Board Staff

Cross Examination Compendium

EB-2011-0054

2. RATE BASE

Issue 2.2 - Is the working capital allowance for the test year appropriate?

<u>Board Staff Question 9 - Ref: Exh B4-2-1, p20</u>

The current WCA, as approved in the last cost of service proceeding, is 12.5%. Hydro Ottawa has filed a lead-lag study to support a proposed WCA of 14.2%. The evidence states that no impact of TOU rates has been considered. Please explain what consideration the lead-lag study gives to smart meters and remote reading capability.

Response

Please note the 12.5% WCA approved in Hydro Ottawa Limited's ("Hydro Ottawa") 2008 cost of service proceeding was not based on Hydro Ottawa specific data but rather on the results of a lead-lag study conducted by Toronto Hydro-Electric System Limited for its 2008 test year.

The lead-lag study did not make any considerations for smart meters and remote reading capability. Hydro Ottawa's bills are produced once the spot market price is available (10 business days after the service period end date), even for those that are on the fixed regulated price plan. The system needs to calculate the difference between what would have been billed at the spot market price and what was billed at the fixed rate for the purposes of filing claims with the Independent Electricity System Operation ("IESO") each month. The method in which meter reading data is gathered has not changed Hydro Ottawa's billing process.

No capital additions have been included in the 2012 rate application to support a change to the billing system or to maintain appropriate data to submit claims to the IESO related to billing customers prior to receiving the spot market price.

NAVIGANT

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June 3, 2011

Ms. Jane Scott
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Sent by e:mail: janescott@hydroottawa.com

Dear Ms. Scott:

Navigant was retained by Hydro Ottawa Limited ("HOL" or "the Company") to perform an independent review of its lead lag study supporting its request for a working capital allowance from the Ontario Energy Board ("OEB" or "the Board"). The purpose of this letter is to present the results of our review of HOL's analysis on working capital requirements dated June 2011.

Based on our review, we conclude that the HOL analysis is:

- **Complete**, in terms of revenue and expense items considered.
- Generally **consistent**, in terms of methods used with other studies that have been presented before the OEB by Horizon Utilities ("Horizon"), Hydro One Networks ("HONI") and Toronto Hydro Electric System Limited ("THESL").

Our conclusion therefore, is that the result of HOL's analysis – a request to the Board for 14.2% of Operations, Maintenance, and Administration ("OM&A") expenses including cost of power – is **reasonable** for two reasons: a) it represents a working capital requirement as evidenced by the Company's 2009-10 operations and, b) it is based on a study that is comparable in terms of approach, though not necessarily its result which by definition is HOL specific, with those supporting other such requests that have been historically accepted by the OEB.

Summary of the HOL Analysis dated June 2011

In its analysis dated June 2011, the Company has identified a working capital requirement of 14.2% of OM&A expenses including cost of power. The approach taken by the Company was to utilize actual experience from 2009 and 2010 in order to determine an average percent of OM&A expense including cost of power represented by working capital. The result, i.e., 14.2%, has then been applied to the Company's 2012 estimate of OM&A expenses including cost of power to determine the amount of working capital to include in its regulated rate-base. The derivation of the 14.2% working capital percentage is shown in Table 1 below.

Table 1: Derivation of the Working Capital Percentage[1]

Line	Description	2009 Revenue Lag Days	2010 Revenue Lag Days	2009 Expense Lead Days	2010 Expense Lead Days	2009 Net Lag (Lead) Days	2010 Net Lag (Lead) Days	2009 Working Capital Factor	2010 Working Capital Factor	2009 Amounts $M	2010 Amounts $M	2009 WCA - $M	2010 WCA - $M
	(A)	(B)	(C)	(D)	(E)	(F) = (B) - (D)	(G) = (C) - (E)	(H) = (F)/365	(I) = (G)/365	(J)	(K)	(L) = (H) X (J)	(M) = (I) X (K)
1	Cost of Power	75.3	75.2	34.0	33.7	41.3	41.6	11.32%	11.39%	588.0	621.5	66.6	70.8
2	OM&A Expenses	75.3	75.2	11.3	11.2	64.0	64.1	17.53%	17.55%	53.8	54.9	9.4	9.6
3	Interest on Long Term Debt	75.3	75.2	45.6	45.6	29.7	29.6	8.12%	8.12%	14.6	15.5	1.2	1.3
4	PILs	75.3	75.2	13.6	(3.3)	61.7	78.6	16.90%	21.52%	13.9	13.8	2.4	3.0
5	Debt Retirement Charges	75.3	75.2	33.8	32.7	41.5	42.6	11.36%	11.66%	52.5	52.7	6.0	6.1
6	HST											5.1	5.5
7	Total											90.6	96.3
8	Average WCA as a % of OM&A Including Cost of Power											14.2%	

The Company has considered its three major sources of revenues in its study: a) from residential and business customers, b) from retailers, and c) from other sources. Considered together and on a dollar-weighted basis, the Company's analysis indicates that the revenue lag is 75.3 days for 2009 and 75.2 days for 2010 respectively. The information is summarized in Table 2 below.

