Weighted Debt Cost Rate for 2011	6.25%
2012 Total Long Term Debt	16,141,970	**Total Interest Cost for 2011**	808,713
		Weighted Debt Cost Rate for 2011	5.01%

Deemed Capital Structure for 2012

Description	$	% of Rate Base	Rate of Return	Return
Long Term Debt	24,116,372	56.00%	5.01%	1,208,230
Unfunded Short Term Debt	1,722,598	4.00%	2.08%	35,830
Total Debt	25,838,970	60.00%		1,244,060
Common Share Equity	17,225,980	40.00%	9.42%	1,622,687
Total equity	17,225,980	40.00%		1,622,687
Total Rate Base	43,064,950	100.00%	6.66%	2,866,748

11. [Ex. 4./2/p.5]
With respect to the new Apprentice Meter Technician, when specifically does the current meter technician plan to retire?

Response:

The Meter Technician is expected to retire in 2016. And with the apprentice program being four years the appropriate time for succession planning is 2012.

12. [Ex. 4/B]
Please explain how the Applicant priced each of its services contained in the Appendixes of the Service Agreements between itself and its affiliates.

Response:

Based on time and materials and subject to annual review.

13. [Ex. 5/1/3/p/1]
Please provide a copy of all outstanding debt instruments held by the Applicant.

Response:

(i) Please refer to HHHI interrogatory response to OEB Board Staff question 35 part a, for the Long Term Note Payable to the Town of Halton Hills;

(ii) Please refer to Appendix SEC 1-C, attached, for Smart Meter Term Loan – TD Commercial Banking.

14. [Ex. 5/1/3/p/1]
Did the Applicant consider approaching Infrastructure Ontario as a way to finance its long-term capital spending? If not, please explain why.

Response:

Yes, HHHI approached Infrastructure Ontario.

APPENDIX SEC 1-C

TD Commercial Banking

Central Ontario Commercial Banking Group
89 Broadway Street
Orangeville. ON
L9W 1K2

Telephone No.: 519-941-1850 ext 280
Fax No.: (519) 941-9061

December 23, 2009

Halton Hills Hydro Inc.
43 Alice St
Acton,ON
L7J 2A9

Attention: Art Skidmore

We are pleased to offer the Borrower the following credit facilities (the "Facilities"), subject to the following terms and conditions.

BORROWER	Halton Hills Hydro Inc. (the "Borrower")
LENDER	**The Toronto-Dominion Bank** (the "Bank"), through its Central Ontario Commercial Banking Centre branch in Orangeville, Ontario.
CREDIT LIMIT	1) CDN$ 3,500,000 2) CDN $4,000,000 3) CDN $4,000,000 as reduced pursuant to the section headed "Repayment and Reduction of Amount of Credit Facility".
TYPE OF CREDIT AND BORROWING OPTIONS	1) **Operating Loan** available at the Borrower's option by way of: • Prime Rate Based Loans in CDN$ ("Prime Based Loans") • Bankers Acceptances in CDN$ or US$ ("B/As") • Letters of Credit in CDN$ or US$ ("L/Cs") • Stand-by Letters of Guarantee in CDN$ ("L/Gs") 2) **Interim Demand Loan** available at the Borrower's option by way of: • Prime Rate Based Loans in CDN$ ("Prime Based Loans") • Bankers Acceptances in CDN$ or US$ ("B/As")

3) **Committed Term Facility (Single Draw)** available at the Borrower's option by way of:
- Floating Rate Term Loan(s) available by way of:
  - Prime Rate Based Loans in CDN$ ("Prime Based Loans")
  - Bankers Acceptances in CDN$ or US$ ("B/As")

PURPOSE

1) To finance working capital requirements including IESO Prudential requirements
2) To finance smart meter implementation (hardware and installation).
3) To takeout Facility #2.

TENOR

1,2,) Uncommitted
3) Committed

CONTRACTUAL TERM

1,2) No term
3) 1 year

AMORTIZATION

3) Maximum 15 years

INTEREST RATES AND FEES

Advances shall bear interest and fees as follows:

1) **Operating Loan:**
- Prime Based Loans: Prime Rate + 0.00% per annum
- B/As: Stamping Fee at 1.00% per annum
- L/Cs: As advised by the Bank at the time of issuance of the L/C
- L/Gs: .050% per annum

2) **Interim Demand Loan:**
- Prime Based Loans: Prime Rate + 0.00% per annum
- B/As: Stamping Fee at 1.25% per annum

3) **Committed Term Facility:**
- Floating Rate Term Loans available by way of:
  - Prime Based Loans: Prime Rate + 0.00% per annum
  - B/As: Stamping Fee at 1.40% per annum

For all Facilities, interest payments will be made in accordance with Schedule "A" attached hereto unless otherwise stated in this Letter or in the Rate and Payment Terms Notice applicable for a particular drawdown. Information on interest rate and fee definitions, interest rate calculations and payment is set out in the Schedule "A" attached hereto.

Interrogatory # 62
Reference: SEC Interrogatory #13 & #14

a) Please provide the forecasted amount(s) expected to be borrowed by HHHI in 2012 from the TD Commercial Bank loan and indicate the expected interest rate to be charged for 2012.

b) Please provide more details on discussions that took place with Infrastructure Ontario and the rates that were available at the time of the discussions.

c) What are the current rates available from Infrastructure Ontario for terms of 5, 10, 15, 25 and 50 year terms?

a) New construction financing required for the 2012 capital budget is approximately $5,000,000. Depending on the amortization period and term of the loan, expected interest rates will range from 3.20% to 4.08%. For example, a 15 year amortization, 5 year term loan – interest rate is 3.20%.

b) Please see HHHI response to SEC Interrogatory question #27.

c) Infrastructure Ontario Lending Rates for Local Distribution Companies are updated frequently with the movement of the cost borrowing in the capital markets. Current lending rates are available on Infrastructure Ontario's website:

http://infrastructureontario.org/en/loan/rates/sectors/local_distribution_rates.asp

Interrogatory # 63
Reference: VECC Interrogatory #5 &
Exhibit 2, Tab 2, Schedule 3

The response to both parts (b) and (c) of the interrogatory refer to Appendix VECC 1-A.

However, there is only one set of projects shown for each year in that appendix.

a) Please confirm that the tables provided in the appendix reflect the proposed projects in each year.

b) Please confirm that the comparable list of projects and associated costs on an actual basis for these years are Table 2-14 (2008), Table 2-15 (2009), Table 2-16 (2010) and Table 2-17 (2011) in Exhibit 2, Tab 2, Schedule 3. If this cannot be confirmed, please provide a table for each of 2008 through 2011 that is a

26.
Reference: SEC#12

With respect to the Service Agreements with the Applicant and its affiliates, please explain and provide details on how the time and materials are valued.

A valuation of time and materials (cost plus mark-up) is determined during the annual budget setting process and includes a complete review of:

- Administrative support services
- Occupancy costs
- Meter Reading (water), postage and billing supplies
- Hourly rates including burdens and equipment

27.
Reference: SEC#14

Why did the Applicant not finance its long-term capital through Infrastructure Ontario?

