Halton Hills
HYDRO

Board Secretary
Ontario Energy Board
2300 Yonge St
27th Floor
Toronto, ON M4P 1E4

November 16, 2011

Dear Ms. Walli,

Re: Halton Hills Hydro Inc. Interrogatory Responses to OEB Board Staff in proceeding EB-2011-0271

Halton Hills Hydro Inc. ("HHHI") hereby submits its responses to OEB Board Staff Interrogatories to the Ontario Energy Board ("the Board").

Please find attached to this cover letter:

- 2 paper copies of the Interrogatory Responses to OEB Board Staff in proceeding EB-2011-0271.
- 1 electronic copy of the Interrogatory Responses to OEB Board Staff in proceeding EB-2011-0271.

A copy of the Interrogatory Responses to OEB Board Staff has also been filed through the Web Portal and electronic copies forwarded to all intervenors in EB-2011-0271.

In the event of any additional information, questions or concerns, please contact David Smelsky, Chief Financial Officer, at dsmelsky@haltonhillshydro.com or (519) 853-3700 extension 225, or Tracy Rehberg-Rawlingson, Regulatory Affairs Officer, at tracyr@haltonhillshydro.com or (519) 853-3700 extension 257.

Sincerely,

(Original signed)

David J. Smelsky, CMA
Chief Financial Officer
Halton Hills Hydro Inc.

Cc: Arthur Skidmore, President & CEO, HHHI
Richard King, Counsel to HHHI
Intervenors in proceeding EB-2011-0271

HHHI Response to
Board Staff (OEB) Interrogatories
EB-2011-0217

1.

Following publication of the Notice of Application, did HHHI receive any letters of comment? If so, please confirm whether a reply was sent to the author of the letter. If confirmed, please file that reply with the Board. If not confirmed, please explain why a response was not sent and confirm if HHHI intends to respond.

Response:

No letter(s) of comment were received following publication of the Notice of Application.

Rate Base Assets

2.

Reference: Exhibit 2 / 3 / 4 / p. 1

International Accounting Standard ("IAS") 16 'Property, Plant and Equipment' states that the cost of PP&E comprises any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized on qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

HHHI stated at the referenced page:

> *HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year. HHHI capitalizes, through internal cost allocations, any indirect administrative support costs such as Finance, Human Resources or Corporate Services.*

a) Please explain why HHHI capitalizes indirect administrative support costs such as Finance, Human Resources or Corporate Services when IAS 16 states that only "directly attributable" costs can be capitalized. Please identify if and when HHHI will change its policy and practices of capitalizing the indirect administration support costs. If not, why not.

b) It appears that HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed for a period of less than one year. Please confirm.

c) If answer to part "b" is yes, does HHHI concur that IAS 23 requires that directly attributable borrowing costs are capitalized upon qualifying assets that may take a substantial period of time to get ready for its intended use or sale? If so, does HHHI plan to change its capitalization policy for the attributable borrowing costs? If not, why not?

Response:

a) The reference above is in relation to HHHI's Capitalization Policy under Canadian Generally Accepted Accounting Principles (CGAAP). Under IFRS, HHHI will capitalize all costs, including burdens, when the costs are directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management. Any general and indirect administrative support costs currently included in the various burden rates under CGAAP will not be capitalized under IFRS.

b) Historically, HHHI does not capitalize interest on funds used during construction as there has not been the need to borrow funds for the capital projects.

c) Yes, HHHI concurs with IAS 23. Eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets. Interest rate to be used for capitalization will be limited to the OEB's published rate for CWIP for regulatory reporting purposes.

3.

References: Exhibit 2 / 3 / 4 / p. 1; Report of the Board *'Transition to International Financial Reporting Standards'* ("IFRS"), July 28, 2009 [EB-2008-0408]

The Board Report said at p. 15:

> *The utility will file a copy of its capitalization policy, identifying any updates to the policy, as part of its first rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified.*

HHHI proposed that its test year be based on the Modified International Financial Reporting Standards ("MIFRS").

a) Please provide a copy of the capitalization policy from the adoption of MIFRS.

b) Please detail all changes to accounting policies arising from the adoption of MIFRS.

c) Please state the impact on the revenue requirement of the changes due to:

   i. Changes to the accounting policies due to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement,

   ii. Changes to the capitalization policies due to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement, and

   iii. Other changes to the capitalization since 2008 that are not related to MIFRS to each major component of the revenue requirement (e.g. rate base, operating costs, etc), including the overall dollar impact on the proposed revenue requirement.

Response

a) Please refer to Appendix OEB 1-A.

b) Please refer to Appendix OEB 1-A.

c)

   i. Please refer to HHHI interrogatory response to Energy Probe question 6.

   ii. Please refer to HHHI interrogatory response to Energy Probe question 6.

   iii. No changes to the capitalization policy for 2008, 2009, 2010 and 2011

4.

References: Report of the Board *'Transition to International Financial Reporting Standards* ("IFRS"), July 28, 2009 [EB-2008-0408]; Exhibit 2 / 3 / 4 / p.1

The Board Report has stated at p. 15:

> *The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS.*

IAS 16 Property, Plant and Equipment states that the cost of PP&E comprises of any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

IAS 23 states that directly attributable borrowing costs are capitalized upon qualifying assets only. It also indicated that a qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale.

The Board Report also stated at p. 40:

> *The Board will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the Board's published rates. Otherwise, the distributor should use the Board's published rates.*

HHHI stated in its Capitalization Policy (Exhibit 2 / 3 / 4):

> *HHHI does not capitalize interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year.*

With respect to the impact of MIFRS on capital expenditures:

a) Please confirm if the costs capitalized are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. If not, please explain.

b) Has HHHI consulted with its external auditors or professional advisors regarding the change in capitalization of overhead within IFRS requirements? If yes, please provide supporting documentation. If not, please identify if there is any plan in the near future for such a consultation.

c) Please identify the burden rates related to the capitalization of costs of self- constructed assets:

   i. Prior to transition (from the last rebasing application to January

      1, 2011), and

   ii. After transition (on or after January 1, 2011).

d) Please provide the following information in detail for overhead/burden costs on self-constructed assets for the bridge and test years.

	Dollar Impact		**Directly Attribut-able**	
Nature of the Overhead Costs	**Bridge Year**	**Test Year**	**Yes/No**	**Reasons for Capitalization (MIFRS Principles)**
1.				
2.				
3.				
4.				

e) Please identify the overall level of increase (decrease) in OM&A expense in the bridge and test year in relation to a decrease (increase) in capitalized overhead.

f) Please confirm that all borrowing costs that are directly attributable to the acquisition, construction, or production of PP&E costs are capitalized to PP&E and not expensed. If this is not the case, please explain.

g) Were the incurred debts (e.g. demand loan, smart meters, etc.) acquired on an arm's length basis?

h) Were the actual borrowing costs (in "d" above) capitalized for rate making purposes? If not, please explain.

i) If not acquired at arm's length, what are the actual interest rates and interest borrowing costs used? Were they greater than the Board's most recently published CWIP interest rates?

j) Please confirm that, if the interest rate used in "i" above is greater than the Board's most recently published CWIP interest rates, HHHI has used the Board's published rates to calculate borrowing costs included in the construction costs. If this is not the case, please explain.

k) Concerning HHHI's practice of not capitalizing interest on funds used during construction as capital projects are budgeted for and completed in the fiscal year, please state how many months in the fiscal year would the capital projects be completed.

l) How long do the interest rates on the borrowed funds used for construction in "g" above run for?

m) Please confirm that HHHI followed the standard in IAS 23. If not, please explain.

Response:

a) If the costs are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management, then as per HHHI IFRS Capitalization Policy (Appendix OEB 1-A) eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets.

b) Yes, HHHI has consulted with its external auditors regarding the change in capitalization of overhead within IFRS requirements. Please refer to Appendix OEB 1-A

c) HHHI burden rates related to the capitalization of costs of self- constructed assets is presented below in Table OEB 1-1.

Table OEB 1-1 : HHHI Burden Rates

HHHI Burden Rates			
	Effective 1-Sep-10	Effective 1-Apr-11	Effective 1-Apr-12
Hourly Labour Charge	$ 78.45	$ 67.08	$ 67.08
Equipment Rates:			
Single Bucket Truck	$ 44.50	$ 46.00	$ 47.50
Double Bucket Truck	$ 44.50	$ 46.00	$ 47.50
Digger Derrick	$ 44.50	$ 46.00	$ 47.50
Dump Truck	$ 44.50	$ 46.00	$ 47.50
Tension Puller	$ 44.50	$ 46.00	$ 47.50
Pick-up Truck	$ 24.00	$ 25.00	$ 26.00
Van	$ 24.00	$ 25.00	$ 26.00
Skidsteer	$ 24.00	$ 25.00	$ 26.00
Fork Lift	$ 24.00	$ 25.00	$ 26.00
Pole Trailer	$ 14.50	$ 15.00	$ 15.50
Reel Trailer	$ 14.50	$ 15.00	$ 15.50
Material Overhead Rate	22%	12%	12%

d) Please refer to the Capitalization – Burden section of the IFRS Capitalization Policy provided in Appendix OEB 1-A.

e) The Bridge and Test OM&A increase by $206,419 and $286,621 respectively in relation to the decrease in capitalized overhead.

f) There were no borrowing costs incurred that are directly attributable to the acquisition, construction, or production of PP&E. Borrowing costs related to smart meters are currently recorded in OM&A and are not part of PP&E.

g) Yes.

h) Please refer to response to part f).

i) Not applicable, as the incurred debt is on an arm's length basis.

j) Not applicable.

k) Less than six (6) months.

l) Term loan to August 30, 2012.

m) HHHI confirms that the standard in IAS 23 – Borrowing Costs is correctly followed. See Appendix OEB 1-A.

5.
Reference: Exhibit 2 / 2 / 1 / p.6

There is no entry in Table 2-11a 'Asset Continuity Schedule' for Communications Equipment (Smart Meters) under account 1955.

Where is the capital cost of the infrastructure associated with Smart Meters accounted for?

Response:

All capital costs for smart meter have been included in USoA Account 1860.

6.
Reference: Report of the Board *'Transition to International Financial Reporting Standards ("IFRS")* July 28, 2009 [EB-2008-0408];

IFRS requires certain assets to be recorded as intangible assets (e.g. computer software and land rights) that were previously included in PP&E.

The Board Report has said at p. 40:

> *Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement.*

HHHI did not present in Exhibit 2 the accounting policy change on asset reclassification from PP&E to intangible assets.

a) Has HHHI identified the accounting policy change on asset reclassification from PP&E to intangible assets? If so, please provide the accounting policy change and quantify the changes due to the adoption of IFRS for the test year and bridge year. If not, please provide the reasons and the plan when this is to be addressed.
b) For the assets identified in (a), please propose a regulatory treatment in accordance with the Board report.

Response:

a) HHHI has not identified any accounting policy changes on asset reclassification from PP&E to intangible assets. HHHI only dealt with policy that impact revenue requirement. HHHI will address the policy issue relating to intangible assets in December of 2011.

b) Computer software and land rights were included in rate base and the amortization expense in depreciation expense in determining revenue requirement.

7.
Reference: Exhibit 2 / 1 / 2, pp. 9 & 13

For underground switchgear, HHHI stated at p. 9:

> *Kinectrics identifies a useful life between 20 and 40 years, with a typical useful life of 30 years based on low mechanical stress and 4 electrical loading and high environmental factors. Environmental factor is high as the assets tend to rust as they sit at the side of the road, so the snow, debris, salt, etc. factor into the condition of the asset. The approximate age is 25 to 30 years; therefore HHHI has decided a useful life of 30 years is appropriate.*

At p. 13 'Table 2-4: PP&E Components and Estimated Useful Life', HHHI has proposed a useful life of 20 years instead of 30 years for underground switchgear.

> Please clarify the figure for the useful life of the underground switchgear that HHHI has decided is appropriate, and make any necessary changes to subsequent tables.

Response:

The useful life for the underground switchgear is 30 years. HHHI has used the 30 years in calculating 2011 and 2012 depreciation expenses. The updated table is presented below as Table OEB 1-2.

Table OEB 1-2 : Revised Table 2-4 from Application

Component	Previous Component	Existing Useful Life	Proposed Useful Life	Minimum	Typical	Maximum
Land	Land	N/A	N/A			
Overhead poles, fully dressed	Overhead Poles	25	50	40	44	50
Overhead conductors	Overhead Conductors & Devices	25	50	50	60	77
Overhead line switches, reclosures, fault circuit indicators	Overhead Conductors & Devices	25	40	30	50	60
Municipal substations – transformers incl grounding system	MS Station equipment	25	35	32	45	55
Municipal substations - DC service station incl battery & chargers	MS Station equipment	25	20	10	20	30
M.S. Switchgear	Overhead Conductors & Devices	10	40	30	40	60
Underground primary cable incl utility chambers	Underground Conductors & Devices	25	40	30	40	60
Underground secondary cable	Underground Services	25	40	40	40	60
Underground ducts and transformer switchgear foundation	Underground Conduit	25	50	30	50	80
Overhead transformers incl voltage regulator	Overhead Transformers	25	40	30	40	60
Underground transformers incl fault indicators	Underground Transformers	10	40	30	40	40
Underground switchgear and junction cubicle		-	30	20	30	40
SCADA – battery, RTU, relay, IED		15	20	15	20	30
Industrial/Commercial, wholesale Energy Meters	Interval Meters – 1 Phase, 3 Phase & Meters YE Adj	25	20	20	30	60
PTs & CTs	Meters	25	45	30	45	50
Smart meters - meters	Meters	15	15	15	15	20
Smart meters - repeaters	Meters	15	15	5	10	15
Smart meters – data concentrators	Meters	15	15	10	20	20
Office Furniture and Equipment	Office Furniture and Equipment	10	5	5	10	15
Computer Equipment Hardware	Computer Equipment Hardware	5	3	3	4	5
Computer Software	Computer Software	1	2	2	4	5
Vehicles – bucket trucks	Transportation Equipment	5	12	5	10	15
Vehicles – trailers	Transportation Equipment	5	15	5	15	20
Vehicles – vans/cars	Transportation Equipment	5	8	5	8	10
Tools, Garage Equipment, Measurement & Testing Equipment	Tools, Garage Equipment, Measurement & Testing Equipment	10	10	5	8	10
Stores Equipment	Stores Equipment	10	10	5	8	10
Wireless Communication	Communication Equipment	-	10	2	5	10

8.
Reference: Exhibit 2 / 1 / 2 / pp. 12-13

HHHI application has a life of 3 years and two years for computer hardware and software respectively. Hardware assets have had expected useful life of 5 years, and for software it has often been 3 – 5 years. Table 2-4 shows that HHHI has used a one-year period for software.

a) Please provide the basis for HHHI's proposal for 3 and 2 year useful lives.

b) For how long has HHHI used a one-year life for computer software?

Response:

a) HHHI proposed to use 3 and 2 year useful lives for computer hardware and software respectively based on the ranges in the HHHI Kinectrics report.

b) Based on the accounting records, HHHI has been using the one-year life for computer software since 2001.

9.
References: Exhibit 2 / 2 / 4 / p. 2; Exhibit 2 / 2 / 5 / p. 1

In Exhibit 2 / 2 / 5, HHHI states: "In 2009 and 2010, HHHI removed $869,000 and $367,000 respectively from accumulated depreciation for stranded meter costs as a result of the Smart Meter project." However, Table 2-19 shows variances that are much smaller than these amounts for Account 1860 - Meters.

Please provide a reconciliation between these two tables in these two exhibits.

Response:

The figures of $869,000 and $367,000 noted at line 14 of Schedule 5 should have been $126,000 and $169,108 which are presented in Tables 2-8 and 2-9.

10.
Reference: Exhibit 2 / 3 / 3 / p. 3

HHHI indicates that it is well underway toward completion of a formal Asset Management Plan.

When does HHHI expect to finalize its initial Asset Management Plan?

Response:

HHHI will continue to work on our Asset Management Plan through 2012. HHHI expects to implement the finalized Asset Management Plan early in 2013.

Gains and Losses on Retirements and Impairments

11.
Reference: Report of the Board *Transition to International Financial Reporting Standards* ("IFRS") July 28, 2009 [EB-2008-0408]

Under IFRS, asset retirement obligations include estimates of the cost of constructive obligations which was not required under CGAAP, and a revaluation of those obligations during the lives of the assets. HHHI did not present the accounting policy change on treatment of asset impairment.

The Board Report has stated as follows, at p 40:

> *Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The Board will assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement.*

At p. 19:

> *Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the Board.*

At p. 41:

> *Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates.*

a) Please confirm whether or not HHHI has any Asset Retirement Obligations ("ARO").

i. If yes, please identify and provide a detailed breakdown of the major asset components.

ii. If no, please provide a proposal for how the asset retirement obligations should be recovered in rates.

b) If HHHI has AROs, please confirm whether or not HHHI has identified the accounting change on AROs.

i. If so, please provide the accounting change and quantify the changes due to the adoption of IFRS for the test year and bridge year.

ii. If not, please provide the reasons and the plan when this is to be addressed.

c) For the AROs identified, please provide the depreciation expenses and accretion expenses and show how these expenses are currently included in the rate application.

d) Please confirm that HHHI has identified the gain or loss on the retirement of assets in a group of like assets. Please provide the treatment of the retirement for rate application purposes and disclose the amount. If the gains/losses are not charged to depreciation expense please state the reasons.

e) Please disclose any asset impairment loss recorded under IFRS which should be reclassified to PP&E. Please describe:

i. the nature of the losses;

ii. the amounts of the losses; and

iii. whether and how such amounts are to be reflected in rates.

Response:

a) HHHI does not have any known asset retirement obligations.

i. Not Applicable

ii. HHHI does not have any ARO included in the 2012 revenue requirement. In future, HHHI will seek recovery of any ARO in accordance with Board Guidelines.

b) Not applicable.

c) Not applicable.

d) Not applicable.

e) HHHI is not aware of any asset impairment loss under IFRS.

Service Reliability

12.

Reference: Exhibit 2 / 3 / 5 / pp. 2-3

The Reliability statistics in Table 2-28 for 2010 are identical, with and without consideration of loss of supply. However, Table 2-29 shows different statistics with consideration of the Hydro One system

> Please explain how these tables can be reconciled; in other words why is the second part of Table 2-28 not more similar to Table 2-29, given that the latter excludes incidents that appear to be a loss of service?

Response:

Please refer to HHHI Interrogatory Response to VECC question 2.

FIT and microFIT Renewable Generation

13.

Reference: Exhibit 2 / Appendix D 'HHHI's Green Energy Plan' / pp. 6-9

Table 3.1 on page 6 of the above-noted Reference provides a Table of microFIT generators connected to HHHI's distribution system with nominal output rating of each generator. Tables 3-2-2 and 3.3 on pages 7-9 show renewable generation projects that are in the queue under the OPA's FIT or microFIT programs but are not yet connected to HHHI's distribution system.

Board staff wishes to get an update on the approval status and an indication of the expected total kilowatt ("kW") output of the generators listed in Tables 3.1 and 3-2-2.

a) Please provide an update on the approval status of the microFIT and FIT projects listed in Tables 3.2.2 and 3.3 and any new applications that are in the queue.

b) Please provide an indication of the expected total kW output of the generators listed in Table 3.1.

c) Please provide an indication of the expected total kW output of the generators listed in Tables 3-2-2 and 3.3 and any new applications that are in the queue.

Response:

a) The updated status on the approval of the microFIT and FIT projects listed in Tables 3.2.2 and 3.3 and any new applications that are in the queue are presented in the updated tables below as Table OEB 1-3 and Table OEB 1-4 respectively.