Table 2: Derivation of Overall Revenue Lag Days[2]

Source of Revenues	2010				2009				Weighted Average Days
	Revenue Lag (Days)	Amount $s	Weighting Factor	Weighted Revenue Lag Days	Revenue Lag (Days)	Amount $s	Weighting Factor	Weighted Revenue Lag Days	
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Residential and Business	74.97	770,833,454	98.05%	73.51	74.97	732,196,506	98.42%	73.78	
Retailers	30.15	321,152	0.04%	0.01	32.90	347,827	0.05%	0.02	
Other Sources	90.51	15,016,106	1.91%	1.73	96.16	11,420,912	1.54%	1.48	
Total		786,170,711	100.00%	75.2		743,965,246	100.00%	75.3	
Weighted Average 2009-2010		51.4%		75.2		48.6%		75.3	75.3

The majority of the Company's revenues in 2009 and 2010 were from residential and business customers (98% or more). The average lag time, i.e., the average of 2009 and 2010, associated with the realization of these revenues was 74.97 days consisting of a service lag time of 30.24 days, a billing lag time of 18.17 days, a collections lag time of 25.41 days, and finally, a payment processing lag time of about 1.14 days.

[1] Note that we have not conducted an independent evaluation of the amounts shown in Cols (J) and (K) of Table 1 and as such cannot render an opinion on such amounts.

[2] Note that we have not conducted an independent evaluation of the amounts shown in Cols (C) and (G) of Table 2 and as such cannot render an opinion on such amounts.

In terms of expenses and as shown on Table 1, the Company has considered the suite of major expense items driving working capital in its study. These include:

- The Cost of Power associated with purchases from the Ontario Independent System Operator ("IESO"), Hydro One Networks, and other embedded generators
- OM&A expenses
- Interest expense
- The Debt Retirement Charge (or "DRC")
- Payments in Lieu of Taxes ("or PILs") and,
- The Harmonized Sales Tax (or "HST")

The expense lead time associated with the two major drivers of working capital requirement, i.e., cost of power and OM&A expenses, have been estimated to be on average, 33.8 days and 11.2 days respectively. These are averages for 2009 and 2010 respectively and are the result of giving full consideration, where applicable, to both the mid-point method and dollar-weighting. Other drivers of working capital that have been considered by the Company and quantified include interest on long term debt (45.6 days), the debt retirement charge (33.3 days), and PIL's (5.1 days). Again, these are averages for 2009 and 2010 respectively and consider, where applicable, the use of both the mid-point method and dollar-weighting. Finally, the Company estimates that the working capital requirement associated with the HST represents approximately 0.80% of the Company's OM&A expenses including the cost of power. This working capital requirement is driven by timing differences between collections from and remittances to Revenue Canada of the HST and is calculated on a statutory basis.

It should be noted that within OM&A expenses, HOL has considered the following major components in its analysis:

- Payroll and Benefits including the Canada Pension Plan, Employment Insurance, Payments on account of the Workers Safety Improvement Board (or "WSIB"), the Ontario Municipal Employment Retirement System (or "OMERS"), the Employer Health Tax (or "EHT") and various categories of health and welfare benefits provided by the Company to its employees.
- Payments made to Consulting and Contract Staff
- Payments on account of Property Taxes, and
- Miscellaneous OM&A.

Considered together and on a dollar-weighted basis, the expense weighted lead time for OM&A expenses is 11.2 days on average for 2009 and 2010.

Discussion

Any assessment of the working capital requirements of a regulated electric distributor such as HOL based on a lead-lag study would, at a minimum, require the following two criteria to be addressed:

- Completeness. The completeness of a study on working capital requirements depends on the breadth of payment and receipt items considered. The wider the breadth of items considered, the clearer the picture of the working capital requirements of a business such as HOL.