HHHI has approached Infrastructure Ontario as an alternative resource to finance capital construction projects in the past and will continue to do so in the future. HHHI's financial institution provided a lower rate and more flexible terms than Infrastructure Ontario.

28.
Reference: Board Staff#23

Please explain the large decrease in Maintenance expenses from 2008 to 2009.

Please refer to Exhibit 4, Tab 2, Schedule 3, pages 2 & 3 of the Application.

a) The YTD actual for November 2010, shown in Table EP 2-7, were based on internal Financial Statements and were preliminary numbers that were not yet adjusted as a result of the 2010 Year End Audit.

b) No.

Question #6

Ref: Energy Probe IR #62

a) Does Halton Hills currently have a loan from the TD Commercial Bank, or any other third party lender?

b) If so, what is the amount, interest rate and term of the loan?

c) If not, when does Halton Hills expect to enter into a loan agreement with the third party, and what term of the loan will Halton Hills be seeking?

a) Yes.

b) The amount is at December 31, 2011 $3,943,430 and an interest rate of 2.13% with a term of one (1) year.

c) Not applicable.

Question #7

Ref: Energy Probe IR #68 &
Exhibit 4, Tab 2, Schedule 3

a) Please reconcile the increase of $52,606 in other OM&A Costs shown for the 2012 Test Year in Table EP 2-12 with the figure of ($18,994) as shown in Table 4-10.

b) Please confirm that if this change did not take place, the Closing Balance in Table EP 2-12 for the 2012 Test Year would be $6,185,661 and with the removal of $30,000 in charitable donations this figure would be $6,155,661, which matches the figure shown in the updated RRWF.

a) The total of 2012 OM&A shown in Table 4-10 should have shown $6,397,261 as per Exhibit 5, Tab 1, Schedule 2, page 6 resulting in other OM&A cost of $57,606 which is consistent with Table EP 2-12.

Cost of Capital

35.
Reference: Exhibit 5 / 1 / 1

a) Please provide a copy of the Promissory Note that is held by the Town of Halton Hills.
b) Have there been any changes to the note since it was first issued? If so please explain, and provide copies of the amendments.
c) Does the note have a fixed rate or is it variable or re-negotiated periodically? Please explain.
d) Please reconcile the information in Tables 5-2 through 5, which show a rate of 6.00%, with Table 5-7 which shows a rate of 6.25%.

Response:

a) Please refer to Appendix OEB 1-B.

b) There have been no changes to the principle amount of the Promissory Note.

c) The rate of interest is prescribed, from time to time, by the Treasurer of the Corporation of the Town of Halton Hills in accordance with the provisions of By-laws No. 00-100 and 01-130 of the Corporation of the Town of Halton Hills.

d) Table 5-2 through table 5-5 reflect the OEB approved 2008 Cost of Service Long – Term rate of 6.0%. Table 5-7 reflects the actual rate of 6.25% paid on the Long – Term Debt.

Cost Allocation

36.
Reference: Exhibit 7 / 1 / 1 / p. 2; Board Report "Review of Electricity Distribution Cost Allocation Policy", March 31, 2011 [EB-2010-0219]

The Board Report states, at p. 26

> *The Board is of the view that default weighting factors should be utilized only in exceptional circumstances….. [A]ny distributor that proposes to use those default values will be required to demonstrate that they are appropriate given their specific circumstances.*

APPENDIX OEB 1-B

PROMISSORY NOTE

Amount: $16,141,970.52 Due: December 31st, 2015

For value received, the undersigned, HALTON HILLS HYDRO INC., having offices at 43 Alice Street, Halton Hills (Acton), Ontario does hereby promise to pay to THE CORPORATION OF THE TOWN OF HALTON HILLS, or order, at the Town of Halton Hills, in the Province of Ontario, the sum of Sixteen Million One Hundred Forty-One Thousand Nine Hundred Seventy Canadian Dollars and Fifty-Two Canadian Cents (Cdn $16,141,970.52) on the last day of December, 2015.

This Promissory Note has been issued and delivered pursuant and subject to the provisions of By-laws No. 00-100 and 01-130 of The Corporation of the Town of Halton Hills upon maturity, and in replacement of the promissory note dated December 31st, 2010.

Interest shall be payable by Halton Hills Hydro Inc. to The Corporation of the Town of Halton Hills, or assign, at a rate of interest per annum, compounded annually not in advance, prescribed, from time to time, by the Treasurer of The Corporation of the Town of Halton Hills in accordance with the provisions of By-laws No. 00-100 and 01-130 of The Corporation of the Town of Halton Hills.

This Promissory Note may, at any time, be prepaid in full or, from time to time, in part, without notice, bonus or penalty.

Presentment, notice of dishonor, protest and notice of protest are hereby waived and the undersigned does hereby agree to remain as fully liable as if presentation, notice of dishonor, protest and notice of protest were duly made and given.

Dated and Delivered at the Town of Halton Hills, in the Province of Ontario, Canada, this 17th day of December, 2010.

HALTON HILLS HYDRO INC.

By: ____________________
Arthur A. Skidmore, CMA
President & CEO

By: ____________________
David J. Smelsky, CMA
Chief Financial Officer

Probe, not VECC.

[Laughter]

MR. AIKEN: The first one you have answered or you will answer by way of undertaking. That is Energy Probe technical conference question 1. So I will skip to my second question, which is Energy Probe Technical Conference Question No. 2.

This deals with the 1,400 solar panels that are going to be installed. I have got a number of follow-up questions. The response indicates that the depreciation expense is based on 20-year life. And my question is: What is the basis for the determination that solar panels have a 20-year life?

MR. SKIDMORE: We feel that the 20-year life is a reasonable term for the depreciation. This is a system for our green energy initiative for distribution purposes, as well, with another renewable energy option.

From industry information that we have around solar panels, that was the information that we received, that 20 years is applicable.

MR. AIKEN: Okay, thank you. Part (b) of the response deals with the capital cost allowance, and you indicate that the CCA should be class 49 with a rate of 8 percent, and that gives a CCA expense or deduction of 56,000.

Now, in Energy Probe IR No. 39, it was indicated that you had used 5 percent as a CCA rate for this class, and that resulted in a $35,000 deduction for tax purposes.

So my question is: Are you now proposing to change that to $56,000?

MR. SKIDMORE: Yes, we are.

MR. AIKEN: Okay. Then sticking with the CCA rate, why are you not using CCA class 43.2, which is a 50 percent rate?

MR. SKIDMORE: This solar panel initiative, from our perspective, aligns with distribution system requirements in class 49.

I guess the fast write-off of 43.2 is more from an experimental nature, and our opinion is this isn't experimental.

MR. AIKEN: Moving on to Energy Probe Technical Conference Question No. 6, the $3,943,430 loan that is shown there at a rate of 2.13 percent with a term of one year -- you may have to pull up Energy Probe Interrogatory No. 62 as well.

My question is: Is this 3.9 million in addition to the $5 million noted in the response to part (a) of Interrogatory No. 62, which talks about new construction financing for the 2012 capital budget of $5 million?