Table OEB 1-3 : Revised MicroFIT Connections Status

Table 3-2-2, microFIT Generation in OPA Queue			
Distribution Feeder Circuit	**Municipal Address of Generator**	**Nominal Output Rating of Generator**	**Connected to Distribution System?**
1F1	9606 32nd Sideroad	10	Not Applied
1F3	13512 Fourth Line	7.2	Not Applied
1F3	13519 Fourth Line	10	Not Applied
1F3	13821 6th Line	10	Not Applied
3F1	14106 3rd Line	5.2	Not Applied
3F1	8 Commerce Cres	10	Applied for Offer to Connect[1]
3F2	15 Karen Drive	10	Not Applied
3F2	15 willoughby way	4	Not Applied
3F3	15132 Argyll Road	10	Not Applied
5F1	12 Morgan Drive	8.4	Applied for Offer to Connect[1]
5F1	15350 Argyll Road	6	Pending
5F1	179 Confederation St	5.5	Offer to Connect Issued[2]
5F1	7210 Hwy. 7	10	Applied for Offer to Connect[1]
5F1	7280 7 Hwy, RR3	9.89	Not Applied
5F2	196 Princess Anne Drive	10	Not Applied
5F2	2 Heslop Crt	10	Offer to Connect Issued[2]
5F2	20 Donaghedy Drive	9	Not Applied
5F2	21 Dawkins Cres	10	Not Applied
5F2	7 Worden View	9	Not Applied
5F3	224 mcdonald blvd.	10	Not Applied
7F1	64 Church St.	10	Not Applied
7F2	166 Mill Street W	10	Not Applied
7F2	6 Berry Street	10	Not Applied
9F1	121 Acton Blvd	10	Not Applied
9F2	44 Eastern Avenue	10	Not Applied
9F3	278 Mill St. E.	10	Not Applied
9F3	301 Queen Street East	10	Pending
9F3	35 lasby lane	10	Offer to Connect Issued[2]
9F3	75 Roseford Terrace	10	Not Applied
11F1	11974 22nd Sideroad	9.9	Offer to Connect Issued[2]
11F1	13016 L26 C 5 5th Line	10	Pending
11F1	13705 22nd Side Rd	9.2	Offer to Connect Issued[2]
11F2	10293-4th Line	9.6	Not Applied
11F2	15 Oak Ridge Drive	10	Not Applied
11F2	31 Logan Court	10	Not Applied
11F2	333 Queen Street East	9	Pending
11F2	43 Munro Circle	10	Pending
11F2	8482 6th Line	10	Not Applied
11F3	105 Acton Blvd	10	Not Applied
11F3	12562 9th Line North	10	Pending
11f3	16632 Leslie Hill	10	Not Applied
11F3	36 Costigan Court	2.3	On Hold
11F3	39 Costigan Court	7	Offer to Connect Issued
11F3	73 Barraclough Blvd.	5	Not Applied
13F2	20 Moore Park Cres.	4.3	Offer to Connect Issued[2]
15F2	10741 Third Line	10	Not Applied
15F2	18 Credit St.	10	Not Applied
15F2	39 Harley Avenue	9	Offer to Connect Issued[2]
15F2	4 Allison Court	10	Not Applied
15F2	40 Confederation	10	Offer to Connect Issued[2]

Table OEB 1-3 : Revised MicroFIT Connections Status (cont'd)

15F2	42 Cameron Street	6.58	Not Applied
15F2	84 Confederation St.	10	Offer to Connect Issued[2]
15F2	86 River Rd.	10	Not Applied
15F3	42 Gooderham Dr	10	Offer to Connect Issued[2]
17F1	43 Alice Street	10	Not Applied
17F3	35 Marilyn Crescent	10	Not Applied
17F3	53 Hewson Crescent	8	Not Applied
19F2	1 Wilson Court	5	Not Applied
19F2	11749 22nd Sideroad	5.98	Not Applied
19F2	11760 7 Hwy	10	Not Applied
23F1	10783 6th line	9.95	Not Applied
23F1	10815 third line	10	Not Applied
23F1	10829 5TH LINE	10	Not Applied
23F1	11062 5th Line	9.975	Not Applied
23F1	11998 L20 C 1E Dublin Line	10	Not Applied
23F1	3 Deer Run Crescent	10	Offer to Connect Issued[2]
23F1	54 Arborglen Drive	10	Offer to Connect Issued[2]
23F1	59 Cobblehill Road	6	Not Applied
23F1	6 Bishop Crt	10	Not Applied
23F1	72 McNally Street	10	Not Applied
23F1	7419 Side Road 15	10	Offer to Connect Issued[2]
23F1	77 Market Street	10	On Hold
23F1	8277 10 Side Road	10	Not Applied
23F2	10739 15th Side Rd	10	On Hold
23F3	8390 Hornby Rd	10	Not Applied
41M21	13417 22 Side Rd	10	Applied for Offer to Connect[1]
41M21	13536 15 Side Road	10	Pending
41M21	13931 Cromar Ct	10	Offer to Connect Issued[2]
41M21	22 Harriet Streeet	10	Not Applied
41M21	55 Craig Crescent	7	Not Applied
41M21	82 Craig Cres	10	Pending
41M21	84 Smith Drive	10	Not Applied
41M21	8602 Winston Churchill Blvd	10	Not Applied
41M21	88 Miller Drive	9	Not Applied
41M21	8851 6th Line Road	10	Not Applied
41M21	8958 Trafalgar Road	10	Offer to Connect Issued[2]
41M21	9328 15th Sideroad	10	Not Applied
41M21	96 Poplar Ave.	10	Not Applied
41M21	98 FORSYTH CRES	7	Applied for Offer to Connect[1]
41M21	98 Main St. N	10	Not Applied
	5193 5th Line RR2	10	Not in HHH Area
41M29	9017 5th Side Road	10	Not Applied
41M29	9422 REGIONAL RD #25	10	Not Applied
41M30	12688 4th line	10	Not Applied
42M21	RR#4 11682 Hwy 25	7	Not Applied
	Expected nameplate rating output	870.975	kW

for the OPA to change the applicants application status to "Pending LDC Offer to Connect".

Connect", HHH has assessed capacity, determined capacity exists, and issued an Offer to Connect.

Table OEB 1-4: Revised FIT Connections Status

Table 3-3, FIT Generation in OPA Queue			
Distribution Feeder Circuit	**Municipal Address of Generator**	**Nominal Output Rating of Generator**	**Connected to Distribution System?**
15F1	30 Armstrong Avenue	250	Applied - Pre. CIA Phase
42M25	171 Guelph Street	375	Not Applied
41M21	8889 10th Line	250	Not Applied
	Expected nameplate rating output	875	kW

b) The expected total kW output of the generators listed is presented in the Table OEB 1-5 below.

Table OEB 1-5 : Expected Total kW Output of Generators

Updated Table 3.1 Connected and Active microFIT Generators

Distribution Circuit Feeder	Municipal Address of Generator	Nominal Output Rating of Generator	Date of Interconnection
1F3	14011 Trafalgar Road	7.2	24-Oct-11
5F1	3 Morgan Drive	10	17-Aug-10
5F1	4 Morgan Drive	10	30-May-11
5F1	8 Morgan Drive	10	22-Dec-11
5F1	9 Morgan Drive	5	26-May-10
5F1	14191 Crewsons Line	10	1-Dec-10
5F2	13066 Dublin Line	10	26-May-10
5F2	16321 6th Line, Limehouse	10	21-Dec-10
5F2	12976 Silvercreek Dirve	9.73	24-Oct-11
5-F2	181 Churchill Road South, Acton	5.4	10-Aug-11
7F1	36 Vimy Street	10	27-Jan-11
7F1	13 John Street South, Acton	10	2-Sep-11
9F3	13895 Churchill Road	10	22-Dec-10
11F1	11632 22nd Side Road	9.5	26-Aug-10
11F1	12849 5th Line	9.88	20-May-11
11F1	12909 5th Line	9.5	16-Dec-10
11F1	13111 5th Line	10	14-Oct-10
11F2	12249 8th Line	10	13-Jul-10
11F2	13010 22nd Side Road	10	26-Jul-11
11F2	41 Munro Circle	8.36	13-Jun-11
11F3	22 Bishop Court	10	3-Jun-11
11F3	14249 10th Line	9.88	25-Jul-11
15F1	48 Harding Street	3.61	8-Apr-11
15F2	7 Karen Drive	3.456	28-Jul-10
15F2	28 Logan Court	6.72	11-Apr-11
15F3	54 Hewson Cres.	5.6	8-Dec-10
17F3	9 Sherman Court	9.88	25-Oct-11
19F2	38 Chelvin Drive	3.42	4-May-11
19F2	17 Rosefield Drive	5.13	21-Jun-11
21-F1	8684 9th Line	10	1-Feb-11
23F1	7400 15 SDRD	10	5-Aug-10
23F1	9313 4th Line, RR5, Milton	9.88	15-Aug-11
23F2	11348 Trafalgar Road	8	14-Dec-10
23-F2	9365 10th Side Road	10	1-Feb-11
3-F1	40 Dairy Drive, Acton	8.6	17-Oct-11
41M21	10 Lookout Court	3.8	5-Aug-10
41M21	62 Grist Mill Drive	10	12-Jul-10
41M21	76 North Ridge Cres., Georgetown	5	31-Aug-11
41M21	9 May Street, Georgetown	2.28	19-Aug-11
41M21	63 Garrison Square	10	7-Sep-11
41M29	9722 3rd Line	10	9-Aug-10
42M25	161 Guelph Street	10	22-Dec-10
	microFIT Nameplate Rating in kW:	**349.826**	

Table 3.1.2 Connected and Active FIT Generators (New table)

Distribution Circuit Feeder	Municipal Address of Generator	Nominal Output Rating of Generator	Date of Interconnection
15F1	24 Armstrong Ave.	248	21-Jul-11
42M28	114 Armstrong Ave.	248	2-Sep-11
	FIT Nameplate Rating in kW:	**496**	

c) Please refer to the tables presented in part a) above.

HHHI's Renewable Generation Initiative

14.
References: Exhibit. 2 / Appendix D HHHI's Green Energy Plan' p. 9; Exhibit 2 / 3 / 7

HHHI indicates in its GEA Plan that in 2010 it undertook a pilot project to install pole-mounted solar photovoltaic panels at selected sites throughout its service territory.
In Exhibit 2 / 3 / 7 HHHI describes the Green Energy Initiative to install solar panels on 1400 utility poles in 2012 at a capital cost of $1.4 million proposed for inclusion in the rate base. Each installation includes a 220 - 280 watt solar panel, a Smart Energy Module with an inverter, two way wireless Smart Grid communicator, sensors, digital meter, and a pole mounting system to attach to existing utility poles. Based on the estimated total capital cost of $1.4 million, this works out to an average of $1000 per pole.

a) Please provide the results of any analysis carried out by HHHI with respect to its 2010 pilot project to install pole-mounted solar photovoltaic panels including costs, benefits, cost/benefit analysis etc.

b) Does the estimated average cost of $1000 per pole for the proposed 2012 solar panel initiative include all costs, e.g. materials, labour, engineering, commissioning, inspections etc? Please provide a breakdown of costs and explanation.

c) Is it HHHI's intention to implement the pole-mounted solar panel project within the context of other HHHI capital and operating programs?

d) What is HHHI's rationale for not considering the pole-mounted solar panel project as a capital project under the HHHI's Green Energy Plan?

Response:

a) HHHI has tested four units for the past year on poles in HHHI's service territory. These four units have operated and 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. The units produce electricity directly to the secondary system during the peak hours during the day – producing power directly where it is consumed.

HHHI believes the benefits include line loss reduction and secondary voltage monitoring. A larger project will enable us to quantify those benefits. Further, any power production, line loss and transmission savings will be directly passed into the customer through our Deferral and Variance accounts. The qualitative benefits to the community are a highly visible renewable energy project by the utility and furthering the commitment to the Green Plan of the Municipality.

b) Yes, the budget of $1,000 includes all costs.

The units are commissioned immediately upon deployment producing electricity immediately to the secondary grid. The pole mounted solar system is comprised of a Smart Energy Module, (inverter, meter and communications), a 220 watt panel, a communicator, and a supporting rack structure for mounting onto utility poles.

c) Yes, it is HHHI's intention to implement the pole mounted solar panel project within the context of HHHI's capital.

d) HHHI did consider the project as part of the Green Energy Plan section 3.3 and at the time of writing the Green Energy Plan the full project had not been completely budgeted.

Challenges Associated with Distributed Generation

15.
Reference: Exhibit. 2 / Appendix D / pp. 10-14

HHHI describes in this reference the various "challenges" associated with connecting distributed generation to HHHI's distribution system including: impact on special protections, short circuit issues, protection coordination, impact on faulted circuit indicators and issues with shared transformer stations. These are

presented as potential issues with no specific solutions, expected costs or a plan to address the issues.

What plan(s), if any, does HHHI have for addressing the potential issues described in the above-noted Reference in 2012 and beyond? Please provide details on scope, schedule, priority and costs.

Response:

For the feeder protection upgrades (described in Exhibit.2/Appendix D/pp. 10-14), HHHI is undertaking this project as part of the 2012 Capital.

For the feeder expansions, described in Exhibit 2/Appendix D/pp. 16-17, HHHI does not need to undertake such an enhancement for any of the renewable generation projects of which the organization is aware. At such time as this work may be necessary, and the costs to HHHI are deemed "material", HHHI will advise the Ontario Energy Board via an amendment to HHHI'S Green Energy Plan.

For the transformer station design provisions, described in Exhibit 2/Appendix D / on pg 17, the incremental cost (if any) will be built into the overall cost of the station.

Distribution System Enhancements for Smart Grid Development

16.
Reference: Exhibit. 2 / Appendix D / pp. 15 - 17

HHHI describes in this reference some proposed enhancements that would contribute to the Ontario government's smart grid objectives including modifications to feeder protections, extending three-phase circuitry into rural areas and consideration of distributed generation connections in the design of new transformer stations.

HHHI states that the estimated cost for the feeder protection changes is about $15,000 per feeder. It also states that, as instances arise, HHHI will extend the three-phase aerial circuitry based on a cost sharing arrangement with the generator, in accordance with the Transmission System Code. Based on that, HHHI bears the initial $90,000 per nameplate MW output of investment cost, with the balance borne by the generator.

a) Is HHHI planning to carry out the feeder protection changes on all its feeders or as needed to accommodate new generator connections? Please explain.

b) Please provide an estimate of the cost HHHI expects to incur and the timeframe for the feeder protection changes.

c) Please provide an estimate of the cost HHHI expects to incur and the timeframe for extending three-phase circuitry into rural areas.

d) Please explain HHHI's rationale for categorizing the above-noted enhancements as Smart Grid development and identify information on the Smart Grid technologies that are utilized.

e) If the estimated costs for the above-noted enhancements are not entirely Smart Grid related, please provide a breakdown that indicates the portion that is Smart Grid related and the portion that is related to connection of renewable generation.

Response:

a) HHHI has a long term project underway to modernize the feeder protections in its substations – every year or so, the feeder protections are modernized for 2 or 3 feeders. If a FIT project were to emerge on a feeder where the protections haven't yet been modernized, HHHI would simply adjust the order that we tackle the outstanding feeder protections. To reiterate, HHHI plans to modernize all vintage feeder protections anyway, so doesn't consider the possible re-ordering of work to be a special cost that should be borne by a Green Energy rate rider.

b) Expected cost for the feeder protection changes can be found in Exhibit 2 / Appendix D / pp. 16 (HHHI'S Green Energy Plan).

c) See response to question 15 above for costs. It will be several years to fully extend the three-phase circuitry into the rural areas.

d) The definition of Smart Grid in Ontario (Ontario Bill 150, Green Energy Act, 2009) specifically, Schedule B, clause 1, subsection (5) reads as follows:

> *Smart grid*
>
> *(1.3) For the purposes of this Act, the smart grid means the advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of,*
>
> *(a) enabling the increased use of renewable energy sources and technology, including generation facilities connected to the distribution system;*
>
> *(b) expanding opportunities to provide demand response, price information and load control to electricity customers;*
>
> *(c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications; or*
>
> *(d) supporting other objectives that may be prescribed by regulation.*

In short, anything done to the electrical distribution system to promote the connection of renewable energy systems, or to support energy efficiency or load management control will qualify for smart grid.

HHHI'S Green Energy Plan identifies a number of distribution system enhancements that could be classified as both Smart Grid expenditures and normal asset management expenditures. HHHI has chosen to treat the modernization of feeder protections as a normal asset sustainment activity (paid for by the distribution tariff) and line extensions, if any are ever required, solely to support large-scale FIT projects as a Green Energy activity (paid for in accordance with the cited provisions of the Distribution System Code and a Green Energy rate rider).

e) Not applicable.

Cost Recovery of Green Energy Plan Costs

17.
Reference: Exhibit. 2 / Appendix D / p. 19

HHHI states in this reference that it is not seeking to recover costs related to the connection of renewable generation in the form of a short term rate rider at this time.

Please explain why HHHI has chosen not to seek cost recovery of Green Energy Act Plan costs at this time.

Response:

See response to questions 15 and 16 above – HHHI considers the modernization of our feeder protections to be a normal asset sustainment activity.

Other Distribution Revenue

18.
References: Exhibit 3 / 3 / 1; Exhibit 4 / 1 / 1 / p. 13; Exhibit 4 / 2 / 4 / p. 2-3

a) Please confirm that the revenue shown in Table 3-23 account 4375 is the same as the inter-affiliate revenue derived in Table 4-14.

b) Please identify any allocation factors in Exhibit 4 / 2 / 4 / p. 2-3 that might vary substantially from year to year. If most of the allocators are stable, please explain why the forecast of account 4375 remains stable at $396,000 at the 2011 level, rather than increasing with OM&A costs (e.g. at 31.5% per Table 4-6).

c) Is revenue from microFIT generators included in one of the accounts in Table 3-23? If so, in which account is it included and how much revenue is gained?

Response:

a) Confirmed.

b) None of the allocation factors in Exhibit 4 / 2 / 4 / p. 2-3 vary substantially from year to year to warrant an increase in the inter-affiliate revenues The increase in OM&A costs as shown in table 4 – 6 is affected mainly by the items listed below. None of which significantly affects the costs of services provided to affiliates.

- Increase in OM&A as a result of transitioning to MIFRS
- Inclusion of smart costs in OM&A in 2012
- Increase in tree trimming costs and
- Increase in FTE's as a result of succession planning.

c) The revenue from microFIT generators in not included in Table 3-23. It was not included anywhere as the amount is insignificant. The amount billed from Jan to Sept. 2011 is – $988.

Operation Maintenance and Administration

19.
References: Exhibit 4 / 1 / 1; Exhibit 4 / 2 / 1 / p. 5

In Tab 1, Tables 4-2, 4-3, 4-4, 4-5 and 4-6, HHHI provide the following with respect to Meter Reading Expenses (Account 5310):

Year	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Meter Reading Expense	$147,000	$134,104	$134,696	$131,177	$16,300	$206,840

On page 5 of Exhibit 4 / 2 /1, HHHI states:

Meter reading services have, historically, been contracted out to a non-affiliated third party under a service contract agreement. Effective June 1, 2011 HHHI started billing Residential and General Service less than 50 kW customers on a Time-of-Use basis using smart meters.

a) Please confirm that the costs of the third party contract were recorded in account 5310 as shown in the above table.

b) Please explain the decrease in meter reading expenses in 2011 of $16,300 compared to approximately $135,000 per annum from 2008 to 2010.

c) Please explain the forecasted increase in Meter Reading Expenses for 2012, relative to:

i. 2011; and
ii. the historical norm of approximately $135,000 per annum.

Response:

a) The costs of the third party contract were recorded in account 5310 from 2008 Board Approved to 2010. For 2011 and 2012 the amounts of $90,000 and $25,000 respectively for third party costs were included in account 5315. For 2012, HHHI excluded $65,000 of third party costs which is for none are hydro related services.

b) Please refer to response to part a).

c)

i) The increase in 2012 compare to 2011 is a result of the increase in smart metering costs of $190,300 that is included in 5310. (E.g. smart meter entity fees of $135,000, smart meter WAN monthly fee of $15,000, TOU Portal Maintenance fee of $16,000);

ii) If you subtract the $190,300 smart meter related cost and add the $65,000 third party costs that was excluded in the 2012, the balance of $81,540 ($206, 840 – $190,300 + $65,000) is lower that the historical norm of $135,000.