- Consistency, in terms of methodology with other such studies that have been accepted by the Board. As defined here, consistency would entail selecting between actual data or statutory approaches when quantifying revenue lag and expense lead times. The use of the mid-point methodology and the application of dollar-weighting where appropriate would also be factors to consider.

The Company's study has considered a broad spectrum of revenue and expense items including the cost of power. Major items relating to the day to day operations of the Company (OM&A) such as payroll and benefits, consulting and contract staff related expenses, WSIB payments, property taxes, and PIL's have been included in the analysis thereby enhancing its completeness. Additionally, the Company has taken into consideration interest expense payments, debt retirement charge payments, and HST pass-through's when calculating its working capital requirements. The expense categories are wide enough in terms of the breadth of the Company's operations to be a snap-shot of how the Company does business on a daily basis. Thus, it would be reasonable to conclude that the working capital study performed by HOL is **complete** in terms of items that have been considered including the two key ones, i.e., OM&A expenses and cost of power.

Is HOL's study **consistent** with other studies that have been accepted by the Board? By and large, yes. The Company has prudently used a combination of actual data and statutory approaches for the determination of revenue lags and/or expense lead times while at the same time giving due consideration, where appropriate, to the use of both the mid-point method and Dollar-Weighting in its calculations. Consider, for instance, the key features of how HOL calculated the revenue lag associated with providing bundled service to its residential and small business customers, i.e., the majority of its revenues:

- The Company has used a customer-weighting approach in its calculation of the service lag component. This is consistent with prior studies that have been either filed with and/or accepted by the OEB.[3]
- The Company's estimate of the Billing lag, while HOL specific, is based on methods and constraints similar to those which have been used by HONI, THESL, and Horizon in their distribution rate applications.
- In terms of calculating its collections lag however, the Company has conservatively elected to use a simple Days of Sales Outstanding ("DSO", or average accounts receivable turnover) method for calculating its collections lag time. Had HOL elected to perform a more rigorous sales-weighted or true DSO analysis, we believe that the result would have been a collections lag time higher than the 25.41 days used by the Company here. Note that the 25.41 days is an average of 2009 and 2010. In the alternative, had the Company elected to use a mid-point method as a proxy for either a sales weighted or true DSO analysis, the result would still have been higher, and more representative of actual

[3] See EB-2005-0378, EB-2007-0680, EB-2009-0096, and EB-2010-0131.

collections, compared with the simple DSO analysis it elected to use. In this respect, the Company's result of 14.2% of OM&A including cost of power is conservative.

- HOL's payment processing lag time of 1.14 days, while HOL specific, has been calculated in a manner generally consistent with that used by Horizon and THESL in their last distribution rate applications.
- HOL's revenue lag result considering all sources of revenues (75.3 days on average for 2009 and 2010) is the result of dollar-weighting as shown on Table 2.

Focusing on the calculation of expense lead days, HOL has aptly calculated the expense lead times associated with cost of power, payroll and benefits, consulting and contract staff, miscellaneous OM&A expenses, interest expense, PILs, and the Debt Reduction Charge giving due consideration to both the mid-point method and dollar-weighting where actual data has been used. The expense lead time associated with HST on the other hand, has been calculated using a statutory approach, i.e., payments or receipts are due on the last day of the month following the date on an invoice. Both these approaches are consistent with that used by Horizon, HONI, and THESL in their last distribution rate applications before the Board.

In conclusion, the methods used for calculating both revenue lags and expense leads in the HOL study are, for practical purposes, identical to and therefore, consistent with those used in the Horizon, HONI, and THESL studies filed with or accepted by the OEB. We conclude therefore that HOL's study is **consistent,** in terms of methodology, with current practice for electricity distributors in the province of Ontario.

For the various reasons discussed above, we conclude that HOL's result in terms of its request for working capital, i.e., 14.2% of OM&A expenses including the cost of power, is **reasonable**. It represents a working capital requirement as evidenced by the Company's 2009-10 operations and is based on a study that is comparable in terms of approach, though not necessarily its result which by definition is HOL specific, with those supporting other such requests that have been historically accepted by the OEB.

Jane, it has been my pleasure to support you on this important project. Please let us know if you require our assistance on similar endeavors in the future.