[Witness panel confers]

MR. SMELSKY: The $5 million that is referred to in Interrogatory Response 62, the $5 million is not related to the $3 million that is in response to Technical Question No. 6.

MR. AIKEN: So it is in addition to the ––

MR. SMELSKY: If the five million were undertaken, it would be in addition to.

MR. AIKEN: When will the $3.9 million loan noted in Energy Probe Technical Conference Question No. 6, when does that term, the one-year term, expire?

MR. SMELSKY: The one-year term expires in August of 2012, this year.

MR. AIKEN: And what are your plans to replace that financing at that time?

MR. SMELSKY: The financing at that time, we would look at renewing the term, potentially with either the existing finance company, and/or look at what the market variability rates are to replace it.

MR. AIKEN: And when you say "renew the term" do you mean another one year extension, or is that unknown at this time, whether it would be one-year or a five-year loan?

MR. SMELSKY: That is unknown.

MR. AIKEN: Okay. And just back on the $5 million loan, in Energy Probe 62, you provided a range of rates and terms.

When do you expect this $5 million will actually be obtained? And what is the -- your current thinking on the term of the loan?

[Witness panel confers]

MR. SMELSKY: The undertaking of the $5 million loan would be looked at in tranches, as required, and corresponding with the capital program. And in regards to terms, we would look at the terms as the advancements are required.

MR. AIKEN: My next question deals with Energy Probe

At the present replacement rate, the in-service stock is well exceeding its expected asset useful life at a rate greater than the existing pole replacement rate.

For budgetary purposes HHHI has simply used proxy costs for pole replacements – the true cost will depend upon whether it is a guy pole or a distribution pole, the number of circuits, other distribution apparatus and joint use attachments on the pole for the latter case, and whether or not the pole replacement project is being carried out as a road-widening or similar municipal infrastructure improvement project.

Interrogatory # 18

Ref: Exhibit 2, Tab 3, Schedule 4

The evidence indicates that HHHI capitalizes, through internal cost allocations, any indirect administration support costs such as Finance, Human Resources or Corporate Services. Is this true under both CGAAP and MIFRS?

Response:

No. This is only true under CGAAP.

Interrogatory # 19

Ref: Exhibit 2, Tab 3, Schedule 7

a) **Please explain how HHHI determined that the number of panels to be installed in 2012 would be 1,400.**

b) **What information does HHHI have with respect to the technology that is being used in other North American and international jurisdictions? Please provide all such information.**

c) **Will HHHI, one of its affiliates, or a third party or parties, own the solar panels connected to the HHHI panels?**

d) **How does HHHI propose to deal with the cost of energy produced by these solar panels? Will the individual panels be metered?**

e) **What is the expected generation associated with the 1,400 solar panels on a typical summer day and on a typical winter day?**

f) Please explain how the installation of these solar panels will result in reduced non-commodity charges.

g) Has HHHI done any analysis to determine the reduction in losses?

h) Has HHHI done any cost benefit analysis to determine what the net impact on ratepayers of including $1.4 million in rate base is?

Response:

a) HHH determined the number of eligible poles by using the following criteria:

- Secondary conductor attached to pole (120v)
- No tree or building shading now or projected for future
- Direct sunlight at 180 degrees from 10 AM until 3 PM
- Pole space availability 4.5m from ground

b) The technology is being demonstrated in over 50 utility companies worldwide in Australia, Hawaii, Tampa Electric (TECO), Orlando Utilities Commission (OUC), Atlantic City Electric (ACE), Northeast Utilities (NU), San Diego Gas and Electric (SDG&E), and Kingdom Electricity (KEC) in Jordan. The largest deployment to date is in, Public Service Electricity and Gas Co (PSE&G) in New Jersey for deployment of 40 MW consisting of a solar unit on 200,000 utility poles in PSE&G's service territory.

c) It is anticipated the HHHI will own the solar panels.

d) HHHI propose that any power production, line loss reduction and transmission savings will be directly passed onto the customer through Deferral and Variance accounts.

e) The performance of these four units has produced power to the secondary system at the rate of 0.78 kWh per day through all seasonal weather conditions, which is indicative of their long term performance. A range of 0.01 kWh to 1.80 kWh has been the highs and lows of the system to date.

f) The electricity from the units is generated locally and directly placed on the secondary voltage lines where it is consumed by HHHI customers.

g) The expected line loss reduction could be calculated as follows:

1,400 panels x .78kWh x 365 days = 398,590 kWh

2010 kWh purchases 520,541,000 kWh

398,590/520,541,000 = .076%

Applied for loss factor 6.02% x (1-.0076) = 6.01

h) HHHI's cost benefit analysis is presented below:

Revenue Requirement	$91,467
Deferral Account Offsets	$35,496
Difference	$55,971

There are also non-financial benefits associated with these units. Specifically, environmental benefits in terms of a reduced carbon footprint for the utility, improved efficiency that comes with distributed generation, improved public awareness about renewable energy options, and future smart grid opportunities.

Interrogatory # 20

Ref: Exhibit 2, Tab 4, Schedule 2, page 1

Please explain how the cost of power calculations are affected by MIFRS.

Response:

The cost of power calculation is not affected by MIFRS. It should remain the same under CGAAP and MIFRS.

Table EP 2-3 : Difference in Total Capital Expenditures Between CGAAP and MIFRS

	Total After Contributed Capital	Contributed Captial	Total Before Contributed Capital
CGAAP	7,548,752	1,396,208	8,944,960
MIFRS	7,376,995	1,284,968	8,661,963
Difference	171,757		282,997

c) The difference of $282,997 is close to the OM&A difference of $286,622.

Interrogatory # 54
Reference: Energy Probe Interrogatory #17

Do the expenditures shown for 2013 through 2015 include any amounts related to the transformer station and/or the distribution substation noted on page 12 of Exhibit 2, Tab 2, Schedule 3? If not, what are the total costs associated with each of these projects?

The expenditures shown for 2013 through 2015 do not include estimates for the transformer station and the municipal substation. The estimated cost of the Transformer Station is $15,000,000 and the estimated cost of the Distribution Substation is $1,250,000.

Interrogatory # 55
Reference: Energy Probe Interrogatory #19

a) Please provide all the calculations and assumptions used to generate the revenue requirement and deferral account offset figures shown in part (h) to the response.

b) Does the inclusion of the panels on the 1400 poles result in any lost or potential lost revenue associated with pole rentals for other purposes?

a) The calculations and assumptions used to generate the revenue requirement and deferral account offset figures shown in response to EP #19 h) is presented below in Table EP 2-4 and Table EP 2-5 respectively.