20.
Reference: Exhibit 4 / 2 / 3 / p. 7

The increased cost of Billing and Collecting is due in part to "the addition of a Billing Clerk for succession planning purposes".

a) Please provide information on the expected length of time that there will be an overlap of the incumbent and the proposed new clerk, during the test year, and if applicable beyond the test year.

b) Assuming that the overlap is considerably less than the period of the IRM adjustments following this cost-of-service application, has HHHI considered applying an adjustment factor to the increase requested for the test year revenue requirement?

Response:

a) The expected length of time that there will be an overlap of the incumbent and the proposed new clerk, during the test year, and beyond the test year is one and a half years.

b) The overlap is less than the period of the IRM adjustments following this cost-of-service application. HHHI did not apply an adjustment factor to the increase requested for the test year revenue requirement. There are other positions in the organization that will overlap in the test year and the IRM period that HHHI did not include in the test year revenue requirement.

Specifically, an accounting clerk will retire at the end of 2012 and the payroll clerk will retire in two years. The costs relating to the overlap for none of these positions have been included in the test year.

21.
Reference: Exhibit 4 / 2 / 3 / pp. 6-7

a) Please provide further explanation of the $76,000 identified for "smart meter communication costs" as a driver for the increase of $297,106 for Account 5315 – Customer Billings.
b) Is this a recurring cost, or one-time cost in 2012 only?

Response:

a) The $76,000 included in account 5315 – Customer Billings for communication costs is the costs of communicating and reaching out to customers (see response to IR 22 for breakdown of costs).

b) It is a recurring cost.

22.

Reference: Exhibit 4 / 2 / 3 / p. 7

The increased cost of Billing and Collecting includes $76,000 in Smart Meter communication costs.

a) Please provide a description and breakdown of these costs.

b) Are there any labour or other costs that will be reduced, immediately or in the foreseeable future, that would tend to offset this increased communication cost.

Response:

a) The description and breakdown of these costs are provided in Table OEB 1-6 below.

Table OEB 1-6 : Increased Billing and Collection Cost Breakdown

Description		Amount
Newspaper ads		3,750.00
Bill inserts		24,648.00
TOU brochures		41,080.00
Town Hall Meetings		5,100.00
Community events		1,422.00
Total		**76,000.00**

b) There are no labour or other costs that HHHI can reduce immediately or in the foreseeable future, to offset this increased communication cost.

23.

References: Letter of the Board 'Use of Modified IFRS as a Basis for Filing Cost of Service Applications for 2012 Rates', March 15, 2011; Exhibit 4 / 1 / 1 / p. 1

HHHI stated in Exhibit 4 / 1 / 1, at p. 1:

> *The operating costs presented in this Exhibit represent the annual expenditures required to sustain HHHI's distribution operations. HHHI follows the Board's Accounting Procedures Handbook (the "APH") in distinguishing between operations and maintenance work. A summary of HHHI's operating costs for 2008 Board Approved, 2008 Actual, 2009 Actual, 2010 Actual, 2011 Bridge Year and the 2012 Test Year and the variances year over year, in accordance with the Filing Requirements, is presented below. HHHI has provided the required 2008 Board Approved to 2010 Actual based on CGAAP and 2011 Bridge Year and 2012 Test Year based on Modified IFRS.*

In the March 2011 letter the Board provided a revised version of paragraph 9.1.2 of the Board Report:

> *Electricity distributors filing cost of service applications for rates for 2012 should make all reasonable efforts to provide the forecasts for the 2012 test year (and any other subsequent test years) in modified IFRS accounting format. In addition, the electricity distributor must provide the required actual years, the bridge year and the forecasts for the test year(s) in CGAAP-based format. Further, the electricity distributor must identify financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting. A distributor for whom the filing of the forecasts for the 2012 test year in modified IFRS is an unreasonable burden and that files under CGAAP must include in its rate application an explanation of the reason for filing under CGAAP and a plan for the transition to modified IFRS accounting as a basis for setting its rates.*

HHHI did not provide the bridge year and test years forecasts in CGAAP based format, as required by the Board.

a) Please provide all applicable schedules, e.g., operating costs, etc. for the bridge year and tests year under CGAAP similar to the ones reported under an IFRS regime

b) Please identify the financial differences and resulting revenue requirement impacts arising from the adoption of modified IFRS accounting.

Response:

a) Please see Tables OEB 1-7, OEB 1-8, OEB 1-9 and OEB 1-10.

Table OEB 1-7 : Summary of OM&A Expenses (CGAAP)

Appendix 2-E
Summary of OM&A Expenses

	LRY	2008	Variance	Percentage Change
	Board-approved	Actuals	$	%
Operations	$ -	$ 695,529	$ 695,529	
Maintenance	$ -	$ 751,353	$ 751,353	
Billing and Collecting	$ -	$ 1,012,516	$ 1,012,516	
Community Relations	$ -	$ -	$ -	
Administrative and General	$ -	$ 2,615,659	$ 2,615,659	
Total OM&A Expenses	$ -	$ 5,075,057	$ 5,075,057	
Inflation Rate				

	2008	2009	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 695,529	$ 819,741	$ 124,212	17.86%
Maintenance	$ 751,353	$ 173,136	-$ 578,217	-76.96%
Billing and Collecting	$ 1,012,516	$ 1,091,868	$ 79,352	7.84%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,615,659	$ 2,341,417	-$ 274,242	-10.48%
Total OM&A Expenses	$ 5,075,057	$ 4,426,162	-$ 648,895	-12.79%
Inflation Rate				

	2009	2010	Variance	Percentage Change
	Actuals	Actuals	$	%
Operations	$ 819,741	$ 892,155	$ 72,414	8.83%
Maintenance	$ 173,136	$ 275,319	$ 102,183	59.02%
Billing and Collecting	$ 1,091,868	$ 1,111,430	$ 19,562	1.79%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,341,417	$ 2,100,978	-$ 240,439	-10.27%
Total OM&A Expenses	$ 4,426,162	$ 4,379,882	-$ 46,280	-1.05%
Inflation Rate				

Table OEB 1-7 : Summary of OM&A Expenses (CGAAP) (cont'd)

Appendix 2-E
Summary of OM&A Expenses

	2010 Actuals	2011 Bridge Year	Variance $	Percentage Change %
Operations	$ 892,155	$ 536,089	-$ 356,066	-39.91%
Maintenance	$ 275,319	$ 360,051	$ 84,731	30.78%
Billing and Collecting	$ 1,111,430	$ 1,197,615	$ 86,185	7.75%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,100,978	$ 2,456,346	$ 355,368	16.91%
Total OM&A Expenses	$ 4,379,882	$ 4,550,101	$ 170,219	3.89%
Inflation Rate				

	2011 Actuals	Test Year Forecast	Variance $	Percentage Change %
Operations	$ 536,089	$ 966,705	$ 430,617	80.33%
Maintenance	$ 360,051	$ 665,999	$ 305,948	84.97%
Billing and Collecting	$ 1,197,615	$ 1,683,690	$ 486,074	40.59%
Community Relations	$ -	$ -	$ -	
Administrative and General	$ 2,456,346	$ 2,687,646	$ 231,300	9.42%
Total OM&A Expenses	$ 4,550,101	$ 6,004,040	$ 1,453,939	31.95%
Inflation Rate				

	Test Year Actuals	Test Year Forecast	Variance $	Percentage Change %
Operations	$ 966,705		-$ 966,705	-100.00%
Maintenance	$ 665,999		-$ 665,999	-100.00%
Billing and Collecting	$ 1,683,690		-$ 1,683,690	-100.00%
Community Relations	$ -		$ -	
Administrative and General	$ 2,687,646		-$ 2,687,646	-100.00%
Total OM&A Expenses	$ 6,004,040	$ -	-$ 6,004,040	-100.00%
Inflation Rate				

Table 2: Additional Total OM&A Expense Comparative Information Table

Required Total OM&A Comparison

	2011 Actuals	Test Year Forecast	Variance $	Percentage Change %
Test Year versus Most Current Actuals	$ 4,550,101	$ -	-$ 4,550,101	-100.00%
	LRY Board-approved	Test Year Forecast	Variance $	Percentage Change %
Test Year versus LRY Board-approved	$ -	$ 6,004,040	$ 6,004,040	
Simple average of % variance for all years				-15.60%
Compound annual growth rate for all years				0

Table OEB 1-8 : Detailed OM&A Expenses (CGAAP)

Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account	Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	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 - Operations		$ 695,529	$ 819,741	$ 892,155	$ 536,089	$ 966,705
Account	**Description**	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
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 - Maintenance		$ 751,353	$ 173,136	$ 275,319	$ 360,051	$ 665,999

Table OEB 1-8 : Detailed OM&A Expenses (CGAAP) (cont'd)

Appendix 2-F
Detailed, Account by Account, OM&A Expense Table
(excluding Depreciation and Amortization)

Account Description	2008 Actual	2009 Actual	2010 Actual	Bridge Year	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	$ 1,012,516	$ 1,091,868	$ 1,111,430	$ 1,197,615	$ 1,683,690
Account Description	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
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	$ 6,864	$ 2,032	$ -	$ -	$ -
Account Description	**2008 Actual**	**2009 Actual**	**2010 Actual**	**Bridge Year**	**Test Year**
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	$ 5,111,058	$ 4,436,426	$ 4,386,371	$ 4,580,101	$ 6,034,040

Table OEB 1-9 : 2011 Fixed Asset Continuity Schedule (CGAAP)

Appendix 2-B
Fixed Asset Continuity Schedule - CGAAP

2011

CCA Class	OEB	Description	Depreciation Rate	Cost				Accumulated Depreciation				Net Book Value
				Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
N/A	1805	Land		$ 359,609	$ -	$ -	$ 359,609	$ -	$ -	$ -	$ -	$ 359,609
47	1808	Buildings		$ 3,080,205	$ -	$ -	$ 3,080,205	-$ 598,689	-$ 123,208	$ -	-$ 721,897	$ 2,358,309
13	1810	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,223,477	$ 111,529	$ -	$ 4,335,006	-$ 1,053,166	-$ 171,170	$ -	-$ 1,224,336	$ 3,110,670
47	1825	Storage Battery Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 15,977,374	$ 1,413,682	$ -	$ 17,391,056	-$ 12,306,771	-$ 667,369	$ -	-$ 12,974,139	$ 4,416,917
47	1835	Overhead Conductors & Devices		$ 5,607,599	$ 1,753,243	$ -	$ 7,360,842	-$ 357,649	-$ 259,369	$ -	-$ 617,017	$ 6,743,825
47	1840	Underground Conduit		$ 970,085	$ 410,570	$ -	$ 1,380,654	-$ 78,395	-$ 47,015	$ -	-$ 125,410	$ 1,255,244
47	1845	Underground Conductors & Devices		$ 4,675,723	$ 384,202	$ -	$ 5,059,925	-$ 226,091	-$ 194,713	$ -	-$ 420,804	$ 4,639,121
47	1850	Line Transformers		$ 6,961,088	$ 277,660	$ -	$ 7,238,748	-$ 327,424	-$ 283,997	$ -	-$ 611,421	$ 6,627,327
47	1855	Services (Overhead & Underground)		$ 2,556,444	$ 193,736	$ -	$ 2,750,180	-$ 418,500	-$ 106,132	$ -	-$ 524,633	$ 2,225,548
47	1860	Meters		$ 1,048,410	$ -	$ -	$ 1,048,410	-$ 19,920	-$ 41,936	$ -	-$ 61,856	$ 986,554
47	1860	Meters (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CEC	1906	Land Rights		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1908	Buildings & Fixtures		$ -	$ 146,075	$ -	$ 146,075	$ -	-$ 2,922	$ -	-$ 2,922	$ 143,154
13	1910	Leasehold Improvements		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ 351,062	$ 61,720	$ -	$ 412,782	-$ 256,806	-$ 76,384	$ -	-$ 333,191	$ 79,592
10	1920	Computer Equipment - Hardware		$ 1,033,364	$ 39,000	$ -	$ 1,072,364	-$ 967,411	-$ 210,573	$ -	-$ 1,177,984	-$ 105,620
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -		$ -	$ -	$ -		$ -	$ -	$ -
12	1925	Computer Software		$ 1,062,621	$ 172,060	$ -	$ 1,234,681	-$ 1,032,946	-$ 382,884	$ -	-$ 1,415,829	-$ 181,149
10	1930	Transportation Equipment		$ 2,291,028	$ 228,000	$ -	$ 2,519,028	-$ 1,321,349	-$ 300,629	$ -	-$ 1,621,977	$ 897,051
8	1935	Stores Equipment		$ 53,152	$ 33,320	$ -	$ 86,472	-$ 52,043	-$ 6,981	$ -	-$ 59,024	$ 27,448
8	1940	Tools, Shop & Garage Equipment		$ 558,091	$ -	$ -	$ 558,091	-$ 354,902	-$ 55,809	$ -	-$ 410,711	$ 147,381
8	1945	Measurement & Testing Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment		$ -	$ 80,755	$ -	$ 80,755	$ -	$ -	$ -	$ -	$ 80,755
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises		$ 563,902	$ -	$ -	$ 563,902	-$ 298,141	-$ 56,390	$ -	-$ 354,531	$ 209,371
47	1980	System Supervisor Equipment		$ 833,241	$ 53,252	$ -	$ 886,494	-$ 363,824	-$ 57,324	$ -	-$ 421,149	$ 465,345
47	1985	Miscellaneous Fixed Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants		-$ 5,912,892	-$ 591,281	$ -	-$ 6,504,174	$ 1,022,032	$ 248,341	$ -	$ 1,270,373	-$ 5,233,800
	etc.			$ -		$ -	$ -	$ -		$ -	$ -	$ -
				$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -
		Total		**$ 46,293,583**	**$ 4,767,523**	**$ -**	**$ 51,061,106**	**-$ 19,011,994**	**-$ 2,796,463**	**$ -**	**-$ 21,808,457**	**$ 29,252,649**
				-$ 0								

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation

Transportation	-$ 300,629
Stores Equipment	
Net Depreciation	-$ 2,495,835

Table OEB 1-10 : 2012 Fixed Asset Continuity Schedule (CGAAP)

Appendix 2-B
Fixed Asset Continuity Schedule - CGAAP

2012

CCA Class	OEB	Description	Depreciation Rate	Cost				Accumulated Depreciation				Net Book Value
				Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	
N/A	1805	Land		$ 359,609			$ 359,609	$ -	$ -		$ -	$ 359,609
47	1808	Buildings		$ 3,080,205			$ 3,080,205	-$ 721,897	-$ 123,208		-$ 845,105	$ 2,235,100
13	1810	Leasehold Improvements		$ -			$ -	$ -	$ -		$ -	$ -
47	1815	Transformer Station Equipment >50 kV		$ -			$ -	$ -	$ -		$ -	$ -
47	1820	Distribution Station Equipment <50 kV		$ 4,335,006	$ 34,861		$ 4,369,867	-$ 1,224,336	-$ 174,097		-$ 1,398,433	$ 2,971,434
47	1825	Storage Battery Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1830	Poles, Towers & Fixtures		$ 17,391,056	$ 4,057,518		$ 21,448,574	-$ 12,974,139	-$ 783,799		-$ 13,757,938	$ 7,690,636
47	1835	Overhead Conductors & Devices		$ 7,360,842	$ 2,504,129		$ 9,864,971	-$ 617,017	-$ 344,516		-$ 961,534	$ 8,903,437
47	1840	Underground Conduit		$ 1,380,654	$ 493,240		$ 1,873,894	-$ 125,410	-$ 65,091		-$ 190,501	$ 1,683,393
47	1845	Underground Conductors & Devices		$ 5,059,925	$ 413,691		$ 5,473,616	-$ 420,804	-$ 210,671		-$ 631,475	$ 4,842,141
47	1850	Line Transformers		$ 7,238,748	$ 528,576		$ 7,767,324	-$ 611,421	-$ 300,121		-$ 911,542	$ 6,855,781
47	1855	Services (Overhead & Underground)		$ 2,750,180	$ -		$ 2,750,180	-$ 524,633	-$ 110,007		-$ 634,640	$ 2,115,540
47	1860	Meters		$ 1,048,410	$ -		$ 1,048,410	-$ 61,856	-$ 41,936		-$ 103,792	$ 944,617
47	1860	Meters (Smart Meters)		$ 3,768,873	$ -		$ 3,768,873	-$ 501,430	-$ 251,625		-$ 753,055	$ 3,015,818
N/A	1905	Land		$ -	$ -		$ -	$ -	$ -		$ -	$ -
CEC	1906	Land Rights		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1908	Buildings & Fixtures		$ 146,075	$ 10,000		$ 156,075	-$ 2,922	-$ 6,043		-$ 8,965	$ 147,111
13	1910	Leasehold Improvements		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1915	Office Furniture & Equipment (10 years)		$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (5 years)		$ 412,782	$ 300		$ 413,082	-$ 333,191	-$ 82,586		-$ 415,777	-$ 2,695
10	1920	Computer Equipment - Hardware		$ 1,072,364	$ 213,224		$ 1,285,588	-$ 1,177,984	-$ 235,795		-$ 1,413,780	-$ 128,191
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -			$ -	$ -			$ -	$ -
12	1925	Computer Software		$ 1,234,681	$ 363,000		$ 1,597,681	-$ 1,415,829	-$ 283,236		-$ 1,699,065	-$ 101,385
10	1930	Transportation Equipment		$ 2,519,028	$ 230,000		$ 2,749,028	-$ 1,621,977	-$ 329,254		-$ 1,951,231	$ 797,797
8	1935	Stores Equipment		$ 86,472	$ -		$ 86,472	-$ 59,024	-$ 8,647		-$ 67,672	$ 18,800
8	1940	Tools, Shop & Garage Equipment		$ 558,091	$ 43,170		$ 601,261	-$ 410,711	-$ 57,968		-$ 468,678	$ 132,583
8	1945	Measurement & Testing Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1950	Power Operated Equipment		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1955	Communications Equipment		$ 80,755	$ -		$ 80,755	$ -	$ -		$ -	$ 80,755
8	1955	Communication Equipment (Smart Meters)		$ -	$ -		$ -	$ -	$ -		$ -	$ -
8	1960	Miscellaneous Equipment		$ -	$ -		$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises		$ 563,902	$ -		$ 563,902	-$ 354,531	-$ 56,390		-$ 410,921	$ 152,981
47	1980	System Supervisor Equipment		$ 886,494	$ 53,252		$ 939,746	-$ 421,149	-$ 60,875		-$ 482,023	$ 457,722
47	1985	Miscellaneous Fixed Assets		$ -	$ -		$ -	$ -	$ -		$ -	$ -
47	1995	Contributions & Grants		-$ 6,504,174	-$ 1,396,208		-$ 7,900,382	$ 1,270,373	$ 288,091		$ 1,558,464	-$ 6,341,917
	etc.			$ -			$ -	$ -			$ -	$ -
								$ -			$ -	$ -
		Total		**$ 54,829,979**	**$ 7,548,752**	**$ -**	**$ 62,378,731**	**-$ 22,309,887**	**-$ 3,237,776**	**$ -**	**-$ 25,547,663**	**$ 36,831,068**

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation
Transportation -$ 329,254
Stores Equipment
Net Depreciation -$ 2,908,522

b) Please refer to HHHI interrogatory response to Energy Probe question 6.

24.

References: Report of the Board *'Transition to International Financial Reporting Standards'* ("IFRS") July 28, 2009 [EB-2008-0408]; Exhibit 4 / 2 / 7 / p. 1

HHHI stated:

> *HHHI uses the pooling of assets for all fixed assets with the exception of Computer Equipment/Software, Automotive Equipment, Furniture & Equipment, Communication Equipment, and Capital Tools.*

Useful lives for PP&E are to be reviewed at least at each financial year-end with MIFRS.

The Board's policy articulates that LDCs shall use the Board sponsored Kinectrics study or sponsor their own study to justify changes in useful lives. The typical useful lives

(TUL) from the Kinectrics report is the recommended Reference point. The Board will no longer prescribe service lives for PP&E.