Sincerely,

Nagendra S. Krishna

Nagendra ("Subba") Subbakrishna
Associate Director, Energy

Table 2 - Revenue Lag from Residential and General Service Customers

Revenue Lag Component	Days	
	2009	2010
Service Lag	30.24	30.24
Billing Lag	18.11	18.24
Collections Lag	25.47	25.36
Payment Processing and Bank Float Lag	1.15	1.13
TOTAL	74.97	74.97

2.1.1 Service Lag

Service lag is the number of days between when service is provided to a customer and when the customer's meter is read. Residential and general service < 50kW customers' meters are read on a bi-monthly basis, and other classes of customers' meters are read monthly. Based on this information and using the number of customers in each class, a weighted average service lag of 30.24 is determined for 2009 and 2010. Table 3 and Table 4 show the details.

Table 3 - 2009 Service Lag – Residential and General Service Customers

Customer Type	Average # of Customers	Frequency of Meter Read	Mid Point of Service Period	Customer Weight	Service Lag
Residential	267,225	Bi-monthly	30.42	90.88%	27.65
General Service < 50 kW	23,312	Bi-monthly	30.42	7.93%	2.41
GS 50 – 1,499 kW	3,279	Monthly	15.21	1.12%	0.17
GS 1,500 – 4,999 kW	67	Monthly	15.21	0.02%	-
Large Users	11	Monthly	15.21	0.00%	-
Street Lighting	8	Monthly	15.21	0.00%	-
Unmetered Scattered Load	143	Monthly	15.21	0.05%	0.01
TOTAL	294,045			100.00%	30.24

Table 4 - 2010 Service Lag – Residential and General Service Customers

Customer Type	Average # of Customers	Frequency of Meter Read	Mid Point of Service Period	Customer Weight	Service Lag
Residential	271,603	Bi-monthly	30.42	90.98%	27.68
General Service < 50 kW	23,434	Bi-monthly	30.42	7.85%	2.39
GS 50 – 1,499 kW	3,279	Monthly	15.21	1.10%	0.16
GS 1,500 – 4,999 kW	66	Monthly	15.21	0.02%	-
Large Users	12	Monthly	15.21	0.00%	-
Street Lighting	8	Monthly	15.21	0.00%	-
Unmetered Scattered Load	129	Monthly	15.21	0.04%	0.01
TOTAL	298,531			100.00%	30.24

2.1.2 Billing Lag

Billing lag is the number of days between when a customer's meter is read and the date the customer is billed. This data is available from Hydro Ottawa's customer information system ("CIS") for each customer class. A query was generated from the CIS database to measure the average number of days between meter reads and billing date for all customers by class in 2009 and 2010.

With Hydro Ottawa's CIS, bills are produced once the spot market price is available (10 business days after the service period end date,) even for those that are on the fixed regulated price plan. The system needs to calculate the difference between what would have been billed at the spot market price and billed at the fixed rate for the purposes of filing claims with the Independent Electricity System Operation ("IESO") each month. The system also needs to calculate the difference between what would have been billed at the spot market price and what is billed based on a retail contract for the purposes of settlement. All of this must happen before the bill is finalized.

The weighted average billing lag for 2009 is 18.11 days, and for 2010 is 18.24 days. Table 5 and Table 6 show the details.

the power to help you succeed.

Report for

Ontario Energy Board

Third Generation Incentive Regulation Stretch Factor Updates for 2010 (EB-2009-0392)

February 17, 2010

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Table 5: Peer Group Divisions[18]