Table EP 2-4 : Calculations for Revenue Requirement

Capital Expenditure		1,400,000
Depreciation Expense		35,000
Net Book Value		1,365,000
Fixed Assets Opening Balance 2012		-
Fixed Assets Closing Balance 2012		1,365,000
verage Fixed Asset Balance for 20		682,500
Working Capital Allowance		-
Rate Base		682,500
Regulated Rate of Return		6.66%
Regulated Return on Capital		45,433
Deemed Interest Expense		19,716
Deemed Return on Equity		25,717
Regulated Return on Capital		45,433
Depreciation Expense		35,000
		80,433
Pils	26.25%	11,926
Revenue Requirement		92,359

Table EP 2-5 : Deferral Account Offset Figures

	kWh/kW	Loss Factor	Loss Adjusted	Rates	Charge
Power Purchased	398,580	1.0602	422,575	0.07298	$ 30,839
Charges-WMS	398,580	1.0602	422,575	0.00520	$ 2,197
Charges-NW	399	1.0000	399	2.65000	$ 1,056
Charges-CN	399	1.0000	399	2.14000	$ 853
Rural Rate Assistance	398,580	1.0602	422,575	0.00130	$ 549
TOTAL					**$ 35,495**

b) The inclusion of the 1400 panels on poles will not result in any loss or the potential of any lost pole rental revenue.

Interrogatory # 56

Halton Hills Hydro Inc.
EB-2011-0271
Responses to Energy Probe
Technical Conference Questions

Question #1

Ref: Energy Probe IR #49 &
Exhibit 2, Tab 2, Schedule 1 &
Energy Probe IR #50

a) Please provide updated fixed asset continuity schedules for 2011 and 2012, in both CGAAP and IFRS (Tables 2-10a, 2-10b, 2-11a and 2-12a as shown in Exhibit 2, Tab 2, Schedule 1) that reflect the actual capital expenditures in 2011 (Table EP 2-2 shown in EP IR #49), along with the current capital expenditure forecast for 2012 based on the carryover to 2012 shown in Table EP 2-2 and any other changes Halton Hills is proposing for 2011 and 2012 (such as including the land in rate base as noted in Energy Probe IR #50).

b) Please provide similar schedules as requested in (a) above, but excluding the land for the transformer station and distribution substation.

a) HHHI will undertake to provide a response.

b) HHHI will undertake to provide a response.

Question #2

Ref: Energy Probe IR #55

a) What is the life of the panels used for depreciation purposes?

b) What is the CCA deduction available in 2012 associated with the panels? Please show the calculation, including the CCA rate used.

c) The PILS figure of $11,926 shown in Table EP 2-4 appears to be 26.25% of the regulated return on capital, which includes debt costs. Please explain why the PILS calculation is not based on taxable income based on the return on equity ($25,717), increased by depreciation and reduced by the available CCA? Please calculate the PILS based on this approach.

a) The life of the panels used for accounting depreciation purposes is 20 years with the half year rate rule in year 1.

b) The CCA class shown in Table 4-27 should be shown as CCA class 49 with a corresponding CCA value of $56,000.

CCA Expense = [Capital Cost] X [CCA Rate] X [Half-year rate rule]
$56,000 = [$1,400,000] X [8%] X [50%]

c) The updated PILs calculation is presented below as Table EP TC-1.

Table EP TC-1 : Updated PILs Calculation

Capital Expenditure		1,400,000
Depreciation Expense		35,000
Net Book Value		1,365,000
Fixed Assets Opening Balance 2012		-
Fixed Assets Closing Balance 2012		1,365,000
Average Fixed Asset Balance for 2012		682,500
Working Capital Allowance		-
Rate Base		682,500
Regulated Rate of Return		6.66%
Regulated Return on Capital		45,433
Deemed Interest Expense		19,716
Deemed Return on Equity		25,717
Regulated Return on Capital		45,433
Depreciation Expense		35,000
		80,433
Pils		1,679
Revenue Requirement		82,111
CCA		56,000
(1,400,000 x 8% x 50%)		
Pils		25,717
Add Depreciation		35,000
Less CCA	-	56,000
		4,717
Pils		1,238
Gross Up - Pils	$	1,679

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

reiterate that the onus is on the distributor that is making an application for rates to document the actual amount and cost of embedded long-term debt and, in a forward test year, forecast the amount and cost of new long-term debt to be obtained during the test year to support the reasonableness of the respective debt rates and terms.

The following guidelines are relevant with respect to the determination of the amount and cost of long-term debt for electricity distribution utilities.

The Board will primarily rely on the embedded or actual cost for existing long-term debt instruments. The Board is of the view that electricity distribution utilities should be motivated to make rational decisions for commercial "arms-length" debt arrangements, even with shareholders or affiliates.

In general, the Board is of the view that the onus is on the electricity distribution utility to forecast the amount and cost of new or renewed long-term debt. The electricity distribution utility also bears the burden of establishing the need for and prudence of the amount and cost of long-term debt, both embedded and new.

Third-party debt with a fixed rate will normally be afforded the actual or forecasted rate, which is presumed to be a "market rate". However, the Board recognizes a deemed long-term debt rate continues to be required and this rate will be determined and published by the Board. **The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances**. These circumstances include:

- For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario *Business Corporations Act, 1990*) with a fixed rate, the deemed long-term debt rate <u>at the time of issuance</u> will be used as a ceiling on the rate allowed for that debt.

- For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.

- The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.

- For debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. Debt that is callable, but not within the period to the end of the test year, will have its debt cost considered as if it is not callable; that is the debt cost will be treated in accordance with other guidelines pertaining to actual, affiliated or variable-rate debt.

- A Board panel will determine the debt treatment, including the rate allowed based on the record before it and considering the Board's policy (these Guidelines) and practice. The onus will be on the utility to establish the need for and prudence of its actual and forecasted debt, including the cost of such debt.

Deemed Long-term Debt Formula for Electricity Distributors

While the Board is of the view that greater reliance should be placed on embedded debt, including forecasts of the amount and cost of new debt expected to be incurred during the test year, the Board recognizes that there is a continuing need for a deemed long-term debt rate.

While there were no specific suggestions for how the deemed long-term debt rate should be calculated, **the Board sees merit in modifying the formula in a manner consistent with the changes adopted for the ROE adjustment formula**.

Specifically, the Board considers that **the deemed long-term debt rate for the test year should be an estimate based on the long (30-year) Government of Canada bond yield forecast plus the average spread between an A-rated Canadian utility bond yield and 30-year Government of Canada bond yield for all business days in the month three (3) months in advance of the (proposed) effective date for the rate changes**. This change is only in the source of the data, in the following ways:

	Halton Hills OM&A			
	Excluding Property Taxes	Property Taxes	Including Property Taxes	Source
2008 Board Approved	5,124,000			Ex. 4, Tab 1, Sch. 1, Table 4-1
2008 Actual	5,075,057	92,063	5,167,120	BS 23, EP 37
2009 Actual	4,426,162	89,315	4,515,477	BS 23, EP 37
2010 Actual	4,379,882	95,553	4,475,435	BS 23, EP 37
2011 Actual - CGAAP Estimated	4,550,101	96,839	4,646,940	Undertaking JT1.10, EP 37
2012 Forecast - CGAAP Revised	5,880,800	106,600	5,987,400	BS 23, Sett. Agrmt.
Increase due to MIFRS vs. CGAAP			286,621	EP 35
2012 Forecast - MIFRS Revised	6,167,421	106,600	6,274,021	Setlement Agreement

UNDERTAKING NO. JT1.10: To provide full year 2011 OM&A CGAAP for School Energy Coalition.