Salient points from the Board Report are as follows, at p. 21:

> *The Board will facilitate a joint depreciation study for electrical distribution utilities. The aim of the study will be to determine depreciation methodologies and rates that will be applied to all electrical distribution utilities for the purpose of setting rates and regulatory reporting. The study must give due weight to the IFRS requirements regarding depreciation, including componentization.*
>
> *The Kinectrics Report provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances. The Board expects distributors to reflect their consideration of the information contained in the Kinectrics Report when they present an IFRS-based rates application to the Board.*

For the bridge and test years, please confirm if HHHI :

a) used componentization for the underlying PP&E assets, including gross capital costs and accumulated depreciation values and not pooling of assets (i.e. pool assets is not permitted)
b) depreciated separately the significant parts or components of each item of PP&E.
c) used the revised useful lives, and calculated the depreciation expense based on revised service lives. In addition, please provide the calculation required.

d) if the answer in “c” above is “no”, please explain and provide the changes in depreciation expenses and accumulated depreciation for the bridge and test years.

Response:

a) It is confirmed that HHHI used componentization for the underlying PP&E assets, including gross capital costs and accumulated depreciation values and not pooling of assets.

b) It is confirmed that HHHI depreciated separately the significant parts or components of each item of PP&E.

c) It is confirmed that HHHI used the revised useful lives, and calculated the depreciation expense based on revised service lives. The depreciation expense for 2011 and 2012 based on the revised useful lives are presented in Exhibit 4, Tab, Schedule 7, Tables 4- 22 and 4 – 23.

d) Not Applicable.

Low Income Energy Assistance Program (LEAP)

25.
References: Exhibit 3 / 1 / 1 / p. 1; Exhibit 4 / 2 / 3 / p. 9

The Board's Filing Requirements, dated June 22, 2011, section 2.7.2.3 state that a distributor should commit 0.12% of its distribution revenue requirement to emergency financial assistance, and clarifies that the revenue requirement is the forecasted service revenue requirement. HHHI has identified its service revenue requirement as $11,237,701 at the Reference in Exhibit 3. However, the revenue requirement used by HHHI is $10,714,114 and the LEAP provision is rounded up to $13,000.

a) Please provide an alternative calculation based on the service revenue requirement described in Exhibit 3.

b) Please state whether or not HHHI 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.

Response:

a) The alternative calculation based on the service revenue requirement described in Exhibit 3 is presented in below in Table OEB 1-11.

Table OEB 1-11 : Revised LEAP Funding Requirement

LEAP Funding Requirement		Amount
2012 Service Revenue Requirement		11,237,701
LEAP Funding - %		0.12%
LEAP Funding Amount		**13,485**

b) HHHI did not include any amount in its 2012 Test year revenue requirement for any legacy program(s), such as Winter Warmth.

Charitable Donations

26.
References: Exhibit 4 / 2 / 2 / p. 2; Exhibit 4 / 2 / 3 / pp. 2 & 9

a) Please describe the forecasted charitable donations in detail, in particular whether they are designed to provide assistance to HHHI's customers for purposes described in the Board's Filing Requirements, June 22, 2011,section 2.7.2.5.

b) Please explain why HHHI's annual donations have fluctuated since 2008 over a range from less than $7000 up to nearly $30,000, and why the forecasted amount is at the top of this range.

c) Charitable donations are shown as $0 in the 2010 PILs return (Exhibit 4 / Appendix D) and in the test year PILs spreadsheet filed with HHHI's pre-filed evidence, but are shown as $6489 and $30,000 respectively in Table 4-9. Should these entries be the same in both places, and if so which are the right numbers?

d) Table 4-10 (Exhibit 4 / 2 / 3 / p. 2) shows a $20,905 reduction in charitable donations as a cost driver, which is apparently inconsistent with the request for approval of $30,000. Please explain or correct this inconsistency.

Response:

a) The forecasted charitable donation of $30,000 is for donations to community organizations. The amount does not include any contributions to provide assistance to the distributor customers in paying their electricity bills and assistance to low income customers as per section 2.7.25 of the Filing Requirements.

HHHI did not include the charitable donations in the 2012 revenue requirement.

b) Please see response to part a above.

c) The entries should be the same in both places. For 2010, the amount should be $0 and for 2012 should be $30,000.

d) Please see response to part a above.

Provision for PILs

27.
References: Excel file Test Year Income Tax, Sheet T 'PILs,Tax Provision'; Exhibit 4/3/1

a) Please confirm that the capital tax rate applicable to Capital Tax in 2010 in Table 4-24 should be 0.075%, i.e. half of 0.15%, rather than 0.75% as shown.

b) The tax rate assumed in the pre-filed Excel spreadsheet (item M in worksheet T) is 15.5%. The rate used in Table 4-24 in Exhibit 4 is 26.5%. Please reconcile these assumptions and/or provide an explanation of this apparent inconsistency.

c) Grossed-up PILs in the pre-filed Excel spreadsheet (item U in worksheet T) is $67,791. Income Tax in Table 4-24 in Exhibit 4 is $131,542. Please reconcile these assumptions and/or provide an explanation of this apparent inconsistency.

Response:

a) It is confirm that the capital tax rate applicable to Capital Tax in 2010 in Table 4-24 should be 0.075%, i.e. half of 0.15%, rather than 0.75% as shown.

b) The tax rate in the pre-filed Excel spreadsheet (item M in worksheet T) of 15.5% is a calculate rate from the Board's model. Because HHHI taxable income is less than $500,000, the model used the small business rate of (Federal 11% + Ontario 4.5%). HHHI used the combined rate of 26.5%.

c) The tax calculated on the Board's Model is based on the small business rates as explained part b) above. Thus resulting in a lower tax before and after gross up when compare to amounts shown in table 2 -24.

Smart Meter Entity

28.
References: Exhibit 4 / 2 / 3 / p. 6; Board Decision, Powerstream [EB-2010-0209], p. 14

HHHI has included a forecast cost of $135,000 for its cost from a fee from the IESO for the Smart Meter Entity.

a) Please describe the assumptions made by HHHI in formulating this amount.

b) Was HHHI aware of the referenced Board Decision denying Powerstream's request to cover a forecast MDM/R cost forecast on the basis that it was premature, at least until such time as the Board approves an IESO fee for the service?

Response:

a) HHHI derived the Smart Meter Entity Fee of $135,000 by using the following methodology:
(20,500 customers x $0.55 per month x 12 months).

b) HHHI recently became aware of the Board Decision denying Powerstream's request to cover a forecast MDM/R cost forecast on the basis that it was premature. HHHI will remove it MDM/R cost $135,000 for its 2012 revenue requirement but request that Board allow for any such amount to capture in a deferral account to be recovered in the future.

Inflation Rate

29.
Reference: Exhibit 4 / 1 / 1 / p. 2

With Reference to the Statistics Canada source cited in the footnote to Table 4-1, it is not clear how the inflation index used by HHHI was derived from that source. Please provide additional information on the inflation index of 1.0%, used to prepare HHHI's test year forecast of expenditures.

Please explain

a) whether the index was applied for 12 months or only 6 months,
b) whether the index included all consumer-good categories or did it exclude some categories,
c) whether the index was seasonally adjusted.

Response:

a) The inflation index of 1.0%, cited in the footnote of Table 4-1 should not have been included in the table.

b) Please refer to part a).

c) Please refer to part a).

Affiliate Transactions

30.
Reference: Exhibit 4 / 2 / 5 / p. 2; Exhibit 4 / Appendix B

Table 4-15 is titled **"**Purchases of Services from Non-Affiliate Suppliers". The preamble of each of the Service Agreements filed in Appendix B provides for the affiliate to "provide various services" to HHHI.

Please confirm that the revenue requirement does not include a component of cost of any such services; otherwise please provide a table similar to Table 4-15 for the costs of services from affiliate suppliers.

Response:

HHHI confirms that the revenue requirement does not include any component of costs for services from affiliate suppliers.

Depreciation

31.

Reference: Exhibit 4 / 2 / 7 / p. 6

a) Total Depreciation in Table 4-23 is $1,834,363, and depreciation in the RRWF 'Revenue Requirement' is $1,624,165. Which amount is correct?

b) Several accounts do not have an asset life entered in column 'f' of Table 4-23, and the corresponding depreciation rate in column 'g' is also blank. Please provide the missing data, or an explanation of why it is missing.

c) Some of the accounts have no depreciation expense in column 'h', despite having a net fixed asset balance in column 'e', for example Account 1955. Please provide amounts for column 'h' if there should be an amount, or an explanation of why it should be blank.

d) Some accounts have depreciation amounts in column 'h' that do not appear to be based on the formula, for example Account 1915. Please provide an explanation of how the formula was used or an explanation of when it is to be over-ridden.

Response:

a) The depreciation in Table 4-23 of $1,834,363 is the total depreciation. The depreciation in the RRWF 'Revenue Requirement' of $1,624,165 is total depreciation less depreciation for transportation equipment ($1,834,363 – $210,198) which included in burdens.

b) Table OEB 1-12 below is an updated Table 4-23. Also, please refer to HHHI interrogatory response to Energy Probe question 31 part a.

Table OEB 1-12 : Revised Table 4-23 from Application

Account	Description	Opening Balance (a)	Less Fully Depreciated[1] (b)	Net for Depreciation (c) = (a) - (b)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [2]	Years (f)	Depreciation Rate (g) = 1 / (f)	Depreciation Expense (h) = (e) / (f)	Did Depreciation Rate in "g" Change (Yes/No)? [3]
1805	Land	$ 359,609		$ 359,609	$ -	$ 359,609			$ -	Yes
1808	Buildings	$ 3,080,205		$ 3,080,205	$ -	$ 3,080,205	42	2%	$ 82,064	Yes
1810	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	Yes
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -			$ -	Yes
1820	Distribution Station Equipment <50 kV	$ 4,318,466		$ 4,318,466	$ 54,745	$ 4,345,839	40	3%	$ 152,917	Yes
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1830	Poles, Towers & Fixtures	$ 17,274,087		$ 17,274,087	$ 3,960,619	$ 19,254,396	50	2%	$ 343,098	Yes
1835	Overhead Conductors & Devices	$ 7,245,498		$ 7,245,498	$ 2,397,685	$ 8,444,340	50	2%	$ 126,334	Yes
1840	Underground Conduit	$ 1,373,099		$ 1,373,099	$ 466,069	$ 1,606,134	50	2%	$ 28,062	Yes
1845	Underground Conductors & Devices	$ 5,050,704		$ 5,050,704	$ 389,624	$ 5,245,516	30	3%	$ 88,643	Yes
1850	Line Transformers	$ 7,223,017		$ 7,223,017	$ 514,137	$ 7,480,085	40	3%	$ 128,283	Yes
1855	Services (Overhead and Underground)	$ 2,750,180		$ 2,750,180	$ -	$ 2,750,180	40	3%	$ 60,785	Yes
1860	Meters	$ 1,048,410		$ 1,048,410	$ -	$ 1,048,410	20	5%	$ 27,901	Yes
1860	Meters (Smart Meters)	$ 3,768,873		$ 3,768,873	$ -	$ 3,768,873	15	7%	$ 251,625	Yes
1905	Land	$ -		$ -	$ -	$ -			$ -	Yes
1906	Land Rights	$ -		$ -	$ -	$ -			$ -	Yes
1908	Buildings & Fixtures	$ 146,075		$ 146,075	$ 10,000	$ 151,075	42	2%	$ -	Yes
1910	Leasehold Improvements	$ -		$ -	$ -	$ -			$ -	Yes
1915	Office Furniture & Equipment (10 Years)	$ -		$ -	$ -	$ -			$ -	Yes
1915	Office Furniture & Equipment (5 Years)	$ 412,782		$ 412,782	$ 300	$ 412,932	5	20%	$ 19,736	Yes
1920	Computer Equipment - Hardware	$ 1,072,364		$ 1,072,364	$ 180,000	$ 1,162,364	3	33%	$ 134,832	Yes
1920	Computer Equip. - Hardware (Post Mar. 22/04)	$ -		$ -	$ -	$ -			$ -	Yes
1920	Computer Equip. - Hardware (Post Mar. 19/07)	$ -		$ -	$ -	$ -			$ -	Yes
1925	Computer Software	$ 1,218,701		$ 1,218,701	$ 363,000	$ 1,400,201	2	50%	$ 155,699	Yes
1930	Transportation Equipment	$ 2,519,028		$ 2,519,028	$ 230,000	$ 2,634,028	8	13%	$ 210,198	Yes
1935	Stores Equipment	$ 86,472		$ 86,472	$ -	$ 86,472	10	10%	$ 3,546	Yes
1940	Tools, Shop & Garage Equipment	$ 558,091		$ 558,091	$ 43,170	$ 579,676	10	10%	$ 52,314	Yes
1945	Measurement & Testing Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1950	Power Operated Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1955	Communications Equipment	$ 75,194		$ 75,194	$ -	$ 75,194	50	2%	$ -	Yes
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	Yes
1960	Miscellaneous Equipment	$ -		$ -	$ -	$ -			$ -	Yes
1975	Load Management Controls Utility Premises	$ 563,902		$ 563,902	$ -	$ 563,902	40	3%	$ 12,037	Yes
1980	System Supervisor Equipment	$ 885,854		$ 885,854	$ 52,613	$ 912,161	20	5%	$ 46,844	Yes
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -			$ -	Yes
1995	Contributions & Grants	-$ 6,473,408		-$ 6,473,408	-$ 1,284,968	-$ 7,115,892	50	2%	-$ 90,557	Yes
etc.		$ -		$ -	$ -	$ -			$ -	Yes
		$ -		$ -	$ -	$ -			$ -	Yes
	Total	$ 54,557,203	$ -	$ 54,557,203	$ 7,376,995	$ 58,245,701			$ 1,834,363	

c) Please refer to HHHI interrogatory response to Energy Probe question 38 part a.

d) Please refer to HHHI interrogatory response to Energy Probe question 38 part c.

Ontario Municipal Employees Retirement System Pension Costs

32.

Reference: Exhibit 4 / 2 / 6

HHHI has submitted in the reference, at p. 5, that it has

> *"anticipated an increase in OMERS pension costs regarding a 3-year, 1% per year increase in OMERS premiums beginning in 2011. OMERS estimates the 1% contribution rate increase in 2011 would increase the amount an employer contributes to OMERS by about 10-13%"*

HHHI has also provided Tables 4-16, 4-17 and 4-18 showing Compensation and Benefits, OMERS Pension Premiums, and Employee Future Benefits respectively.

Please explain how HHHI made its forecast of OMERS premiums in the test year (which is an increase of $160,000 or approximately 75% more than 2010 actual in Table 4-17), and relate this to the increase in its forecast of salary and wages (which is approximately 20% more than 2010 actual).

Response:

The Budget model calculates OMERS Premiums based on 8.3% on the first $48,300 of Contributory Earnings and 12.8% on the balance.

Treatment of Pensions and Other Post-Employment Benefits

33.
References: Exhibit 4 / 2 / 6 / p. 6 ; Exhibit 4 / Appendix C 'Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits'

The cover sheet of the report filed as Appendix C notes that it is a draft version dated March 23, 2010.

a) Has the report been finalized in the meantime? Is there a signed version of p. 19? If not, why not?

b) If the report has been finalized, please provide any changes that were made to the draft that HHHI has filed.

c) If the actuarial report is used in formulating the information in Table 4-18, "Employee Future Benefits", please indicate which results in the report are linked to HHHI's actual or forecasted information in Table 4-18.

Response:

a) Yes, the report is finalized. Please refer to Appendix OEB 1-C.

b) HHHI confirms no changes were made to the draft that was filed.

c) Please refer to Appendix OEB 1-C.

34.

References: IASB revisions to IAS 19, Employee Benefits, June 2011; Exhibit 4 / Appendix C 'Report on the Actuarial Valuation of Post-Retirement Non-Pension Benefits'

The IAS revisions are effective January 1, 2013, but early adoption is permitted. These revisions include the elimination of the option to defer recognition of gains and losses, known as the "corridor method".

a) Please confirm if HHHI has unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011).

b) If yes, what is the accounting treatment of the unamortized actuarial gains and losses and past service costs at the date of transition (January 1, 2011)?

c) What is the proposed regulatory treatment of these amounts – are these amounts incorporated into the revenue requirement? Please explain.

d) Please confirm whether or not HHHI has adopted the revisions to IAS 19, Employee Benefits, and state whether the impacts of this early adoption are incorporated in the revenue requirement.

Response:

a) HHHI confirms that it has unamortized actuarial gain and past service costs at the date of transition. Please refer to Appendix OEB 1-D.

b) The unamortized gains and losses were not recorded at the date of transition.

c) The unamortized gains/losses were included in revenue requirement to the extent of the amortization of these amounts over estimated benefit expense and accrued benefit obligation.

d) HHHI has not early adopted the changes in IAS 19 and so there has been no change in revenue requirement compared to the audited F/S under CGAAP.

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.

Has HHHI adopted the default weighting factors as appropriate for itself. If so, please provide documentation as specified in the Board's Report. Alternatively, please provide descriptions and weighting factors for Services and Billing Costs, and a calculation of the impact on the respective class revenues.

Response:

The cost allocation study has been updated to reflect weighting factor specific to HHHI. The results of using the specific weighting factors are provided in the updated cost allocation study.

The updated cost allocation model will be filed as part of the response to the interrogatories.

37.
Reference: Exhibit 7 / Appendix A and B

Exhibit 7 / Appendix B consists of several worksheets from an alternative run of the cost allocation model, which appear to differ from the worksheets in Appendix A only with respect to Miscellaneous Revenue, with the total in Appendix B being larger by $50,000.

a) Please confirm that this is the only difference, and that the version in Appendix A is consistent with the remainder of the application.

b) Please explain which revenue account(s) differ between the two versions, and what assumptions have been made underlying both versions of the cost allocation model.

Response:

a) It is confirmed that this is the only difference, and that the version in Appendix A is consistent with the remainder of the application.

b) The revenue that differs between the two versions is 4210- Rent from Electric Property. As indicated in response to question 36 above, HHHI will file an updated cost allocation model and will make the correction to the miscellaneous revenue.

38.

Reference: Exhibit 1 / 1 / 11; Board Report "Review of Electricity Distribution Cost Allocation Policy", March 31, 2011 [EB-2010-0219]

In HHHI's previous cost-of-service application the Board approved the situation in which HHHI would charge its General Service 1000-4999 kW rates to Hydro One at two delivery points (EB-2007-0696, Decision p. 18). The Decision noted that the situation was under review more generally and instructed HHHI to remain up-to-date on the matter. In this application, HHHI has stated that it is not a host distributor.

a) Does HHHI continue to provide power to Hydro One at the delivery points discussed in the previous proceeding? If not, in which year did this situation change?

b) Please confirm that there are no other similar delivery points to Hydro One or another distributor?

c) If HHHI continues to deliver power to Hydro One, does HHHI have a proposal that future treatment of Hydro One as an embedded distributor that would be consistent with changes in the Board's cost allocation policy at p. 32 of the referenced Report?

Response:

a) Yes. HHHI still provides power to Hydro One at the delivery points discussed in the previous proceeding.

b) It is confirmed that there are no other similar delivery points to Hydro One or another distributor.

c) HHHI will be making an application in 2013 to treat of Hydro One as an embedded distributor that would be consistent with changes in the Board's cost allocation policy at p. 32 of the referenced Report.

Total Loss Factor

39.
References: Exhibit 2 / Appendix C / p. 15; Exhibit 8 / 4 / 1

a) Please provide a calculation of the Total Loss Factor ("TLF") based on the most recent three-year history, together with an explanation of why the TLF being applied for should include the relatively high losses incurred in 2006 and 2007.

b) Has HHHI considered that its voltage conversion capital projects described in Exhibit 2 may decrease line losses? If so, does it expect that any improvements would reverse the trend of increased Distribution Loss Factor ("DLF") shown in row G, Table 8-9? If it has not considered the possibility of this favourable outcome in DLF, why not?

Response:

a) The Total Loss Factor ("TLF") based on the most recent three-year history is presented below as Table OEB 1-13. HHHI calculated its loss factor based on the historical five years which is preferred by the OEB in accordance with section 2.11.7 of the Filing Requirements. HHHI believes that the five year average is more reflective of its losses as it would capture all of the different variables contributing the losses.