RESPONSE:

Please see Table JT-15 for the 2011 preliminary full year OM&A in CGAAP format.

Table JT-15 : 2011 Preliminary year end OM&A in CGAAP Format

2011 OM&A - CGAAP	
Distribution Expenses - Operation	536,089
Distribution Expenses - Maintenance	360,051
Billing and Collecting	1,197,615
Community Relations	-
Administrative and General Expenses	2,456,346
Taxes Other than Income Taxes	102,500
Less: Capital Taxes within 6105	
Total	**4,652,601**
Less: Taxes Other than Income Taxes	102,500
Add: Charitable Donations	30,000
Total Per Table EP 1 -32 (EP# 35)	**4,580,101**

Employee Compensation and Benefits

HHHI has set out the information in Table 4-16 below according to Section 6-4 of the 2007 EDR Handbook where it states "For an applicant with fewer than three employees, reporting of employee compensation under this section is not required. In cases where there are three or fewer, full time equivalents (FTEs) in any category, the applicant may aggregate this category with the category to which it is most closely related. This higher level of aggregation may be continued, if required, to ensure that no category contains three or fewer FTEs." HHHI has aggregated the executive and management together in the management category.

Employee complement, compensation and benefits are set out in Table 4-16 below.

Table 4-16: Employee Costs (consistent with Board Appendix 2-K)

	2008 Board Approved	Average	2008 Actual	Average	2009 Actual	Average	2010 Actual	Average	2011 Bridge Year	Average	2012 Test Year	Average
Number of employees (Full-time equivalents (FTE's))												
Management	10		10		9		9		10		11	
Unionized	36		36		35		35		37		40	
Total Number of Employees	**46**		**46**		**44**		**44**		**47**		**51**	
Compensation (Total Salary and Wages)												
Management	$1,075,336	$124,626	$1,183,906	$118,391	$1,008,518	$112,058	$ 971,603	$107,956	$ 978,763	$ 97,876	$ 1,032,983	$ 93,908
Unionized	$2,746,390	$ 76,289	$2,252,251	$ 62,563	$2,100,940	$ 60,027	$2,304,387	$ 65,840	$ 2,466,972	$ 66,675	$ 2,893,134	$ 72,328
Total Compensation (Salary and Wages)	**$ 3,821,726**	**$ 200,915**	**$ 3,436,157**	**$ 180,953**	**$ 3,109,458**	**$ 172,084**	**$ 3,275,991**	**$ 173,796**	**$ 3,445,735**	**$ 164,551**	**$ 3,926,117**	**$ 166,236**
Compensation (Total Benefits)												
Management	$ 210,860	$ 21,086	$ 176,628	$ 17,663	$ 185,226	$ 20,581	$ 180,867	$ 20,096	$ 228,995	$ 22,899	$ 274,705	$ 24,973
Unionized	$ 562,635	$ 15,629	$ 493,734	$ 13,715	$ 554,203	$ 12,733	$ 611,992	$ 17,485	$ 618,670	$ 16,721	$ 827,630	$ 20,691
Total Compensation (Total Benefits)	**$ 773,495**	**$ 36,715**	**$ 670,362**	**$ 31,378**	**$ 739,429**	**$ 33,314**	**$ 792,859**	**$ 37,582**	**$ 847,664**	**$ 39,620**	**$ 1,102,335**	**$ 45,664**
Compensation (Total Incentives)												
Management	$ 70,923	$ 7,092	$ 52,742	$ 5,274	$ 11,082	$ 1,231	$ 25,797	$ 2,866	$ 65,820	$ 6,582	$ 77,376	$ 7,034
Unionized	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Compensation (Total Incentives)	**$ 70,923**	**$ 7,092**	**$ 52,742**	**$ 5,274**	**$ 11,082**	**$ 1,231**	**$ 25,797**	**$ 2,866**	**$ 65,820**	**$ 6,582**	**$ 77,376**	**$ 7,034**
Total of Costs Charged to OM&A & Capital												
Total of Costs Charged to OM&A	$3,222,369	$178,435	$ 3,326,721	$ 72,320	$ 2,836,303	$ 61,995	$ 3,127,045	$ -	$ 3,156,076	$ -	$ 3,689,022	$ -
Total of Costs Charged to Capital	$ -	$ -	$ 832,540	$ -	$ 1,023,666	$ -	$ 967,602	$ -	$ 1,203,143	$ -	$ 1,416,806	$ -

c) The percentage of the total potential incentives actually paid out were 42.6% in 2008 (refer to Exhibit 4, Tab 2, Schedule 3 for explanation), 77.7% in 2009 and 89.7% in 2010.

Interrogatory # 68

Reference: Board Staff Interrogatory #28 & Exhibit 4, Tab 2, Schedule 3, Table 4-10

a) HHHI indicates that it will remove $135,000 related to MDMR costs from the 2012 revenue requirement. Was this amount included in the smart meter expenses line shown as a cost driver in Table 4-10 of Exhibit 4, Tab 2, Schedule 3? If not, please indicate which driver the MDMR costs are included in.

b) Please provide an updated Table 4-10 to reflect the removal of the MDMR costs and any other changes that result from the interrogatory responses.

a) Yes. This amount was included in the smart meter expenses line shown as a cost driver in Table 4-10 of Exhibit 4, Tab 2, Schedule 3.

b) A revised Table 4-10 is provided as Table EP 2-12 below.

Table EP 2-12 : Revised Table 4-10 from Application

OM&A	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year	Cumulative	% Change
Opening Balance	$ 5,111,058	$ 5,111,058	$ 4,436,426	$ 4,386,371	$ 4,804,910	$ 5,111,058	
Change in Salaries and Wages (Note 1)		-$ 368,359	$ 181,248	$ 209,767	$ 300,743	$ 323,399	
Change in Benefit Costs		$ 69,067	$ 53,430	$ 54,806	$ 254,671	$ 431,974	
Smart Meter Labour Costs (Note 2)				$ -	$ 191,195	$ 191,195	
Smart Meter Expenses (Note 2)				$ -	$ 136,515	$ 136,515	
Tree trimming (Note 3)				$ 20,000	$ 230,000	$ 250,000	
Reduction in Contract Services Cost		-$ 130,000	-$ 40,601			-$ 170,601	
Reduction in Charitable Donation		-$ 20,905				-$ 20,905	
Reduction in Maintenance of General Plant			-$ 143,210			-$ 143,210	
Additional OM&A resulting from Modified IFRS				$ 206,419	$ 286,621	$ 493,040	
Other OM&A costs (Note 4)		-$ 224,435	-$ 100,922	-$ 72,453	$ 57,606	-$ 340,204	
Closing Balance	**$ 5,111,058**	**$ 4,436,426**	**$ 4,386,371**	**$ 4,804,910**	**$ 6,262,261**	**$ 6,262,261**	**22.52%**

(1) 2009 reduction relates to the impact of staffing changes and severances paid in 2008
(2) Smart Meter OM&A including incremental Labour costs
(3) Incremental increase in Tree Trimming costs
(4) Variances relating to changes in allocation methodologies and cost drivers in 2009 and 2010

Interrogatory # 34

Ref: Exhibit 4, Tab 1, Schedule 1, Table 4-1

Please provide the actual year-to-date expenditures for the most recent period available in 2011 in the same level of detail as shown in Table 4-1 (i.e. Operations, Maintenance, Billing and Collecting, Community Relations, Administrative and General and Total OM&A Expenses). Please also provide the figures for the corresponding period in 2010.

Response:

Reporting OM&A in the USoA format requires a manual mapping process that is preformed annually by HHHI for reporting to the OEB. Currently year to date OM&A is not available in the USoA format.

Interrogatory # 35

Ref: Exhibit 4, Tab 2, Schedule 2, Table 4-9

Please provide a table in the same level of detail as shown in Table 4-9, but with the 2011 and 2012 figures based on CGAAP, consistent with 2008 through 2010 data, with a bottom line adjustment to reflect the increased OM&A costs in each of 2011 and 2012 due to the change from CGAAP to MIFRS.

Response:

Table 4-9 with the 2011 and 2012 figures based on CGAAP, consistent with 2008 through 2010 data and with a bottom line adjustment to reflect the increased OM&A costs in each of 2011 and 2012 due to the change from CGAAP to MIFRS is presented below as Table EP 1-32.

EB-2011-0271
Response of Halton Hills Hydro Inc. to
Energy Probe Interrogatories
November 16, 2011

Table EP 1-32 : Revised Table 4-9 from Application

USoA	Description	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
	Operations					
5005	Operation Supervision and Engineering	$ 181,547	$ 301,623	$ 137,107	$ 251,144	$ 261,670
5010	Load Dispatching	$ -	$ -	$ -	$ -	$ -
5012	Station Buildings and Fixtures Expense	$ 1,023	$ 57	$ 4,385	$ 4,000	$ 4,000
5014	Transformer Station Equipment - Operation Labour	$ -	$ -	$ -	$ -	$ -
5015	Transformer Station Equipment - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -
5016	Distribution Station Equipment - Operation Labour	$ 21,801	$ 157,120	$ 281,140	$ 15,166	$ 18,578
5017	Distribution Station Equipment - Operation Supplies and Expenses	$ 3,537	$ 18,319	$ 20,004	$ 798	$ 1,260
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 101,982	$ 146,927	$ 311,259	$ 35,556	$ 133,044
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ -	$ -	$ -	$ -	$ -
5030	Overhead Sub-transmission Feeders - Operation	$ -	$ -	$ -	$ -	$ -
5035	Overhead Distribution Transformers - Operation	$ -	$ -	$ -	$ -	$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	$ -	$ -	$ -	$ -	$ -
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ 3,633	$ 8,264	$ 1,894	$ 819	$ 1,295
5050	Underground Sub-transmission Feeders - Operation	$ 159,770	$ -	$ -	$ 55,703	$ 208,434
5055	Underground Distribution Transformers - Operation	$ 78,185	$ -	$ -	$ 27,259	$ 102,000
5060	Street Lighting and Signal System Expense	$ -	$ -	$ -	$ -	$ -
5065	Meter Expense	$ 101,901	$ 102,275	$ 85,780	$ 120,136	$ 205,396
5070	Customer Premises - Operation Labour	$ 4,087	$ -	$ -	$ 927	$ 1,465
5075	Customer Premises - Operation Materials and Expenses	$ -	$ -	$ -	$ -	$ -
5085	Miscellaneous Distribution Expenses	$ 38,063	$ 85,156	$ 50,584	$ 24,582	$ 29,564
5090	Underground Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ -	$ -	$ -	$ -	$ -
5096	Other Rent	$ -	$ -	$ -	$ -	$ -
Total Distribution Expenses - Operations		**$ 695,529**	**$ 819,741**	**$ 892,155**	**$ 536,089**	**$ 966,705**
	Maintenance					
5105	Maintenance Supervision and Engineering	$ 178,452	$ -	$ -	$ -	$ -
5110	Maintenance of Buildings and Fixtures - Distribution Stations	$ -	$ -	$ -	$ -	$ -
5112	Maintenance of Transformer Station Equipment	$ -	$ -	$ -	$ -	$ -
5114	Maintenance of Distribution Station Equipment	$ 120,490	$ 10,873	$ 21,018	$ 85,252	$ 104,190
5120	Maintenance of Poles, Towers and Fixtures	$ 41,005	$ 93,748	$ 149,942	$ 31,246	$ 35,112
5125	Maintenance of Overhead Conductors and Devices	$ 97,407	$ -	$ -	$ 21,963	$ 34,712
5130	Maintenance of Overhead Services	$ 96,141	$ -	$ -	$ 21,677	$ 34,261
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 121,968	$ -	$ -	$ 147,501	$ 393,464
5145	Maintenance of Underground Conduit	$ 17,714	$ 11,728	$ 19,813	$ 16,994	$ 19,313
5150	Maintenance of Underground Conductors and Devices	$ 16,821	$ -	$ -	$ 3,793	$ 5,994
5155	Maintenance of Underground Services	$ 20,559	$ 27,762	$ 60,827	$ 9,636	$ 12,326
5160	Maintenance of Line Transformers	$ 35,433	$ 29,025	$ 22,493	$ 21,989	$ 26,627
5165	Maintenance of Street Lighting and Signal Systems	$ -	$ -	$ 1,227	$ -	$ -
5170	Sentinel Lights - Labour	$ -	$ -	$ -	$ -	$ -
5172	Sentinel Lights - Materials and Expenses	$ -	$ -	$ -	$ -	$ -
5175	Maintenance of Meters	$ 5,363	$ -	$ -	$ -	$ -
5178	Customer Installations Expenses - Leased Property	$ -	$ -	$ -	$ -	$ -
5195	Maintenance of Other Installations on Customer Premises	$ -	$ -	$ -	$ -	$ -
Total Distribution Expenses - Maintenance		**$ 751,353**	**$ 173,136**	**$ 275,319**	**$ 360,051**	**$ 665,999**

Table EP 1-32 : Revised Table 4-9 from Application (cont'd)