Table OEB 1-13 : Three (3) Year TLF Average

		Historical Years			3-Year Average
		2008	2009	2010	
	Losses Within Distributor's System				
A(1)	"Wholesale" kWh delivered to distributor (higher value)	507,787,443	499,800,409	520,540,577	509,376,143
A(2)	"Wholesale" kWh delivered to distributor (lower value)	491,090,370	483,365,966	503,424,156	492,626,831
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)	-	-	-	-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	491,090,370	483,365,966	503,424,156	492,626,831
D	"Retail" kWh delivered by distributor	480,192,790	472,272,010	491,761,405	481,408,735
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)				-
F	Net "Retail" kWh delivered by distributor = **D - E**	480,192,790	472,272,010	491,761,405	481,408,735
G	Loss Factor in Distributor's system = **C / F**	102.27%	102.35%	102.37%	102.33%
	Losses Upstream of Distributor's System				
H	Supply Facilities Loss Factor	1.034	1.034	1.034	1.034
	Total Losses				
I	Total Loss Factor = **G x H**	105.75%	105.83%	105.85%	105.81%

b) HHHI has considered that the voltage conversion projects will decrease line losses, however, due to the large overhead, rural area makeup of HHHI, it would be difficult to assume a specific amount at this time.

Retail Transmission Service Rates

40.
Reference: Exhibit 8 / 3 / 1; RTSR Adjustment Work Form

Worksheet '8 – Forecast Wholesale' shows that HHHI's wholesale cost includes a component of about 10% being established by the IESO's Uniform Transmission Rates. HHHI's evidence is that it is totally embedded, which would seemingly imply that only Hydro One's Sub-Transmission RTSRs would establish the wholesale cost.

Please provide an explanation of this apparent inconsistency, together with any additional evidence or corrections that may be necessary.

Response:

HHHI is totally embedded to HONI in the respect that HHHI is fed entirely by HONI feeders outside of HHHI's boundaries. However, at two of the seven feeders, HHHI owns the infrastructure up to the connection points at the HONI Transformer station. The IESO bills wholesale costs on the energy from these two feeders. As such, no additional evidence or corrections to the information filed is required.

Retail Service Charges

41.
References: Exhibit 8 / 8 / 4 / p. 7; Exhibit 9 / 3 / 1 / p. 2

The balance in Account 1518 proposed for disposition in Exhibit 9 is $31,418 credit.

a) Please provide a description of the incremental costs that affect Account 1518, and a schedule of the approximate amount of incremental cost recorded in these accounts.

b) Please provide the approximate annual revenue from each of the Retailer Charges that affect Account 1518, i.e. charges for establishing a service agreement, monthly fixed and variable charges, and billing-related charges.

c) Please confirm that HHHI's accounting practices are consistent with Article 490 of the Accounting Procedures Handbook, with respect to offsetting entries of incremental cost amounts from operating accounts, for example from Account 5340 to the variance account.

d) Has HHHI considered a change to any of the retail service charges to more closely match the corresponding incremental cost?

Response:

a) The incremental costs that are recorded in Account 1518 are presented below in Table OEB 1-14.

Table OEB 1-14 : Incremental Cost Recorded in Account 1518

Incremental Retail Costs	2008	2009	2010
Total incremental labour costs related to retailer Services	11,389	8,749	10,069
Hub maintenance costs	7,313	8,390	7,851
Total	**18,702**	**17,139**	**17,920**

b) The approximate annual revenue from each of the Retailer Charges that affect Account 1518 is presented in Table OEB 1-15 below.

Table OEB 1-15 : Retailer Charge Revenue

Retailer Charges	2008	2009	2010
Retail Monthly Service Charge	3,560	3,620	3,480
Avoided Cost Credit	(52)	-	-
Monthly Billing Charge	9,386	9,692	8,491
Retail Variable Charge	15,601	16,320	14,646
Service Agreement	200	(100)	100
	28,695	29,532	26,716

c) It is confirmed that HHHI's accounting practices are consistent with Article 490 of the Accounting Procedures Handbook, with respect to offsetting entries of incremental cost amounts from operating accounts.

d) HHHI did not consider a change to any of the retail service charges to more closely match the corresponding incremental costs that this time.

Credit Card Convenience Fee

42.
Reference: Exhibit 8 / 8 / 4 / p. 6

a) HHHI's Conditions of Service, found on its web-site, identifies at p. 23 that a convenience fee will be charged on security deposits made by credit card. Please provide an explanation for the nature of the costs being recovered by this fee.
b) HHHI's Conditions of Service identifies at p. 26 that a Board-approved fee may be charged for certain requests for aggregated customer information. Please provide an explanation for the nature of the costs being recovered by this fee.
c) Please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet, for example amongst its proposed Specific Service Charges.

Response:

a) The convenience fee is charged and collected directly by the Credit Card Merchant Company providing the service on behalf of HHHI.

b) HHHI's Conditions of Service, page 26, Section 2.5, Customer Information states "Hydro may charge an OEB approved fee for all other requests for aggregated information" is in fact referring to the current Specific Service Charges as approved in the current tariff of rates

c) As per response to question 42 b) above, these rates are included in Specific Service Charges on HHHI's Tariff sheet.

Deferral and Variance Accounts

43.

Reference: Exhibit 9, Tab 2, Schedule 1, Page 13; Exhibit 9, Appendix B-DVA Continuity Schedule Work Form; Chapter 2 of Filing Requirements

The Provincial Sales Tax ("PST") and the Federal Goods and Services Tax were harmonized into the Harmonized Sales Tax ("HST") effective July 1, 2010. As a result of this harmonization, applicants may benefit from an overall net reduction in costs in the form of Input Tax Credits ("ITCs"). This arises due to cost decreases from the receipt of additional ITCs on the purchases of goods and services previously subject to PST that become subject to the HST. These cost decreases may be partially offset by cost increases on certain items that were not previously subject to PST but become subject to the HST with no additional ITCs having been granted (i.e., these items are subject to recaptured ITC requirements).

During the 2010 IRM application process, the Board directed electricity distributors to record in Account 1592 PILs and Tax Variances, Sub-account HST/OVAT Input Tax Credits ("ITCs"), beginning July 1, 2010, the incremental ITCs received on distribution revenue requirement items that were previously subject to PST and became subject to HST.

The Board provided accounting guidance on this matter and provided a simplified approach designed to facilitate administrative cost-saving opportunities. [Frequently Asked Questions on the Accounting Procedures Handbook, December 23, 2010]

No additional 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. For the 2012 Test Year for example entries to record variances in the sub-account of Account 1592 would cover the period July 1, 2010 to December 31, 2011 since the Test Year, which starts January 1, 2012 would include the HST impacts in it revenue requirement for 2012.

In Chapter 2, the Board expects distributors to file for disposition of account 1592 in their cost of service applications.

HHHI's application is as follows (Exhibit 9 / 2 / 1 / p. 13):

> *HHHI requests leave to discontinue tracking HST/OVAT/ITC as at April 30, 2012. HHHI also requests the Board allow that account 1592 remain open, pending Board approval to discontinue tracking costs effective April 30, 2012 and until such time as HHHI files its 2014 IRM rate application at which time HHHI will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1592.*

a) Please explain why HHHI is not requesting disposition of Account 1592.

b) Please complete and file Appendix 2-T Deferred PILs Account 1592 Balances from Chapter 2 of the Filing Requirements (June 22, 2011).

Response:

a) HHHI did not request disposition of Account 1592 because HHHI would be recording transactions in this account until December 31, 2011. The balance will be audited in Q1 of 2012.

b) Appendix 2-T Deferred PILs Account 1592 Balances from Chapter 2 of the Filing Requirements is presented below as Table OEB 1-16.

Table OEB 1-16 : Account 1592 Deferred Balances

Tax Item		Principal as of December 31, 2010
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from May 1, 2006 to April 30, 2007		
Large Corporation Tax grossed-up proxy from 2006 EDR application PILs model for the period from January 1, 2006 to April 30, 2006 (4/12ths of the approved grossed-up proxy), if not recorded in PILs account 1562		
Ontario Capital Tax rate decrease and increase in capital deduction for 2007		
Ontario Capital Tax rate decrease and increase in capital deduction for 2008		
Ontario Capital Tax rate decrease and increase in capital deduction for 2009		
Ontario Capital Tax rate decrease and increase in capital deduction for 2010		
Capital Cost Allowance class changes from 2006 EDR application for 2006		
Capital Cost Allowance class changes from 2006 EDR application for 2007		
Capital Cost Allowance class changes from 2006 EDR application for 2008		
Capital Cost Allowance class changes from 2006 EDR application for 2009		
Capital Cost Allowance class changes from 2006 EDR application for 2010		
Capital Cost Allowance class changes from any prior application not recorded above. Please provide details and explanation separately.		
HST/OVAT Input tax Credits (ITCs)		$ 32,432
Total		$ 32,432

44.

Reference: Exhibit 9, Tab 2, Schedule 3, Page 4; Chapter 2 of the Filing Requirements: Section 2.12.3; Exhibit 9, Tab 2, Schedule 1, Page 8

According to the Board letter of April 23, 2010 on the Special Purpose Charge:

> *In accordance with section 9 of the SPC Regulation, recovery of your SPC assessment is to be spread over a one-year period, starting from the date on which you begin billing to recover your assessment. The request for disposition of the balance in "Sub-account 2010 SPC Variance" and "Sub-account 2010 SPC Assessment Carrying Charges" should be made after that one-year period has come to an end, and all bills that include amounts on account of that assessment have come due for payment.*

Chapter 2, Section 2.12.3 of the Filing Requirements states:

> *In accordance with Section 8 of the SPC Regulation, distributors are required to apply no later than April 15, 2012 for an order authorizing the disposition of any residual balance in sub account 2010 SPC Assessment Variance.*
>
> *The Board expects that requests for disposition of the balance in Sub-account 2010 SPC Assessment Variance and associated carrying charges will be addressed as part of the proceedings to set rates for the 2012 rate year. Exceptions may apply in cases where this approach would result in non-compliance with the timeline set out in section 8 of the SPC Regulation.*

HHHI stated:

> *HHHI established account 1521 Sub-account 2010 SPC Variance, and Sub-account 2010 SPC Assessment Carrying Charges in accordance with the Board's April 23, 2010 letter. HHHI's share of the Assessment for MEI Conservation and Renewable program of $189,128 was recognized in this account in April 2010, and customer billing for recoveries commenced May 1, 2010. As per the Board's instructions in the letter dated April 9, 2010, HHHI has recovered the SPC assessment over a one-year period on consumption after May 1, 2010 (pro-rated). As HHHI bills residential customers bi monthly, final SPC charges have been billed as of August 15, 2011. HHHI requests the Board allow that account 1521 remain open until such time as HHHI files its 2013 IRM rate application at which time HHHI will apply to the Board for an order to clear any audited debit or credit balance remaining in account 1521.*

a) Please provide the most recent balance in account 1521, "Sub-account 2010 SPC Variance".

b) Please provide the forecasted carrying charges in "Sub-account 2010 SPC Assessment Carrying Charges" as of April 30, 2011.

c) Please explain why HHHI is not seeking the disposition of the residual balances in account 1521 sub-account 2010 SPC Assessment Variance and sub-account 2010 SPC Assessment Carrying Charges in accordance with the Board's April 23, 2919 letter and Section 2.12.3 of the Filing Requirements.

d) Is HHHI in non-compliance with the timeline set out in Section 8 of the SPC Regulation? Please explain.

Response:

a) The balance in account 1521 "Sub-account 2010 SPC Variance" at September 30, 2011 is ($15,398.48).

b) The forecasted carrying charges in "Sub-account 2010 SPC Assessment Carrying Charges" as of April 30, 2012 is $728.01

c) Please refer to HHHI interrogatory response to Energy Probe question 45.

d) No. The obligation on distributors in section 8 of the SPC Regulation is to make application to the Board by April 2012. If the Board will allow disposition on non-audited balances, HHHI would be willing to include the balance of Account 1521, including projected carrying costs to April 30, 2012 in our DVA disposition request.

45.
Reference: Exhibit 9, Tab 3, Sch. 2, Page 3

The proposed rate riders for non-RPP customers in the Residential and GS<50 kW classes in Table 9-13 appear to be inconsistent with the sub-account balances in Table 9-9 and the billing kWh amounts in Table 9-8.

Please verify the amounts in Table 9-8 and 9-9 and show the derivation of the non-RPP rate riders for those classes.

Response:

The amount in Table 9-9 is the total amount to be recovered. The rate ride Table 9-13 is based on a two year recovery period. The calculation is presented below in Table OEB 1-17.

Table OEB 1-17 : Rate Rider Calculation

		Residential	GS < 50 kW	GS >50 to 999 kW	GS 999 to 4,999 kW	Sentinel Lights	Street Lighting	USL
Balance to be collected or refunded, Variable	$ (1,675,714)	$ (685,885)	$ (174,935)	$ (424,774)	$ (383,646)	$ (2,347)	$ (1,288)	$ (2,841)
Balance to be collected or refunded, Variable - Non RPP Customers (GA)	$ 2,303,654	$ 220,317	$ 45,518	$ 968,319	$ 1,025,388	$ 6,880	$ 27,866	$ 9,367
	$ 627,940	**$ (465,568)**	**$ (129,417)**	**$ 543,545**	**$ 641,742**	**$ 4,533**	**$ 26,578**	**$ 6,526**
Number of years for Variable	2							
Balance to be collected or refunded per year, Variable	$ (837,857)	$ (342,942)	$ (87,467)	$ (212,387)	$ (191,823)	$ (1,173)	$ (644)	$ (1,420)
Balance to be collected or refunded per year, Variable - Non RPP (GA)	$ 1,151,827	$ 110,159	$ 22,759	$ 484,159	$ 512,694	$ 3,440	$ 13,933	$ 4,683

Class	Residential	GS < 50 kW	GS >50 to 999 kW	GS 999 to 4,999 kW	Sentinel Lights	Street Lighting	USL
Deferral and Variance Account Rate Riders, Variable	$ (0.0016)	$ (0.0017)	$ (0.6508)	$ (0.6811)	$ (0.7926)	$ (0.0812)	$ (0.0015)
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Deferral and Variance Account Rate Riders, Variable - Non RPP Customers	$ 0.0011	$ 0.0002	$ 1.4835	$ 1.8205	$ 2.3236	$ 1.7575	$ 0.0049
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Rate Rider for all Customer Class	***$ (0.0016)***	***$ (0.0017)***	***$ (0.6508)***	***$ (0.6811)***	***$ (0.7926)***	***$ (0.0812)***	***$ (0.0015)***
Rate Rider for for Non -RPP Customers (GA)	***$ 0.0011***	***$ 0.0002***	***$ 1.4835***	***$ 1.8205***	***$ 2.3236***	***$ 1.7575***	***$ 0.0049***

46.

References: Exhibit 8 / 7 / 1; Exhibit 9 / 3 / 2 / p. 3; Board Report *'Electricity Distributor Deferral & Variance Account Review'* (EDDVAR) July 31, 2009; Exhibit 8 / Appendix A.

HHHI has requested a two-year period for the Deferral and Variance Account Disposition Rate Rider.

The EDDVAR Report states at p. 24:

> *… the default disposition period used to clear the Account balances through a rate rider should be one year. However, a distributor could propose a different disposition period to mitigate rate impacts or address any other applicable considerations, where appropriate.*

a) On the Group 1 and Group 2 Deferral and Variance Account (DVA) rate rider and Non-RPP Global Adjustment rate rider by classes, please explain why HHHI is proposing 2 years instead of 1 year for the disposition period.

b) If the reason for proposing a 2-year recovery is based on a bill impact mitigation study, please provide the calculations.

c) Please re-calculate the rate riders and associated bill impacts using a disposition period of one year.

Response:

a) HHHI proposed to use a two year recovery period to lessen the financial burden on its customers.

b) HHHI didn't propose the 2-year recovery based on a bill impact mitigation study.

c) The rate riders and the bill impacts of a typical residential and GS < 50 kW customer using a disposition period of one year are presented below in Tables OEB 1-18, OEB 1-19 and OEB 1-20.

Table OEB 1-18 : Rate Impact Using One Year Disposition Period

		Residential	GS < 50 kW	GS >50 to 999 kW	GS 999 to 4,999 kW	Sentinel Lights	Street Lighting	USL
Balance to be collected or refunded, Variable	$ (1,675,714)	$ (685,885)	$ (174,935)	$ (424,774)	$ (383,646)	$ (2,347)	$ (1,288)	$ (2,841)
Balance to be collected or refunded, Variable - Non RPP Customers (GA)	$ 2,303,654	$ 220,317	$ 45,518	$ 968,319	$ 1,025,388	$ 6,880	$ 27,866	$ 9,367
	$ 627,940	**$ (465,568)**	**$ (129,417)**	**$ 543,545**	**$ 641,742**	**$ 4,533**	**$ 26,578**	**$ 6,526**
Number of years for Variable	1							
Balance to be collected or refunded per year, Variable	$ (1,675,714)	$ (685,885)	$ (174,935)	$ (424,774)	$ (383,646)	$ (2,347)	$ (1,288)	$ (2,841)
Balance to be collected or refunded per year, Variable - Non RPP (GA)	$ 2,303,654	$ 220,317	$ 45,518	$ 968,319	$ 1,025,388	$ 6,880	$ 27,866	$ 9,367

Class	Residential	GS < 50 kW	GS >50 to 999 kW	GS 999 to 4,999 kW	Sentinel Lights	Street Lighting	USL
Deferral and Variance Account Rate Riders, Variable	$ (0.0033)	$ (0.0034)	$ (1.3016)	$ (1.3623)	$ (1.5852)	$ (0.1624)	$ (0.0030)
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Deferral and Variance Account Rate Riders, Variable - Non RPP Customers	$ 0.0023	$ 0.0004	$ 2.9670	$ 3.6411	$ 4.6473	$ 3.5150	$ 0.0099
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh
Rate Rider for all Customer Class	***$ (0.0033)***	***$ (0.0034)***	***$ (1.3016)***	***$ (1.3623)***	***$ (1.5852)***	***$ (0.1624)***	***$ (0.0030)***
Rate Rider for for Non -RPP Customers (GA)	***$ 0.0023***	***$ 0.0004***	***$ 2.9670***	***$ 3.6411***	***$ 4.6473***	***$ 3.5150***	***$ 0.0099***

Table OEB 1-19 : Residential Rate Impact Using One Year Disposition Period

RESIDENTIAL

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			12.94			14.40	1.46	11.28%	12.58%
800 kWh	Distribution (kWh)	800	0.0121	9.68	800	0.0135	10.80	1.12	11.57%	9.44%
	Low Voltage Rider (kWh)	800	0.0012	0.96	800	0.0008	0.64	(0.32)	(33.33%)	0.56%
	Smart Meter Rider (per month)			1.50			2.31	0.81	53.91%	2.02%
	LRAM & SSM Rider (kWh)	800	0.0000	0.00	800	0.0007	0.56	0.56		0.49%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00		0.00%
	Late Payment (kWh)	800	0.0000	0.00	800	0.0000	0.00	0.00		0.00%
	Deferrral & Variance Acct (kWh)	800	0.0019	1.52	800	(0.0033)	(2.60)	(4.12)	(271.16%)	(2.27%)
	Distribution Sub-Total			**26.60**			**26.11**	**(0.49)**	**(1.85%)**	**22.81%**
	Retail Transmisssion (kWh)	840	0.0098	8.23	848	0.0102	8.65	0.42	5.10%	7.56%
	Delivery Sub-Total			**34.83**			**34.76**	**(0.07)**	**(0.21%)**	**30.37%**
	Other Charges (kWh)	840	0.0072	6.05	848	0.0072	6.11	0.06	0.98%	5.34%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0680	40.80	1.80	4.62%	35.65%
	Cost of Power Commodity (kWh)	240	0.0750	17.99	248	0.0790	19.60	1.61	8.95%	17.13%
	SPC (kWh)	840	0.0003	0.25	840	0.0000	0.00	(0.25)	(100.00%)	0.00%
	Total Bill Before Taxes			**98.12**			**101.27**	**3.15**	**3.21%**	**88.50%**
	GST		13.00%	12.76		13.00%	13.17	0.41	3.21%	11.50%
	Total Bill			**110.88**			**114.43**	**3.55**	**3.21%**	**100.00%**

Table OEB 1-20 : General Service less than 50 kW Rate Impact Using One Year Disposition Period

GENERAL SERVICE < 50 kW

		2011 BILL			2012 BILL			IMPACT		
		Volume	RATE $	CHARGE $	Volume	RATE $	CHARGE $	$	%	% of Total Bill
Consumption	Monthly Service Charge			28.28			29.64	1.36	4.81%	10.78%
2,000 kWh	Distribution (kWh)	2,000	0.0089	17.80	2,000	0.0093	18.60	0.80	4.49%	6.77%
	Low Voltage Rider (kWh)	2,000	0.0011	2.20	2,000	0.0008	1.60	(0.60)	(27.27%)	0.58%
	Smart Meter Rider (per month)			1.50			2.31	0.81	53.91%	0.84%
	LRAM & SSM Rider (kWh)	2,000	0.0000	0.00	2,000	0.0010	2.00	2.00		0.73%
	Smart Meter Entity ($/Month)			0.00			0.00	0.00		0.00%
	Late Payment (kWh)	2,000	0.0000	0.00	2,000	0.0000	0.00	0.00		0.00%
	Deferrral & Variance Acct (kWh)	2,000	0.0020	4.00	2,000	(0.0034)	(6.75)	(10.75)	(268.70%)	(2.45%)
	Distribution Sub-Total			**53.78**			**47.40**	**(6.38)**	**(11.86%)**	**17.24%**
	Retail Transmisssion (kWh)	2,100	0.0089	18.69	2,120	0.0093	19.72	1.03	5.52%	7.17%
	Delivery Sub-Total			**72.47**			**67.12**	**(5.35)**	**(7.38%)**	**24.41%**
	Other Charges (kWh)	2,100	0.0072	15.12	2,120	0.0072	15.27	0.15	0.98%	5.55%
	Cost of Power Commodity (kWh)	600	0.0650	39.00	600	0.0680	40.80	1.80	4.62%	14.84%
	Cost of Power Commodity (kWh)	1,500	0.0750	112.49	1,520	0.0790	120.11	7.63	6.78%	43.69%
	SPC (kWh)	2,100	0.0003	0.63	2,100	0.0000	0.00	(0.63)	(100.00%)	0.00%
	Total Bill Before Taxes			**239.70**			**243.30**	**$3.60**	**1.50%**	**88.50%**
	GST		13.00%	31.16		13.00%	31.63	0.47	1.50%	11.50%
	Total Bill			**270.86**			**274.93**	**$4.06**	**1.50%**	**100.00%**

47.

Reference: Report of the Board *'Transition to International Financial Reporting Standards ("IFRS")* July 28, 2009 [EB-2008-0408]; *One-Time Administrative Costs of Transition to IFRS*, section 2.7.2; Exhibit 9 / 2 / 3 / p. 4; Exhibit 9 / Appendix B

The Report of the Board states, at p. 27:

> *The Board will establish a deferral account for distributors for incremental one-time administrative costs related to the transition to IFRS. This account is exclusively for necessary, incremental transition costs and is not to include … ongoing compliance costs or impacts on revenue requirement arising from changes in the timing of the recognition of expenses.*
>
> *The Board will not restrict the IFRS transition costs account by establishing a fixed start date for amounts to be recorded. However, the Board cautions distributors that the amounts in the account will be subject to a prudence review before disposition. The criteria of materiality, causation and prudence will be considered at the time of proposed disposition. Only costs that are clearly driven by the necessity of transitioning to IFRS and are genuinely incremental to costs that would have been otherwise incurred will be recoverable in rates. Any distributor that has IFRS related costs already approved in rates must record, in a variance account, the variances between the previously approved costs and actual costs of transitioning to IFRS.*

The Regulatory Assets Continuity Schedule for sub-account 1508, Deferred IFRS Transition Costs shows a balance of $260,671 as of December 31, 2010.

a) Please confirm the Deferred IFRS transition costs show a debit balance of $260,671 as of December 31, 2010. Otherwise, please identify the costs if it is different.

b) Please provide the breakdown of the costs recorded in the IFRS Deferral sub- account as of December 31, 2010. Please provide explanations for each category of costs recorded in the IFRS Deferral account and indicate how the costs recorded meet the criteria of one-time IFRS administrative incremental costs.

c) Please confirm that no capital costs were recorded in this deferral or variance account, One-Time Administrative Costs of Transition to IFRS. If this is not the case, please explain.

Response:

a) The Deferred IFRS transition costs show a debit principal balance of $260,671 as of December 31, 2010 plus carrying charges of $3,674.

b) The costs recorded in the IFRS Deferral sub- account as of December 31, 2010 is presented in Table OEB 1-21 below.

Table OEB 1-21 : IFRS Deferral sub-account Costs

1508 - IFRS Deferral Sub - Account		Amount
Asset Management Costs for IFRS		243,685
Other Costs		8,986
Consulting Costs		8,000
		260,671

c) It is confirmed that no capital costs were recorded in this deferral or variance account, One-Time Administrative Costs of Transition to IFRS.

48.

Reference: *Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, June 13, 2011; Exhibit 9 / 2 / 3; Staff Discussion Paper, "Transition to IFRS" March 31, 2011 / Appendix A

In the Addendum to the Board Report, Appendix A: "Summary of Board Policy", the Board stated at p. 31:

> *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.*

HHHI's request is as follows, at 9 / 2 / 3 / p. 1:

> *HHHI is requesting an Accounting Order to establish a Deferral and Variance account to track the difference relating to PP&E components of rate base as a result of transition to modified IFRS in 2012.*

Differences may arise with Property, Plant, and Equipment balances due to implementing IFRS. HHHI has not provided a calculation or balance in the Board approved PP&E Deferral Account

a) Please confirm if HHHI has performed a calculation or has provided a balance in the Board approved PP&E Deferral Account.

b) If the answer to part "a" above is no, please update the appropriate schedules and calculate a balance for the PP&E Deferral Account.

c) Please provide a breakdown of the amount that is to be recorded in the PP&E deferral account from the transition date to MIFRS that is, as of January 1, 2011. Please provide the supporting analysis of the amounts in this account.

d) Please provide an analysis similar to Appendix A of the *Staff Discussion Paper – Transition to IFRS*. (The paper is available on the Board's web-site *http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2008-0408/Discussion_paper_Transition_to_IFRS_20110331.pdf*

e) Please provide a proposal for the disposition of this deferral account and rationale, referring to the Addendum to the Report of the Board on IFRS.

Response:

a) HHHI has not provided a balance in the Board approved PP&E Deferral Account.

b) The calculating and balance for the PP&E Deferral Account is presented below in Table OEB 1-22.

Table OEB 1-22 : PP&E Deferral Account Calculations

PP&E Deferral Accounts on Transition to MIFRS						
	2010	2011	2012	2013	2014	2015
CGAAP						
Opening Net PP&E	28,170,052	27,281,803				
Additions	1,860,433	4,767,523				
Depreciations	(2,748,682)	(2,796,463)				
Closing Net PP&E	**27,281,803**	**29,252,863**	-	-	-	-
MIFRS						
Opening Net PP&E	28,170,052	27,281,803				
Additions	1,860,433	4,494,747				
Depreciations	(2,748,682)	(1,139,102)				
Closing Net PP&E	**27,281,803**	**30,637,448**	-	-	-	-
Difference in Closing Net PP&E	-	(1,384,586)				
****Adjustment to 2012 Rate Base**						
PP&E Deferral Account Under MIFRS						
Opening Balance		-	**(1,384,586)**	**(1,038,439)**	**(692,293)**	**(346,146)**
Amount added in the Year		(1,384,586)	-			
		(1,384,586)	(1,384,586)	(1,038,439)	(692,293)	(346,146)
Amortize Amount in Deferral Account over 4 Years		-	346,146	346,146	346,146	346,146
Closing Balance	-	**(1,384,586)**	**(1,038,439)**	**(692,293)**	**(346,146)**	-
Effect on Revenue Requirement of Including Deferral Account Amortization in 2012						
Amortization of deferral Account			346,146			
Return on Rate Base -6.91%			95,675			
Amount included in 2012 Revenue Requirement			**441,821**			

c) Please refer to response to part b).

d) Please refer to response to part b).

e) Please refer to response to part b).

Smart Meters

49.

Reference: Exhibit 9 / 4 / 1; Board Decision with Reasons, "Combined Smart Meter Proceeding", Appendix A, August 7, 2007 [EB-2007-0063]

a) Please confirm that HHHI's costs recorded in Account 1555 and Account 1556 are directly related to the smart meter program and are incremental costs. If this is not the case, please explain.

b) Please confirm that HHHI's costs recorded in Account 1555 and Account 1556 are in accordance with the Board's Decision in the Combined Smart Meter Proceeding, Appendix A.

Response:

a) Confirmed.

b) Confirmed.

50.

References: Exhibit 9 / 4 / 2 / pp. 1-10; Exhibit 9 / 4 / 3 / p. 2; Board Decision 'Combined Smart Meter Proceeding [EB-2007-0063]; Board Guideline 'Smart Meter Funding and Cost Recovery' [G-2008-0002], October 22, 2008

The Board indicated in its Decision in the Combined Smart Meter Proceeding that certain costs that were considered "beyond minimum functionality" in relation to smart metering system costs can be recovered as part of future distribution rates. These costs may include web presentment, Customer Information System integration with the Meter Data Management/Meter Data Repository (MDM/R), consumer education, reengineering business practice and integration with retailers.

a) Please indicate if HHHI has recorded such costs and tracked them in separate sub-accounts of Account 1555 and separate sub-accounts of Account 1556 for capital expenditures and OM&A expenses, respectively. Please provide a breakdown by sub-account. If this is not the case, please explain and update the evidence.

b) Please confirm that HHHI did not include borrowing costs relating to money borrowed to finance smart meter installations, if any, as part of the Smart Meter Capital Account 1555 or Account 1556. Please identify which USoA account, if any, HHHI uses to record the borrowing costs.

c) As per the Board's "Guideline: Smart Meter Funding and Cost Recovery" (G-2008-0002) (the "Guideline"), does HHHI use its normal capitalization

policy for smart meters? If this is not the case, please provide an explanation.

d) Are the stranded meter costs recorded in Account 1555 comprised of the gross costs of the stranded meters, less any capital contributions, less the accumulated depreciation and less any proceeds from the disposition of the meters?

e) Please confirm that HHHI is not recording a return on smart meters in Account 1555 or Account 1556. Otherwise, please provide an explanation.

Response:

a) HHHI incurred costs for functionality beyond the minimum functionality adopted in O.Reg. 425/06 in 2010 in relation to the purchase of 100 remote disconnect smart meters. The remote disconnect smart meters were installed in locations where the access to the meter is difficult and disconnection at the pole is the only appropriate method. The additional cost related to disconnections at the pole far exceed the addition $80.00 per remote disconnect meter and therefore is a prudent cost and should remain included in the recovery calculation.

b) It is confirmed that HHHI did not include borrowing costs relating to money borrowed to finance smart meter installations in Smart Meter Capital Account 1555 or Account 1556.

c) HHHI uses its normal capitalization policy for smart meters.

d) The stranded meter costs recorded in Account 1555 comprised of the gross costs of the stranded meters, less any capital contributions, less the accumulated depreciation. Proceeds from the disposition of the meters were recorded as revenue from scrap sales which is included revenue offset.

e) It is confirmed that HHHI did not record a return on smart meters in Account 1555 or Account 1556.

51.
Reference: Exhibit 9 / Appendix D

Please rerun and submit a revised version of the Smart Meter Model adjusting for the following two matters:

a) It appears the current (and recent models) calculate compounded interest on funding adder revenues. Please revise the model applying simple interest (i.e. interest on the opening monthly balance of the principal only) on funding adder revenues, and
b) Please revise the model to calculate simple interest expense on the opening monthly balance for OM&A and amortization expenses.

Response:

The revised model with the changes required in parts a and b will be provided shortly.

52.
Reference: Exhibit 9 / 4 / 3 / p. 4

Please re-calculate the smart meter disposition rider using the following methodology that is based on the approach approved by the Board in PowerStream's 2010 smart meter application (EB-2010-0209):

(i) Allocate the total revenue requirement for the historical years, as revised per the previous interrogatory, using the following cost allocation methodology:

- Allocate the return (deemed interest plus return on equity) and amortization based on the allocation of Account 1860 in the cost allocation model (CWMC in the cost allocation model)
- Allocate the OM&A based on the number of meters installed for each class
- Allocate PILs based on the revenue requirement allocated to each class before PILs

(ii) Sum the allocated amounts and calculate the percentages of costs allocated to customer rate classes.

(iii) Subtract the revenues generated from the smart meter funding adder from the overall revenue requirement.

(iv) Allocate the amount calculated in part (iii) by using the allocation factors derived in part (ii)

(v) To calculate the smart meter disposition rider, divide the allocated amount by rate class derived in part (iv) by the number of customers in each class, and then divide by 12.

(vi) If the proposed disposition period is greater than 1 year, divide the result of part (v) by the proposed number of years.

Response:

HHHI smart meter disposition rider using methodology that is based on PowerStream's 2010 smart meter application (EB-2010-0209) is presented below in Table OEB 1-23.

Table OEB 1-23 : Smart Meter Rate Rider Methodology

	Amount	Residential	GS<50kW	GS 50-999 kW	GS 1000-4999	Street Light	Sentinel	Unmetered Scattered Load
CWMC	5,214,821	4,414,375	364,546	377,500	58,400	-	-	-
% - Allocation		85%	7%	7%	1%	0%	0%	0%
Deemed Interest	$ 222,469	$ 188,322	$ 15,552	$ 16,105	$ 2,491	$ -	$ -	$ -
Return on Equity	$ 277,002	$ 234,484	$ 19,364	$ 20,052	$ 3,102	$ -	$ -	$ -
Amortization	$ 501,430	$ 424,463	$ 35,053	$ 36,298	$ 5,615	$ -	$ -	$ -
	$ 1,000,901	**$ 847,269**	**$ 69,969**	**$ 72,455**	**$ 11,209**	**$ -**	**$ -**	**$ -**
Number of Meter Installed	21,354	19,726	1,629					
% - Allocation	100%	92%	8%					
OM&A	**$ 1,143,544**	**$ 1,056,312**	**$ 87,232**					
Revenue Requirement before Pils	**$ 2,144,446**	**$ 1,903,581**	**$ 157,201**	**$ 72,455**	**$ 11,209**	**$ -**	**$ -**	**$ -**
Allocation % - Based on Revenue Requirement		89%	7%	3%	1%	0%	0%	0%
Pils	**$ 96,969**	**$ 86,077**	**$ 7,108**	**$ 3,276**	**$ 507**	**$ -**	**$ -**	**$ -**
Total Revenue Requirement	**$ 2,241,414**	**$ 1,989,658**	**$ 164,309**	**$ 75,731**	**$ 11,716**	**$ -**	**$ -**	**$ -**
% Cost Allocated to Customer Class	100%	89%	7%	3%	1%	0%	0%	0%
Funding Adder	-$ 1,070,487							
Smart Meter True-up	$ 1,170,928							
Allocate Smart Meter True Up	$ 1,170,928	$ 1,039,409	$ 85,836	$ 39,563	$ 6,120	$ -	$ -	$ -
Number of Customer in Class	21,542	19,726	1,629	176	12			
Smart Meter Rate Disposition Rider - 4 Year Period		**1.10**	**1.10**	**4.69**	**10.58**			

LRAM & SSM

53.
Reference: Exhibit 10 / 1 / 3 / p. 1

HHHI states that the results for OPA programs in 2010 are estimates, based on the number of installs or on methods of estimating program savings, and will be updated upon publication of the OPA final results which was expected to come in September 2011.

Please provide the final results for the 2010 OPA programs HHHI delivered. If the final results are not available, please indicate when HHHI expects to receive them.

Response:

The final OPA-verified results of the 2010 OPA programs were received via an email to HHHI from LDC support (**LDC.Support@powerauthority.on.ca**) dated September 19, 2011. The final results summary for 2011 OPA programs can be found in Appendix OEB 1-E.

The LRAM claimed by HHH was updated to incorporate the final OPA-verified results of the 2010 OPA programs. All other assumptions and inputs remained unchanged from claim originally filed as Exhibit 10 of HHHI's cost of service application EB-2011-0271.

HHH recommends that its LRAM claim be updated from the original claim of $426,806, to a claim of 383,381, including $17,239 in carrying charges. The requested SSM claim remains at $1,417.

Table OEB 1-24 : Summary of Updated LRAM and SSM

Rate class	Updated LRAM	SSM
Residential	$276,155	($448)
GS < 50 kW	$73,353	$436
GS 50 to 999 kW	$28,060	$1,430
GS 1,000 to 4,999 kW	$5,813	$0
Total	**$383,381**	**$1,417**

The updated two-year rate riders are as follows.

Table OEB 1-25 : Updated Rate Riders

Class	Updated LRAM	Updated carrying charges	SSM	Updated total	Unit	2012 forecasted billed kWh/kW	Updated two year rate rider $/unit
Residential	$261,496	$14,659	($448)	**$275,707**	kWh	210,909,970	**0.0007**
GS<50 kW	$71,782	$1,572	$436	**$73,789**	kWh	51,848,139	**0.0007**
GS 50 - 999 kW	$27,176	$884	$1,430	**$29,490**	kW	326,358	**0.0452**
GS 1,000 - 4,999 kW	$5,688	$125	$0	**$5,813**	kW	281,618	**0.0103**
Total	$366,142	$17,239	$1,417	$384,798			

At a four-digit level of precision, the residential two-year rate rider did not change. The two-year GS < 50 kW rate rider decreased from $0.0010/kWh to $0.0007/kWh. The two-year GS 50-999 kW rate rider decreased from $0.0562/kW to $0.0452/kW and the two-year GS 1,000-4,999 kW rate rider decreased from $0.0190/kW to $0.0103/kW.

54.
Reference: Exhibit 10 / 1 / 3 / p. 1

HHHI notes that the reduction in demand related to its CDM programs has been incorporated into the load forecast for May 1, 2012 onward. It further states however, that energy savings related to OPA programs delivered in 2011 have not been captured.

a) Please confirm that HHHI has not included any losses related to 2011 OPA programs in this LRAM application.

b) If part a) is not confirmed, i.e. if HHHI has included losses attributable to 2011 OPA programs, please discuss the rationale for doing so.

Response:

a) HHHI did not include any losses related to 2011 OPA programs in its LRAM application. HHHI included LRAM claims for revenue losses between 2006 and April 30 2012 for programs launched in 2006, 2007, 2008, 2009, and 2010. Revenues lost in 2011 and between January and April 30 2012 are a result of energy savings from 2006, 2007, 2008, 2009, and 2010 programs that have persisted into 2011 and the first four months of 2012.

b) HHHI did not include any losses related to 2011 OPA programs in its LRAM application.

55.
Reference: Exhibit 10 / 1 / 3 / p. 4 Table 10-4

HHHI provides a table outlining its LRAM amounts by funding source.

a) Please confirm that HHHI has used the most recently published OPA Input Assumptions lists when calculating LRAM for Third Tranche programs.

b) If HHHI has not used the most recently published OPA Input Assumptions list when calculating LRAM for its Third Tranche programs, please discuss the rationale for not doing so.

Response:

a) The most recently published OPA input assumption lists are the 2011 Prescriptive and Quasi-prescriptive OPA Measures and Assumptions lists. HHH used the most recent 2011 Prescriptive and Quasi-prescriptive OPA Measures and Assumptions lists for all measures within its Third Tranche programs, with the exception of an LRAM claim associated with the installation of 250W metal halide bulbs.

b) HHH did not use the most recently published OPA input assumption lists for the LRAM claim associated with the installation of 250W metal halide bulbs since this measure is not included in these lists. The best available input assumptions for 250W metal halide bulbs were used to calculate its LRAM claim. These best available input assumptions were found in the 2008 OEB TRC Input Assumptions List. The total LRAM claim associated with the installation of 250W metal halide bulbs was $421.