USoA	Description	2008 Actual	2009 Actual	2010 Actual	2011 Bridge Year	2012 Test Year
	Billing and Collecting					
5305	Supervision	$ 90,463	$ 111,360	$ 106,650	$ 65,755	$ 226,871
5310	Meter Reading Expense	$ 134,104	$ 134,696	$ 131,177	$ 16,300	$ 206,840
5315	Customer Billing	$ 332,214	$ 424,460	$ 369,933	$ 590,390	$ 680,251
5320	Collecting	$ 350,642	$ 343,066	$ 405,420	$ 421,870	$ 466,428
5325	Collecting - Cash Over and Short	$ 112	$ -	$ 6,574	$ -	$ -
5330	Collection Charges	$ 2,759	$ 3,286	$ 2,412	$ 3,300	$ 3,300
5335	Bad Debt Expense	$ 102,222	$ 75,000	$ 89,264	$ 100,000	$ 100,000
5340	Miscellaneous Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -
Total Billing and Collecting Expenses		**$ 1,012,516**	**$ 1,091,868**	**$ 1,111,430**	**$ 1,197,615**	**$ 1,683,690**
	Community Relations					
5405	Supervision	$ -	$ -	$ -	$ -	$ -
5410	Community Relations - Sundry	$ -	$ -	$ -	$ -	$ -
5415	Energy Conservation	$ -	$ -	$ -	$ -	$ -
5420	Community Safety Program	$ -	$ -	$ -	$ -	$ -
5425	Miscellaneous Customer Service and Informational Expenses	$ -	$ -	$ -	$ -	$ -
5505	Supervision	$ -	$ -	$ -	$ -	$ -
5510	Demonstrating and Selling Expense	$ -	$ -	$ -	$ -	$ -
5515	Advertising Expenses	$ 6,864	$ 2,032	$ -	$ -	$ -
5520	Miscellaneous Sales Expense	$ -	$ -	$ -	$ -	$ -
Total Community Relations Expenses		**$ 6,864**	**$ 2,032**	**$ -**	**$ -**	**$ -**
	Administrative and General Expenses					
5605	Executive Salaries and Expenses	$ 635,320	$ 855,873	$ 822,658	$ 624,277	$ 642,187
5610	Management Salaries and Expenses	$ 351,057	$ 27,061	$ 26,498	$ 331,142	$ 352,870
5615	General Administrative Salaries and Expenses	$ 463,306	$ 546,540	$ 540,503	$ 815,200	$ 957,459
5620	Office Supplies and Expenses	$ 35,696	$ 35,277	$ 40,102	$ 66,700	$ 60,850
5625	Administrative Expense Transferred - Credit	$ -	$ -	$ -	$ -	$ -
5630	Outside Services Employed	$ 293,492	$ 163,690	$ 123,089	$ 54,000	$ 117,000
5635	Property Insurance	$ 46,573	$ -	$ 7,418	$ 155,000	$ 132,000
5640	Injuries and Damages	$ 48,151	$ 33,608	$ 4,515	$ -	$ -
5645	Employee Pensions and Benefits	$ 28,192	-$ 2,271	$ -	$ -	$ -
5650	Franchise Requirements	$ -	$ -	$ -	$ -	$ -
5655	Regulatory Expenses	$ 140,190	$ 61,795	$ 69,780	$ 124,447	$ 125,000
5660	General Advertising Expenses	$ 7,507	$ 4,172	$ 7,769	$ -	$ -
5665	Miscellaneous General Expenses	$ 77,890	$ 92,642	$ 78,826	$ 1,500	$ 3,000
5670	Rent	$ -	$ -	$ -	$ -	$ -
5675	Maintenance of General Plant	$ 488,285	$ 523,030	$ 379,820	$ 284,080	$ 297,280
5680	Electrical Safety Authority Fees	$ -	$ -	$ -	$ -	$ -
5685	Independent Electricity System Operator Fees and Penalties	$ -	$ -	$ -	$ -	$ -
5695	OM&A Contra Account	$ -	$ -	$ -	$ -	$ -
6205	Donations (Charitable Contributions)	$ 29,137	$ 8,232	$ 6,489	$ 30,000	$ 30,000
Total Administrative and General Expenses		**$ 2,644,796**	**$ 2,349,649**	**$ 2,107,467**	**$ 2,486,346**	**$ 2,717,646**
	Total OM&A -CGAAP	**$ 5,111,058**	**$ 4,436,426**	**$4,386,371**	**$ 4,580,101**	**$ 6,034,040**
Increase in OM&A as result of MIFRS					**224,809**	**286,621**
Total OM&A based on MIFRS					**$ 4,804,910**	**$ 6,320,661**

2012 Test Year vs. 2010 Actual

2012 Test Year OM&A of $6,320,661 is greater than the 2010 Actual OM&A of $4,386,371 by $1,934,290. The main drive of the increase in OM&A in 2012 compare to 2010 is presented below in Table EP 1-31.

Table 1-31 : Increase in OM&A 2010 vs. 2012

Increase in OM&A between 2010 and 2012		**Amount**
Smart Meter OM&A included in 2012		462,710
Increase in OM&A relating to the transitioning to MIFRS		493,040
Increase in Tree trimming cost of		250,000
Increase in wages costs		510,510
Increase in benefit costs		309,477
Other OM&A Costs		(91,447)
Increase in OM&A		**1,934,290**

b) The increase in OM&A expenses between 2010 and 2012 that is due solely to the movement to MIFRS is $286,621.

c) The increase in OM&A in 2012 as compared to 2010 for smart meter OM&A is $462,000. In 2010 all smart meter OM&A expenses were recorded in the variance account 1556.

d) In 2010 all OM&A expenses related smart meter were recorded in the deferral and variance account 1556 – Smart Meter OM&A Variance Account.

e) The increase in OM&A 2012 related to smart meters is included in the following accounts in Table 4-11.

Billing and Collecting		
USoA	**Description**	**2012 Test Year**
5305	Supervision	118,547
5310	Meter Reading Expense	190,300
5315	Customer Billing	153,863
Total Smart OM&A		**462,710**

Interrogatory # 58
Reference: Energy Probe Interrogatory #29, parts (e) and (f)

a) What is the basis for only allocating 50% of the gains on disposals in the revenue offset?

b) What assets are forecast to be disposed of in 2012 for a net gain of $25,000?

c) What is the project level of average excess cash that could be invested in 2012 and what is the interest rate currently available on short term GICs?

a) The basis for only allocating 50% of the gains on disposals in the revenue offset is based on the direction from the Board in the 2006 rate handbook sections 4.6.1 and 4.6.2.

b) The forecasted 2012 net gain of $25,000 is the estimated proceeds to be realized on the sale of a used bucket truck.

c) The projected level of average excess cash that could be invested in 2012 is $300,000. The current interest rates for short-term Term Deposits as posted by TD Canada Trust on January 12, 2012 are:

30-59 days	0.46%
60-89 days	0.61%
90-119 days	0.66%
120-179 days	0.66%
180-269 days	0.82%
270-364 days	0.82%

Interrogatory # 59
Reference: Energy Probe Interrogatory #33

The response indicates an increase related to smart meters of $462,710 which is broken down by account in part (e) of the response. The table provided in response to part (a) of the question provides the 2010 actual expenditures in these accounts. Please indicate what costs from 2010 in these three accounts (5305, 5310, 5315) have been reduced due to the movement to smart meters.

In 2010 all smart meter costs have been recorded in the deferral and variance account 1555 and 1556. Therefore, no costs from 2010 in these three accounts (5305, 5310, 5315) have been reduced due to the movement to smart meters.

Table EP 1-34 : The increase in OM&A between 2011 and 2012 after accounting for smart meter impacts

Increase in OM&A between 2011 and 2012 excluding Smart Meter Costs		Amount
Increase in OM&A between 2011 and 2012		1,515,751
Less: OM&A relating to Smart Meters		462,000
		1,053,751
Other Increase in OM&A between 2011 and 2012		
Increase in tree trimming costs		230,000
Increase in wages costs		300,743
Increase in benefit costs		254,671
Increase in OM&A relating to the transitioning to MIFRS		286,621
Other OM&A Costs		(18,284)
		1,053,751

Interrogatory # 37

Ref: Exhibit 4, Tab 1, Schedule 1, Table 4-1

a) **Please confirm that Table 4-1 does not include property taxes.**

b) **Please provide the actual property tax expense for 2008 through 2010 and the forecasts for 2011 and 2012. Please include any actual information available as part of the forecast for 2011.**

Response:

a) Confirmed.

b) The actual property tax expense for 2008 through 2011 and the forecast for 2012 are presented below in Table EP 1-35.

Table EP 1-35 : Actual Property Tax

	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Forecast
Municipal Property Taxes	$ 81,644	$ 83,946	$ 85,302	$ 87,753	$ 95,680
Pils Payment to Ontario Electricity Financial Corporation	$ 10,419	$ 5,369	$ 10,251	$ 9,086	$ 10,920
Total	**$ 92,063**	**$ 89,315**	**$ 95,553**	**$ 96,839**	**$ 106,600**

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March 12, 2012

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Your reference
EB-2011-0271

Our reference
01005480-0015

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Dear Ms. Walli:

Halton Hills Hydro Inc.
Distribution Rates 2012 (EB-2011-0271)

We are counsel to Halton Hills Hydro Inc. ("HHH") in the above-captioned matter.

In the context of settlement discussions, HHH agreed to provide interested parties with a copy of the report HHH commissioned for the purposes of planning and developing its line clearance and tree trimming program.

In accordance with the Board's *Practice Direction on Confidential Filings* ("Practice Direction"), HHH is filing this document in confidence. The report was prepared by a third party consultant – Horizon Contracts Management Company Inc. ("HCMC") – and provides the line clearance and tree trimming costs referenced in HHH's 2012 electricity distribution cost of service application. HCMC helps manage line clearance and tree trimming, but does not perform the actual line clearance and tree trimming work – this must be contracted out to other service providers.

The confidentiality request relates to the entire document.

Appendix A to the Practice Direction sets out various factors the Board may consider when determining requests for confidentiality. These include, among others:

(a) the potential harm that could result from the disclosure of the information, including:

i. prejudice to any person's competitive position;

ii. whether the information could impede or diminish the capacity of a party to fulfill existing contractual obligations;

iii. **whether the information could interfere significantly with negotiations being carried out by a party**; and

iv. whether the disclosure would be likely to produce a significant loss or gain to any person;

(b) whether the information consists of a trade secret or financial, commercial, scientific, or technical material that is consistently treated in a confidential manner by the person providing it to the Board;

(c) **whether the information pertains to public security**;…

> (g) **any other matters relating to FIPPA and FIPPA exemptions**; [emphasis added]

With respect to item (g) above, the Board has provided a summary of pertinent FIPPA provisions at Appendix E of the Practice Direction. That summary provides, in part, as follows:

> Under section 17(1), the Board must not, without the consent of the person to whom the information relates, disclose a record where:
>
> (a) the record reveals a trade secret or scientific, technical, commercial, financial or labour relations information;
>
> (b) the record was supplied in confidence implicitly or explicitly; and
>
> (c) disclosure of the record could reasonably be expected to have any of the following effects:
>
> > i. **prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of a person, group of persons or organization**;
> >
> > ii. result in similar information no longer being supplied to the Board where it is in the public interest that similar information continue to be so supplied;
> >
> > iii. result in undue loss or gain to any person, group, committee or financial institution or agency; [emphasis added]

HHH will not tender or negotiate a line clearance and tree trimming contract with external service providers until the Board renders a decision on its COS application. As a result, HHH requests that the report from HCMC remain confidential. The document contains projected financial costs and timelines that could significantly interfere with HHH's contractual or other negotiations pertaining to the proposed work. Should prospective service providers for this work have access to the report, it could reasonably be expected to prejudice HHH's negotiating position in any contract talks.

In addition, HCMC's report goes beyond the purview of establishing budgetary projections and opines on matters that are sensitive and immaterial for the purposes of this proceeding. Certain passages discuss hypothetical issues of public security and safety (a factor mentioned above at subsection (c)) and also discuss perceived liability issues that are beyond the scope of HCMC's expertise. HHH is concerned that putting these passages on the public record could interfere significantly with negotiations for the proposed work. They could also, in theory, interfere with other future negotiations (e.g. insurance contracts).

HHH will be delivering, under separate cover, copies of the subject material to the Board in confidence in accordance with the Practice Direction. HHH will also be delivering copies in confidence to those of the parties' counsel and/or consultants who have executed the Board's form of Declaration and Undertaking with respect to confidentiality, subject to HHH's right to object to the Board's acceptance of a Declaration and Undertaking from any person.

As required under the Practice Direction, HHH has attached to this cover letter a non-confidential summary of the document that can be served on all parties and placed on the public record.

NORTON ROSE

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,

“Signed”

John Beauchamp

JB/mnm

Enclosure

Cop(y/ies) to: All Intervenors in EB-2011-0271
Art Skidmore (HHH)
David Smelsky (HHH)

Non-confidential description of document requested to be kept confidential

Halton Hills Hydro Inc. Line Clearance and Tree Trimming Report – May 5, 2011

This document represents the final deliverable of an engagement to assist Halton Hills Hydro Inc. ("HHH") in the planning and development of its line clearance and tree trimming program. The document provides the line clearance and tree trimming costs used in HHH's 2012 electricity distribution cost of service application.

In early 2011, HHH engaged Horizon Contracts Management Company Inc. ("HCMC") to help develop a tree trimming and line clearance budget (for the purposes of completing the OM&A component of HHH's 2012 electricity distribution cost of service application). The document was prepared by Brian Lang, a certified arborist at HCMC, who has been involved with the logistics and operation of HHH's line clearance and tree trimming program since 2009. Mr. Lang's key observations and recommendations are presented in this report. They are as follows:

- The high tree growth rate, along with the excessive disease and die back of mature trees in recent years, has contributed to significant tree growth and encroachment in HHH's service area. Small saplings that have been trimmed in recent years (as opposed to eradicated) will also be a significant factor in HHH's line clearance and tree trimming program.

- HHH's line clearance program has been under-funded for a significant number of years, and tree encroachment issues are prevalent throughout much of HHH's system.

- To get HHH to a position where only routine line clearance and tree trimming maintenance is required, HHH's program will need to exceed one complete three-year cycle.

- Mr. Lang's report proposes two models for addressing HHH's line clearance and tree trimming needs:

    1) The first model would involve a front-loaded "blitz", whereupon HHH's entire system is brought up to standard in the first year of the program, followed by regular maintenance.

    2) The second model is not as heavily front-loaded as the first model, and conceives a gradual return to a three-year maintenance cycle.

- Mr. Lang comments that the immediate cost impact of the first model is significant. The long term variance in cost impact between the two models over the course of a nine-year period – which Mr. Lang claims is the appropriate reference when establishing and analyzing an effective line clearance maintenance program – works out to be approximately 5% in favour of the second model.

- Mr. Lang also recommends a re-structuring of the area delineation boundaries after the first year of the program.