56.
Ref: Exhibit 10 / Appendix A 'Third Party Review …'

IndEco notes in its third party review, at p. 6, that that energy savings for measures installed between 2006 and December 31, 2010 were calculated to April 30, 2012.

a) Please confirm that HHHI is requesting recovery of lost revenues estimated to April 30, 2012 for programs started between 2006 and December 31, 2010.

b) If part a) is confirmed, please discuss the rationale for requesting recovery of estimated lost revenues until April 30, 2012 in the absence of verified program results for both the 2011 program year and January 1, 2012 to April 30, 2012.

c) If part a) is confirmed, please provide an updated LRAM amount exclusive of estimated lost revenues past December 31, 2010.

Response:

a) Yes, HHHI is claiming recovery of lost revenues estimated to April 30 2012 for programs started between 2006 and December 31 2010.

b) HHHI is **not** requesting recovery of lost revenue associated with unverified programs delivered in 2011, or unverified programs delivered between January 1 and April 30 2012. The requested lost revenues in 2011 and the first four months of 2012 are associated with verified savings arising from programs that were delivered in 2006, 2007, 2008, 2009, and 2010.

A distinction must be made between lost revenue in 2011 due to programs delivered in 2011, and lost revenue in 2011 due to programs delivered in earlier years. A program will lead to energy savings, and thus lost revenues, that will persist over the lifetime of the program's measures. For example, if a 2006 program consists of a measure with a lifetime of six years, the program will lead to lost revenues each year until the end of 2011. This would be unrelated to lost revenue due to a program delivered in 2011.

Table OEB 1-26 below illustrates the verified results that were used to calculate HHHI's LRAM claim. Note that no programs delivered in 2011 were included in the LRAM claim.

OEB 1-26 : Verified Results

	Lost revenues are requested for the following verified program results:						
Program	2006	2007	2008	2009	2010	2011	Jan - Apr 30, 2012
Programs delivered in 2006	Verified results	Verified results	Verified results	Verified results	Verified results	Verified results	Verified results
Programs delivered in 2007		Verified results	Verified results	Verified results	Verified results	Verified results	Verified results
Programs delivered in 2008			Verified results	Verified results	Verified results	Verified results	Verified results
Programs delivered in 2009				Verified results	Verified results	Verified results	Verified results

c) An LRAM amount exclusive of estimated lost revenues past December 31 2010 is provided in the Table OEB 1-27 below. HHHI feels that this LRAM claim would not be the appropriate claim amount for programs delivered in 2006, 2007, 2008, 2009, and 2010 since lost revenue between January 1, 2011 and April 30, 2012 associated with these programs would be unaccounted for.

Table OEB 1-27 : LRAM Amounts Exclusive of Estimated Loss Revenues

Rate class	**LRAM for the period between January 1 2006 and December 31 2010**
Residential	$229,219
GS < 50 kW	$54,922
GS 50 to 999 kW	$22,972
GS 1,000 to 4,999 kW	$5,685
Total	**$312,798**

Bill Impacts

57.

Reference: Exhibit 8 / Appendix A; Exhibit 9 / 3 / 2 / p. 3

a) HHHI prepared bill impact calculations, in consultation with Board staff, for use in the published Notice of Application that differ from the pre-filed calculations in Exhibit 8 and in the Revenue Requirement Work Form Excel spreadsheet. Please provide documentation of the revised bill impact calculations for a Residential customer using 800 kWh per month and a General Service customer in the 'less than 50 kW' class using 2000 kWh per month.

b) Impact calculations are included for customers outside the size range for the General Service 50 – 999 kW class (calculations for 2000 and 4000 kW customers), and for the General Service 1000 – 4999 kW class (calculations for 6500 kw – 13,900 kW). Please provide impact calculations for customers with 500 and 999 kW at rates in the smaller class, and for customers over a suitable range within the larger class.

c) Impact calculations are provided in the pre-filed evidence only for RPP customers. Please provide a parallel set of calculations for non-RPP customers, by combining the two proposed rate riders that would apply to the non-RPP customers in each class.

Response:

Revised bill impacts will be provided when HHHI updates the revenue requirement (IR # 60) and updated RRWF (IR# 61)

Requests for Accounting Orders

58.
References : Exhibit 1 / 1 / 7; Exhibit 9 / 2 / 3; Exhibit 9 / Appendix C

HHHI is requesting an accounting order to establish a deferral or variance account to track costs incurred in Tier 3 programs prior to Board approval. A prospective budget amount of $1,762,000 is provided in Appendix C "Addendum to Halton Hills CDM Strategy" Table A-2.

a) Please provide the expected timing of expenditures for Board-approved CDM programs and expected timing of Board review (and approval).

b) With reference to Board Frequently-Asked Questions about the Accounting Procedures Handbook, December 23, 2010, # 22, account 1567 appears to meet HHHI's request for approval of an account. Has HHHI reviewed the description of account 1567, and if so, please provide clarification on HHHI's request for approval of an additional account.

Response:

a) HHHI expects to have a decision on Board-approved CDM programs within the first quarter of 2012 with implementation expenditures planned for mid to later 2012 and into 2013.

b) Account 1567 is appropriate to record costs after Board-approval of HHHI's Tier 3 programs. However, there is currently no deferral account appropriate for cost associated with the preparation of an application to the Board for its approval. HHHI is requesting an additional account to track the design and preparation costs and would request an order to transfer these costs to Account 1567 upon approval of the requested Tier 3 CDM programs.

59.

References: Exhibit 1 / 1 / 4 / p. 2; Accounting Procedures Handbook, Frequently Asked Questions about the Handbook, December 23, 2010, #22.

HHHI's request is as follows:

Approval to establish a Deferral and Variance account to track costs incurred in the preparation and implementation of Board-Approved Conservation and Demand Management Programs, prior to Ontario Energy Board approval of said programs.

The Board response to the FAQ states, at p. 25:

The account is Account 1567, Board-Approved CDM Variance Account. A distributor should track its spending for its Board-Approved CDM Programs in this variance account, which should be used to record the difference between the
funding awarded for Board-Approved CDM Programs and the actual spending
incurred for these Programs.

a) Please confirm if HHHI has received Board approval for its CDM Programs which HHHI plans to record in the proposed CDM Variance account.

b) Has HHHI incurred actual spending for these Programs?

Response:

a) HHHI has not yet received Board approval for its proposed Tier 3 CDM Programs. HHHI is currently working with the OPA to ensure the proposed programs are not duplicative of OPA programs. Upon acceptance by the OPA, HHHI will submit the programs to the Board for approval.

b) HHHI has incurred approximately $30,000 in costs to design and prepare the Tier 3 CDM programs for review by the OPA.

Updated Revenue Requirement

60.

Reference: Exhibit 1 / 1 / 4 / p. 1

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed base and service revenue requirements that the applicant wishes to make relative to the original application.

Response:

To be provided shortly.

Updated RRWF

61.

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts, including documentation such as an explanatory note or a Reference to an interrogatory response. (Please show the revisions in the middle column of the applicable worksheets, leaving unchanged the leftward columns labelled 'Initial Application'.)

Response:

To be provided shortly.

APPENDIX OEB 1-A

Halton Hills Hydro Inc.
IFRS - Capitalization Policy

IFRS - Capitalization Policy

Standard: IFRS 1 – Elective Exemption, IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Fair Value vs. Carrying Value as Deemed Cost

Objective:

To determine the policy on initial measurement of property, plant and equipment (PP&E) on the date of transition to IFRS

Background:

Halton Hills Hydro Incorporated ("HHHI") may elect to measure an item of PP&E at its fair value on the date of transition to IFRS. The fair value would then represent deemed cost at that date for purposes of subsequent measurement and amortization ("deemed cost election").

An additional IFRS 1 exemption is available to rate regulated entities. The exemption allows an entity to measure an item of PP&E at its previously recorded carrying value (i.e. net book value) on transition to IFRS. As HHHI's operations are rate regulated, they are eligible to apply this exemption.

If an Elective Exemption with respect to PP&E is not taken, HHHI would have to account for PP&E as if the requirements of IAS 16 had always been applied. This would require retrospective restatements of all PP&E balances in accordance with IFRS.

Considerations:

Retroactive restatements will be onerous and impractical as documentation for historical costs are not available.

The fair value exemption is not allowed by the OEB for rate setting purposes.

Fair values are more costly to obtain.

Electing the IFRS 1 exemption for rate regulated entities is more favourable to HHHI. Regulated Net Book Value as at the date of transition to IFRS would be used for rate setting purposes. The OEB requires the use of regulated NBV as

the basis for setting the opening rate base values upon transition to IFRS. Therefore, using the carrying value as deemed cost exemption would more closely align financial reporting with the basis in which regulated cash flows and income are determined by the regulator.

Conclusion:

HHHI has concluded that it will elect the IFRS 1 Exemption for rate regulated entities and use net book value as at date of transition to IFRS (January 1, 2012) as deemed cost.

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment – Measurement after Recognition

Objective:

To determine the policy on measurement of property, plant and equipment (PP&E) after initial recognition

Background:

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E.

Cost Model

After recognition as an asset, an item of PP&E shall be carried at its cost less any accumulated depreciation and any accumulated impairment losses.

Revaluation Model

After recognition as an asset, an item of PP&E whose fair value can be measured reliably shall be carried at a revalued amount, being its fair value at the date of the revaluation less any subsequent accumulated depreciation and subsequent accumulated impairment losses. IAS 16 defines fair value as “the amount for which an asset could be exchanged between knowledgeable, willing parties in an arm’s length transaction.” It also mentions that, if there is no market-based evidence of fair value because of the specialized nature of a particular PP&E item and the item is rarely sold (except as part of a continuing business), an entity may need to estimate fair value using an income or a depreciated replacement cost approach.

Revaluation shall be made with sufficient regularity to ensure that the carrying amount does not differ materially from that which would be determined using fair

value at the end of the reporting period. If an item of PP&E is revalued, the entire class of PP&E to which that asset belongs shall be revalued.

Ontario Energy Board

In its report of the Board on Transition to International Financial Reporting Standards, the OEB will require the use of historical acquisition cost as the basis for reporting PP&E for regulatory purposes.

Conclusion:

HHHI has concluded that it will choose the Cost Model to measure PP&E after initial recognition under IFRS.

Standard: IAS 16 – Property, Plant and Equipment

Topic: Componentization and Depreciation

Objective:

To document the accounting policy on componentization and depreciation of property, plant and equipment.

Background:

Each part of an item of property, plant and equipment (PP&E) with a cost that is significant in relation to the total cost of the item shall be depreciated separately.

An entity should allocate the amount initially recognized in respect of an item of PPE to its significant parts to be depreciated separately.

A significant part of an item of PP&E may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.

Depreciation is to be computed on a systematic basis over the estimated useful life of the item of PP&E. The depreciable amount of an asset is determined after deducting its residual value. In practice, the residual value of an asset is often insignificant and therefore immaterial in the calculation of the depreciable amount.

The residual value and the useful life of an asset shall be reviewed at least at each financial year-end and, if expectations differ from previous estimates, the change(s) shall be accounted for as a change in an accounting estimate in accordance with **IAS 8** *Accounting Policies, Changes in Accounting Estimates and Errors.*

Depreciation of an asset begins when it is available for use (i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended by management). Depreciation of an asset ceases at the earlier of the date that the asset is classified as held for sale in accordance with **IFRS 5** and the date that the asset is derecognized.

Considerations:

Significant components of PP&E will be separately accounted under IFRS. Each significant component and the estimated useful lives, for purposes of computing depreciation expense under IFRS, will be set out in Table 1 as attached.

Overhead system

The following components have been identified – poles, conductors, transformers, switches, municipal substations comprised of DC service station, switchgear, and transformer.

Poles

HHHI has wood, steel and composite poles. HHHI has 8,000 poles of which 10 are composite, 1 is
useful lives of the cross-arms and insulators are consistent with the pole. Insulators may be changed more frequently, however the cost in comparison to the cost of a pole is insignificant. Therefore, brackets, cross-arms and insulators will have the same useful lives as the pole and will be included as a fully dressed pole.

Engineering will test the condition of the pole rather than the age when determining if a pole should be changed. Engineering have preliminarily determined the average life of poles in the system to be approximately 60 years, while the Kinectrics Inc. Report No: K-418022-RA0001-R003, dated December 10, 2009 (HHHI Kinectrics report) shows a maximum life of 50 years. However, the study was commissioned before HHHI had any asset management initiatives and the results of the current pole testing shows that poles are requiring changing at an approximate age of 40-45 years. Therefore, a useful life of 50 years is reasonable.

Conductor

The HHHI Kinectrics report reflects a useful life between 50-77 years, with a typical useful life of 60 years based on moderate mechanical stress, low electrical loading and moderate environmental factors. Conductor in the system is under moderate mechanical stress and moderate electrical loading which suggests that useful life is lower than typical. On average, the change of pole dictates the change of conductor. Load growth also dictates the change in

conductor. As a result, a useful life of 50 years will be used which is consistent with the useful life of the poles.

Transformer

Pole mounted transformers typically have a different useful life than the pole and conductor. When a pole is removed along with a pole mounted transformer, the transformer could be sent in for service and re-used at a future date. The transformer is a significant component of PP&E and the transformer could have a different useful life than the pole. Therefore, transformers will be a separate component and will be categorized between pad mounted transformers and overhead transformers.

The HHHI Kinectrics report reflects a useful life between 30-60 years, with a typical useful life of 40 years based on moderate electrical loading and environmental factors. HHHI has moderate electrical loading and moderate environmental conditions which would trend towards the typical life as the useful life of the transformer. Therefore, the typical useful life of 40 years is to be used for transformers.

Switches

The majority of the switches in use today by HHHI are manual overhead switches. HHHI's capital plan includes the installation of remote automated switches. A separate component for local motorized switches is not required as most switches will be automated and remote going forward. Automated switches are currently segregated in the capital budget by switch ($30,000), motor and RTU ($10,000). Therefore, all the pieces of automated switches are to be kept together, and all switches (fuse cut-outs, overhead switches and remote automated) are to be included as one component – overhead devices. HHHI has fuse cut-outs which are transformer switches. These items have a low dollar value ($100-$150).

The HHHI Kinectrics report reflects a useful life between 30-60 years, with a typical useful life of 50 years. Switch maintenance practices at HHHI are low; therefore life should be closer to the minimum identified in the HHHI Kinectrics report rather than the typical useful life. Over the past 35 years, only a few switches have needed to be replaced. The ages of these switches are approximately 40 years old. There are some cut-out switches that are only 10-15 year old; however these are small dollar value ($150 each). Therefore, the useful life of 40 years is to be used.

Voltage Regulator

The useful life of the voltage regulator is the same as the transformer. Therefore, there is no need to keep a separate component for the voltage regulators.

Reclosers

Reclosers are a type of switch and are currently included in devices and do not need to be separated from switches due to lack of significance in dollar value.

Municipal Substations

HHHI currently has 11 outdoor municipal substations and 1 indoor municipal substation. There is a high dollar value in the substations with the majority of the cost relating to the transformer with minor costs relating to fencing and building. Based on HHHI's experience, the tap changer is most likely to be replaced before the winding. The tap changer is a significant cost to replace although the majority of the cost is in the transformer itself. The building and fencing do not have a large dollar value in relation to each other. Therefore, all parts of the building (building and fence) for the municipal substation should be grouped together with the power transformer being one component comprised of the transformer, winding and tap changer.

The HHHI Kinectrics report shows a useful life of 32-55 years, with a typical useful life of 45 based on moderate electrical loading and environmental factors and low operating and maintenance practices. HHHI operating and maintenance are low. Engineering is finding that after 17-30 years of age maintenance costs increase. HHHI environmental factor would be a little higher than moderate as only one out of twelve municipal substations is indoor. Therefore the useful life should be lower than typical and a useful life of 35 years would be reasonable.

DC Service Station

The DC station service asset class includes battery banks and chargers. Based on HHHI's experience, batteries do not last as long as chargers. According to the HHHI Kinectrics report the battery and chargers have similar useful lives. Therefore, DC Station service will be one component comprising the battery and charger.

The HHHI Kinectrics report shows a useful life of 10-30 years, with a typical useful life of 20 years, based on moderate electrical loading, low environmental factors and moderate maintenance practices and moderate non-physical factors. For HHHI, the non-physical factors (technology) are low and environmental factors are also low as DC systems are indoors. A useful life of 20 years is typical of the charger (battery depends on the technology and normally does not last longer than charger). Therefore the useful life of 20 years would be reasonable.

Switchgear

HHHI operates with both air and gas insulated switchgear. As required, the air insulated switchgear is replaced with the latest design of metalclad gas insulated switchgear. The useful life expected by HHHI is the same which is supported by the lives identified in the HHHI Kinectrics report. The HHHI Kinectrics report has been broken out by type of switchgear – air vs. gas. When the switchgear

requires replacement, HHHI typically replaces the whole switchgear, not just the parts within the switchgear. Therefore, the switchgear assembly should continue to be combined into one component – switchgear; and the type - air and gas switchgear should be grouped together as one component.

Kinectrics shows a useful life between 30-60 years, with a typical useful life of 40 years based on low electrical loading, moderate environmental factors, and operating and maintenance practices. Typical useful life of 40 years is accurate according to engineering. Electrical loading in the system is high and environmental factors are low as switchgear is all indoor. These factors offset each other. Experience of one engineer reveals that they have seen only one switchgear (air or gas) replaced which had an approximate 40 year useful life. Therefore, a useful life of 40 years is reasonable.

Station Grounding Systems

HHHI will replace the grounding system when the transformer is replaced. Therefore, the station grounding system will continue to be grouped together with transformers.

Underground System

The following possible components were identified – primary cable, secondary cable, transformers, switchgear, utility chamber, ducts, transformer switchgear foundation, junction cubicle, SCADA, fault indicator, metering, and smart meters.

Underground Primary Cable

HHHI utilizes only TRXLP cable within its underground distribution system. HHHI stopped direct burying cables approximately 20-25 years ago. The net book value of direct buried cable is expected to be nil. All new underground primary cable is installed – encased in duct or concrete. Based on HHHI's experience, induct and concrete have the same useful life. Arrestors and terminations are an insignificant part of the cost of the underground network and have a life similar to that of the cable. Therefore arrestors, terminations and elbows will be grouped together as one component in underground primary cable.

The HHHI Kinetrics report identified the useful life of underground primary cable including termination, arrestors, utility chambers and elbows of 40-60 years, with a typical useful life of 40 years based on moderate mechanical stress, electrical loading and environmental factors. Experience has shown cable does not require change out before 40 years; therefore a 40 year useful life is reasonable.

Secondary Cable

HHHI has both induct and direct buried secondary cable. All new underground secondary cable installed is encased in duct or concrete. HHHI does not have

any PI and PIJ cables. Therefore, induct and direct buried cables will be grouped together.

The HHHI Kinectrics report identifies a useful life between 40-60 years, with minimum and typical useful life at 40 years. This is based on moderate mechanical stress, electrical loading and environmental factors. A useful life of 40 years is appropriate as normally change of secondary cables is due to electrical loading issues rather than failure and experience shows secondary cables are not changed out before then. Therefore, a useful life of 40 years is appropriate.

Transformers

Transformers are a significant part of the underground system.

The HHHI Kinectrics report reflects the useful life between 30-40 years, with a typical life of 40 years based on low mechanical stress and moderate electrical loading and environmental factors. HHHI has low electrical loading in their underground system which would put the useful life towards the maximum which is the same as typical. A useful life of 40 years is therefore appropriate.

Pad Mounted Switchgear

HHHI operates with both air and gas insulated switchgear. Experience has indicated that both air and gas switchgear have the same useful lives and this is supported by the HHHI Kinectrics report.

The HHHI Kinectrics report indentifed the useful life between 20-40 years, with a typical useful life of 30 years based on low mechanical stress and electrical loading and high environmental factors. Environmental factor is high as the assets tend to rust as they sit at the side of the road, so the snow, debris, salt, etc. factor into the condition of the asset. The approximate age is 25 to 30 years; therefore a 30 year useful life is appropriate.

Utility Chamber

The Utility Chamber facilitates cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. HHHI currently has two utility chambers and has typically experienced that these chambers have a similar useful life to the conductor. Utility chambers are expensive to install, but they last a long time. Therefore, utility chambers are to be grouped with underground primary cable.

Ducts

The HHHI Kinectrics report shows a useful life from 30-80 years, with a typical useful life of 50 years based on high mechanical stress and moderate environmental factors. In HHHI's system, mechanical stress is not high and ducts underground are normally concrete encased and are therefore protected. They

should therefore have a higher life than underground cable and a useful life of 50 years is reasonable.

Transformer and Switchgear Foundation

The transformer and switchgear foundation asset class is similar to the utility chamber asset. It is a buried precast concrete vault on which the pad-mounted transformers or switchgear are mounted. Typically the foundation is buried and the top portion is above ground. The transformer switchgear foundation is usually installed when the duct is installed. Therefore, duct and transformer switchgear foundation are to be grouped together.

Junction Cubicle

Junction cubicle is similar to switchgear but it is less expensive. According to the HHHI Kinectrics report, junction cubicle and switchgear useful lives are similar. As such, junction cubicle is to be grouped with the pad mounted switchgear.

SCADA

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote units (RTUs) allow the SCADA system to communicate with field equipment. The RTU is typically comprised of power supply, CPU, I/O Modules, housing and chassis, communications interface and software.

The HHHI Kinectrics report identifies a SCADA useful life between 5-30 years, with a typical useful life of 20 years based on low environmental and maintenance practices and high non-physical factors. For HHHI, the environmental and maintenance factors are low. The non-physical factor is high as SCADA is technology-based. The life of SCADA equipment is limited by technology. Therefore a 20 year useful life is appropriate based on non-physical.

Fault Indicator

HHHI has approximately 45 fault indicators comprised of both overhead and underground. The cost of a fault indicator is approximately $200-500. Overhead fault indicators should be grouped with overhead conductor and underground fault indicators are used with transformers and should be grouped with the underground transformers.

Metering

The metering asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT

HHHI typically recalibrates industrial/commercial meters every 10 years. As industrial and wholesale meters last the same amount of time, they will be grouped together.

The HHHI Kinectrics report shows a useful life range of industrial/commercial type meters between 20 -60 years. The non-physical factors are high due to technology and life is limited by technology. A 20 year useful life is reasonable.

Rarely, is HHHI required to replace CTs and PTs; only if they are hit by lightning or other electrical issues. CTs and PTs last a lot longer than a meter. As a result, CTs and PTs should be segregated from industrial and wholesale meters.

The HHHI Kinectrics report shows a useful life between 35-50 years, with a typical useful life of 45 years based on low maintenance. CTs & PTs typically last about 45 years. Useful life of 45 years will be used.

Smart Meters

A smart meter is an advanced meter, essentially an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via repeaters and collectors back to the local utility. HHHI expects that repeaters, antennas and data connectors would easily last as long as the meters, but they are based on technology and this impacts their useful life as these are communication based. Smart metering is a 20 year plan. Cost information should be kept in as much detail as in the Kinectrics chart – smart meters, repeaters, data concentrators.

The HHHI Kinectrics report reflects a minimum life for all smart meters of 15 years to be deemed appropriate as this is new technology with no history. Technology is considered to be a life limiting factor.

Minor Assets

With reference to the HHHI Kinectrics report:

1. Vehicles will be separated into the following categories and useful lives will be based on HHHI replacement policy as follows:
   - bucket trucks, useful life of 12 years
   - trailers, useful life of 15 years and
   - Vans/cars/light vehicles, useful life of 8 years.

2. Office equipment - a 5 year useful life.

3. Computer hardware and software is technology driven. The life is determined to be 3 years and 2 years respectively.

4. Tools, shop, garage equipment and measurement & testing equipment are to be bundled together and useful life is determined to be 10 years.

5. Stores equipment with useful life of 10 years.

6. Communication equipment including vehicle radio will continue to use the current useful life of 10 years.

Conclusion:

The new levels of componentization and the corresponding useful lives will be applied beginning January 1, 2012. The net book value as deemed cost exemption (available to rate regulated entities) will be applied so that the opening values at January 1, 2012 do not need to be restated and therefore, componentization does not need to be applied retroactively.

Table 1: HHHI – PP&E Components and Estimated Useful Lives

Component	Previous Component	Proposed Useful Life	Existing Useful Life
Land	Land	N/A	N/A
Overhead poles, fully dressed	Overhead Poles	50	25
Overhead conductors	Overhead Conductors & Devices	50	25
Overhead line switches, reclosures, fault circuit indicators	Overhead Conductors & Devices	40	25
Municipal substations – transformers incl grounding system	MS Station equipment	35	25
Municipal substations - DC service station incl battery & chargers	MS Station equipment	20	25
M.S. Switchgear	Overhead Conductors & Devices	40	10
Underground primary cable incl utility chambers	Underground Conductors & Devices	40	25
Underground secondary cable	Underground Services	40	25
Underground ducts and transformer switchgear foundation	Underground Conduit	50	25
Overhead transformers incl voltage regulator	Overhead Transformers	40	25
Underground transformers incl fault indicators	Underground Transformers	40	10

Underground switchgear and junction cubicle		30	-
SCADA – battery, RTU, relay, IED		20	15
Industrial/Commercial, wholesale Energy Meters	Interval Meters – 1 Phase, 3 Phase & Meters YE Adj	20	25
PTs & CTs	Meters	45	25
Smart meters - meters	Meters	15	15
Smart meters - repeaters	Meters	15	15
Smart meters – data concentrators	Meters	15	15
Office Furniture and Equipment	Office Furniture and Equipment	5	10
Computer Equipment Hardware	Computer Equipment Hardware	3	5
Computer Software	Computer Software	2	1
Vehicles – bucket trucks	Transportation Equipment	12	5
Vehicles – trailers	Transportation Equipment	15	5
Vehicles – vans/cars	Transportation Equipment	8	5
Tools, Garage Equipment, Measurement & Testing Equipment	Tools, Garage Equipment, Measurement & Testing Equipment	10	10
Stores Equipment	Stores Equipment	10	10
Wireless Communication	Communication Equipment	10	-

Standard: IAS 16 – Property, Plant and Equipment

Topic: Capitalization - Burdens

Objective:

To document the accounting policy on the capitalization of burdens.

HHHI will capitalize all costs, including the above burdens, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management.

Any general and administrative costs currently included in the various burden rates under CGAPP will not be capitalized under IFRS.

The following changes were made to the capitalization policy as a result of the transition to IFRS.

Payroll allocation

The following accounts were removed from this allocation as they are not directly attributable to an asset:

- Non-Productive Time (account 670-14-21)
- Major Tools Amortization (account 670-14-22)
- Payroll Overhead Management Cost (account 670-26-13/14/15/17)
- MEARIE – Total Benefits (account 670-26-26)
- Department/ OH Recovery (account 670-90-89)

Stores Allocation (Materials Burden)

No changes were identified for this allocation.

Rolling Stock (Vehicle Burden):

No changes were identified for this allocation.

Standard: IAS 16 – Property, Plant and Equipment

Topic: Property, Plant and Equipment Derecognition of PP&E

Objective:

To document the accounting policy on derecognition of property, plant and equipment.

Background:

The carrying amount of an item of property, plant and equipment (PP&E) shall be derecognized:

(a) On disposal; or

(b) When no future economic benefits are expected from its use or disposal (eg. the item is removed from use).

When a part of an item of PP&E is replaced and that replacement is capitalized under the recognition principle in IAS 16, then the replaced part is derecognized regardless of whether the replaced part has been identified as a separate component and depreciated separately.

The gain or loss arising from the derecognition of an item of PP&E shall be included in profit or loss when the item is derecognized. Gains shall not be classified as revenue, and instead should be presented as other income or expense.

The disposal of an item of PP&E may occur in a variety of ways (e.g. by sale, by entering into a finance lease, by donation, etc.) In determining the date of disposal of an item, an entity applies the criteria in IAS 18 for recognizing revenue from the sale of goods. Under IAS 18.14, revenue from the sale of goods shall be recognized when all the following conditions have been satisfied:

(a) The entity has transferred to the buyer the significant risks and rewards of ownership of the goods

(b) The entity retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the goods sold;

(c) The amount of revenue can be measured reliably;

(d) It is probable that the economic benefits associated with the transition will flow to the entity; and

(e) The costs incurred or to be incurred in respect of the transactions can be measure reliably.

The gain or loss arising from derecognizing of an item of PP&E shall be determined as the difference between the net disposal proceeds, if any, and the carrying amount of the item.

Considerations:

Currently the pooled method of accounting for capital assets for Utility companies is applied and is an approved method by the Ontario Energy Board (“OEB”).

The pooled method of accounting, pools like assets together based on the year of addition as the pooling method assumes that each asset will last, on average, their full useful life

Under the pooled method there is an assumption that there are assets within the same asset pool which will last longer or shorter than the estimated useful life and therefore, in the end everything balances out on average. However, the assumption does not always hold true, especially if assets are removed from service before the end of their useful life, for example, when a road is widened and a pole line relocated.

Under the pooled method, if an asset is removed from service prior to the end of its useful life, there is no change to the accounting to remove the asset – it remains in the GL (ie it is not derecognized).

Currently, HHHI records their capital assets using the pooling method of accounting and does not derecognize assets removed from service prior to the end of their useful life.

Since HHHI removes assets from service prior to the end of their useful life from time to time, these removed assets should be derecognized. HHHI must derecognize the cost of the asset which was removed/disposed. A write-off would be recorded in the amount of the remaining NBV of the asset removed/disposed. Any proceeds on the disposal of the asset would offset the write-off.

Conclusion:

In order to properly account for assets that are removed from service in the accounting records, a collaborative process needs to be developed involving Engineering, Operations and Finance which alerts the accounting department when an asset has been removed from service in order to write-off the asset (long-term issue)

If a project include only the addition of a new asset, without any removal of old assets, then there are no de-recognition losses to record.

Standard: IAS 23 – Borrowing Costs

Topic: Borrowing Costs – Property, Plant and Equipment

Objective:

To determine the policy on accounting for borrowing costs for property, plant and equipment.

Background:

Borrowing costs are interest and other costs that an entity incurs in connection with the borrowing of funds. A qualifying asset is an asset that necessarily takes a substantial period of time to get ready for its intended use or sale. A substantial period of time is not defined in the IAS standard. Guidance provided by KPMG (Insights) suggests that a substantial period of time would be considered to be a period well in excess of 6 months.

For all subsequent periods following the initial recognition of an asset, IAS 16 permits a choice of using either the cost model or the revaluation model for valuing PP&E. HHHI has chosen to use the cost model in accordance with OEB requirements.

IAS 23 requires that borrowing costs be expensed as they are incurred unless they relate to "qualifying assets", in which case they must be capitalized if certain conditions are met. When interest is capitalized, IAS 23 requires the following steps:

- Begin capitalization when borrowing costs are incurred and expenditures and activities to develop a qualifying asset are in progress;
- Suspend capitalization when development is interrupted for extended periods; and
- Cease capitalization when a qualifying asset is ready for its intended use or sale.

Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. All other borrowing costs are recognized as interest expense.

The borrowing costs capitalized must reflect the weighted average of the actual borrowing costs incurred. The OEB requires the actual interest rate on the debt to be used if the related debt was acquired on an arm's length basis. If the debt is acquired on a non-arm's length basis then the interest rate used cannot exceed the Board's published rates for CWIP.

Definitions:

Qualifying asset – HHHI defines a qualifying asset as one that takes in excess of 9 months to construct or get ready for its intended use.

Conclusion:

Eligible borrowing costs will be capitalized as part of PP&E for all qualifying assets. Interest rate to be used for capitalization will be limited to the OEB's published rate for CWIP for regulatory reporting purposes.

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

APPENDIX OEB 1-C

Dion Durrell

SECTION E
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of Halton Hills Hydro Inc.
Actuarial Valuation as at January 1, 2009

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of Halton Hills Hydro Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation;

ii) the membership data summarized in Section B is accurate and complete; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on January 1, 2009.

HALTON HILLS HYDRO INC.

10/09/30
Date

Signature

DAVID J. SMELSKY
Name

CHIEF FINANCIAL OFFICER
Title

APPENDIX OEB 1-D

9/8/2011

Halton Hills Hydro Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.25%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed increase in Employer Contributions	actual	expected*
A. Determination of Benefit Expense		
Current Service Cost	10,525	12,876
Interest on Benefits	20,176	20,815
Expected Interest on Assets	-	-
Past Service Cost	(8,582)	(8,582)
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	(8,834)	(5,390)
Benefit Expense	13,284	19,719
B. Reconciliation of Prepaid Benefit Asset (Liability)		
Accrued Benefit Obligation (ABO) as at December 31	373,092	391,745
Assets as at December 31	-	-
Unfunded ABO	(373,092)	(391,745)
Unrecognized Loss/(Gain)	(59,292)	(53,902)
Unrecognized Past Service Cost	(51,490)	(42,909)
Prepaid Benefit Asset (Liability)	(483,875)	(488,555)
Prepaid Benefit/(Liability) as at January 1	(486,146)	(483,875)
Benefit Income/(Expense)	(13,284)	(19,719)
Contributions/Benefit Payments by the Employer	15,556	15,038
Prepaid Benefit Asset (Liability)	(483,875)	(488,555)

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. Significant changes in 2010 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

9/8/2011

Halton Hills Hydro Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.25%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed increase in Employer Contributions	actual	expected*
C. Calculation of Component Items		
Calculation of the Service Cost		
- Current service cost	10,525	12,876
Interest on Benefits		
- ABO at January 1	320,062	373,092
- Current service cost	10,525	12,876
- Benefit payments	(7,778)	(7,519)
- Accrued benefits	322,809	378,449
- Interest	20,176	20,815
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	7,778	7,519
- Benefit payments	(7,778)	(7,519)
- Expected assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	320,062	373,092
- Current service cost	10,525	12,876
- Interest on benefits	20,176	20,815
- Benefit payments	(15,556)	(15,038)
- Expected ABO at December 31	335,207	391,745
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	15,556	15,038
- Interest on assets	-	-
- Benefit payments	(15,556)	(15,038)
- Expected Assets at December 31	-	-

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. Significant changes in 2010 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

9/8/2011

Halton Hills Hydro Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2009	Projected Calendar Year 2010
Discount Rate - January 1	6.25%	5.50%
Discount Rate - December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed increase in Employer Contributions	actual	expected*
D. Actuarial (Gain)/Loss		
(Gain)/Loss on ABO as at January 1		
- Prepaid Benefit/(Liability) as at January 1	486,146	483,875
- Unamortized Past Service (Gain)/Loss	(60,072)	(51,490)
- Unamortized (Gain)/Loss	7,743	(59,292)
- Expected ABO	433,817	373,092
- Actual ABO	320,062	373,092
- Total (Gain)/Loss on ABO	(113,755)	-
(Gain)/Loss on assets as at January 1		
- Expected assets	-	-
- Actual assets	-	-
- (Gain)/Loss on assets	-	-
Total (Gain)/Loss as at January 1	(106,012)	(59,292)
10% of ABO as at January 1	32,006	37,309
Total (Gain)/Loss in excess of 10%	(74,006)	(21,983)
Expected average remaining service life (years)	12	11
Minimum Amortization for current year	(6,167)	(1,998)
Actual Amortization for current year	(8,834)	(5,390)
(Gain)/Loss on ABO at December 31 due to change in discount rate assumption		
- Expected ABO - December 31	335,207	
- Actual ABO - December 31	373,092	
- (Gain)/Loss on ABO at December 31	37,886	
Unamortized (Gain)/Loss	(59,292)	(53,902)

* based on estimated employer benefit payments for those expected to be eligible for benefits.

Projected calendar year 2010 results are provided for informational purposes only. Significant changes in 2010 such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require a full actuarial review.

APPENDIX OEB 1-E

2010 Final CDM Results: Summary

LDC: Halton Hills Hydro Inc.

This report provides an estimated allocation of 2010 OPA-funded conservation and demand management (CDM) program results for each LDC's service territory. A full, detailed report will be available in late September/early October.

The results provided in this report are in accordance with OPA practices and policies for reporting. Demand Response initiatives, for example, have been reported based on the total DR resources that were available (based on contracted nameplate capacity) rather than the actual demand reduction which occurred at the one-hour system peak in a given year.

The OPA welcomes inquiries regarding the determination of these province-wide CDM program results and/or allocation of these results to individual LDC territories. Please direct any questions to ldc.support@powerauthority.on.ca. The OPA is unable to provide any technical or regulatory advice to LDCs regarding specific treatment of these OPA-funded CDM program savings for the purposes of Lost Revenue Adjustment Mechanism or other filings by LDCs to the OEB. Such inquiries should be directed to the OEB.

All results are incremental savings in 2010 presented at the end-user level

Program	Initiative	Activity Unit	Halton Hills Hydro Inc.					Province-Wide				
			Activity Level	Net Summer Peak Demand Savings (MW)	Net Energy Savings (MWh)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Activity Level	Net Summer Peak Demand Savings (MW)	Net Energy Savings (MWh)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)
Consumer	Cool Savings Rebate	Rebates	634	0.10	151	0.22	351	136,626	20.22	31,117	46.01	72,821
Consumer	Every Kilowatt Counts Power Savings Event	Products purchased	3,390	0.01	106	0.02	228	613,248	1.70	19,100	4.00	41,300
Consumer	Great Refrigerator Roundup	Appliances	289	0.02	168	0.05	316	67,822	5.96	39,290	11.64	73,912
Consumer	***peaksaver®***	Devices installed	0	0.00	0	0.00	0	36,507	20.44	81	22.49	89
Business	Toronto Comprehensive	Projects	0	0.00	0	0.00	0	730	17.70	114,600	37.50	281,200
Business	Electricity Retrofit Incentive Program	Projects	4	0.05	285	0.10	562	1,532	19.80	111,740	37.82	220,230
Business	High Performance New Construction*	Projects	1	0.05	109	0.07	155	288	12.91	29,433	18.44	42,048
Business	Hydro Ottawa ***peaksaver®*** Small Commercial Pilot	Devices installed	0	0.00	0	0.00	0	939	0.80	2,500	0.88	2,750
Business	Multifamily Energy Efficiency Rebates	Projects	4	0.02	244	0.03	332	970	4.55	53,700	5.95	72,900
Business	***peaksaver®***	Devices installed	0	0.00	0	0.00	0	243	0.09	2	0.17	2
Business	Power Savings Blitz	Projects	225	0.20	601	0.20	603	48,274	42.20	129,200	42.60	129,500
Business, Industrial	Demand Response 3	Facilities	1	0.93	18	0.93	18	246	251.70	4,932	251.70	4,932
Business, Industrial	Loblaw & York Region Demand Response*	Facilities	0	0.11	0	0.11	0	2	29.21	0	29.21	0
Industrial	Demand Response 2	Facilities	0	0.44	514	0.44	514	3	119.00	139,100	119.00	139,100
Total				**1.9**	**2,196**	**2.2**	**3,079**		**546.3**	**674,795**	**627.4**	**1,080,783**

Program	Initiative	Allocation Methodology	Notes
Consumer	Cool Savings Rebate	Actual LDC specific results	
Consumer	Every Kilowatt Counts Power Savings Event	Measure level allocation based on 2010 Residential Energy Throughput	
Consumer	Great Refrigerator Roundup	Actual LDC specific results	
Consumer	***peaksaver®***	Actual LDC specific results	
Business	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Ltd. service territory	
Business	Electricity Retrofit Incentive Program	LDC's respective proportion of province-wide reported gross demand savings.	
Business	High Performance New Construction	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	Evaluation not yet complete; Updates expected in October/November
Business	Hydro Ottawa ***peaksaver®*** Small Commercial Pilot	Program run exclusively in Hydro Ottawa service territory	
Business	Multifamily Energy Efficiency Rebates	LDC's respective proportion of province-wide reported gross demand savings.	
Business	***peaksaver®***	Actual LDC specific results	
Business	Power Savings Blitz	LDC's respective proportion of province-wide reported gross demand savings.	
Industrial	Demand Response 2	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	1) Although the program is managed internally and actual participant data is available, the small participant population can lead to participant confidentiality issues if disclosed on an actual LDC share basis. 2) Program results are based on contracted nameplate capacity at the end of the calendar year and not actual summer coincident peak demand reduction.
Business, Industrial	Demand Response 3	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	
Business, Industrial	Loblaw & York Region Demand Response*	Initiative level allocation based on 2010 non-residential energy throughput by LDCs	

** Initiative is not evaluated*