Peer Groups for Ontario LDCs

Peer Group Designation	Distributor	Customers[1]	% Undergrounding[1]	Canadian Shield	Customer Growth/Output Index[1]
Small Northern Low Undergrounding	Atikokan Hydro	1,676	0.5%	Yes	-1801
Small Northern Low Undergrounding	Chapleau Public Utilities	1,335	3.7%	Yes	-2023
Small Northern Low Undergrounding	Espanola Regional Hydro Distribution	3,349	8.0%	Yes	696
Small Northern Low Undergrounding	Fort Frances Power	4,001	9.5%	Yes	1142
Small Northern Low Undergrounding	Great Lakes Power	11,587	0.2%	Yes	273
Small Northern Low Undergrounding	Northern Ontario Wires	6,055	1.4%	Yes	-865
Small Northern Low Undergrounding	Parry Sound Power	3,358	8.6%	Yes	661
Small Northern Low Undergrounding	Renfrew Hydro	4,194	3.6%	No	633
Small Northern Low Undergrounding	Sioux Lookout Hydro	2,734	2.8%	Yes	38
Small Northern Medium Undergrounding	Hearst Power Distribution	2,763	16.2%	Yes	172
Small Northern Medium Undergrounding	Kenora Hydro Electric	5,583	10.2%	Yes	-227
Small Northern Medium Undergrounding	Lakeland Power Distribution	9,295	20.0%	Yes	1116
Small Northern Medium Undergrounding	Ottawa River Power	10,381	13.0%	Yes	1084
Mid-Size Northern	Greater Sudbury Hydro	46,215	20.1%	Yes	21
Mid-Size Northern	North Bay Hydro Distribution	23,669	15.7%	Yes	398
Mid-Size Northern	PUC Distribution	32,734	15.9%	Yes	345
Mid-Size Northern	Thunder Bay Hydro Electricity Distribution	49,361	19.8%	Yes	389
Large Northern	Hydro One Networks	1,187,253	3.5%	Yes	1045
Small Southern Low & Medium Undergrounding	Brant County Power	9,456	11.9%	No	2191
Small Southern Low & Medium Undergrounding	Clinton Power	1,639	19.0%	No	339
Small Southern Low & Medium Undergrounding	Dutton Hydro	600	14.3%	No	2816
Small Southern Low & Medium Undergrounding	Eastern Ontario Power	3,543	5.1%	No	266
Small Southern Low & Medium Undergrounding	Grand Valley Energy	681	11.1%	No	1165
Small Southern Low & Medium Undergrounding	Hydro 2000	1,177	14.3%	No	1274
Small Southern Low & Medium Undergrounding	Hydro Hawkesbury	5,375	13.8%	No	1713
Small Southern Low & Medium Undergrounding	Lakefront Utilities	9,215	16.7%	No	2164
Small Southern Low & Medium Undergrounding	Port Colborne	9,229	4.8%	No	417
Small Southern Low & Medium Undergrounding	Rideau St. Lawrence Distribution	5,859	10.2%	No	246
Small Southern Low & Medium Undergrounding	Wellington North Power	3,535	12.0%	No	1259
Small Southern Medium-High Undergrounding	Middlesex Power Distribution	7,026	23.6%	No	1842
Small Southern Medium-High Undergrounding	Midland Power Utility	6,773	31.3%	No	1865
Small Southern Medium-High Undergrounding	Newbury Power	199	25.0%	No	1194
Small Southern Medium-High Undergrounding	Tillsonburg Hydro	6,622	34.6%	No	1656
Small Southern Medium-High Undergrounding	West Coast Huron Energy	3,878	20.0%	No	1012
Small Southern Medium-High Undergrounding	West Perth Power	2,007	30.6%	No	1270
Small Southern Medium-High Undergrounding with Rapid Growth	Centre Wellington Hydro	6,309	47.3%	No	3340
Small Southern Medium-High Undergrounding with Rapid Growth	Cooperative Hydro Embrun	1,936	44.4%	No	6832
Small Southern Medium-High Undergrounding with Rapid Growth	Grimsby Power	9,937	25.2%	No	3570
Small Southern Medium-High Undergrounding with Rapid Growth	Niagara-on-the-Lake Hydro	7,798	26.7%	No	2665
Small Southern Medium-High Undergrounding with Rapid Growth	Orangeville Hydro	10,200	41.0%	No	3335
Mid-size Southern Low & Medium Undergrounding	Fort Erie	15,616	8.0%	No	597
Mid-size Southern Low & Medium Undergrounding	Haldimand County Hydro	20,815	4.8%	No	785
Mid-size Southern Low & Medium Undergrounding	Innisfil Hydro Distribution Systems	14,471	18.9%	No	2361
Mid-size Southern Low & Medium Undergrounding	Norfolk Power Distribution	18,806	12.2%	No	3042
Mid-size Southern Low & Medium Undergrounding	Orillia Power Distribution	12,797	19.4%	No	1286
Mid-size Southern Medium-High Undergrounding	Bluewater Power Distribution	36,218	23.2%	No	947
Mid-size Southern Medium-High Undergrounding	Chatham-Kent Hydro	32,094	28.4%	No	388
Mid-size Southern Medium-High Undergrounding	COLLUS Power	14,387	34.6%	No	2605
Mid-size Southern Medium-High Undergrounding	E.L.K. Energy	10,853	39.5%	No	2234
Mid-size Southern Medium-High Undergrounding	Erie Thames Powerlines	14,312	20.6%	No	1511
Mid-size Southern Medium-High Undergrounding	Essex Powerlines	27,929	51.4%	No	2593
Mid-size Southern Medium-High Undergrounding	Festival Hydro	19,394	32.8%	No	1602
Mid-size Southern Medium-High Undergrounding	Kingston Electricity Distribution	26,940	34.7%	No	172
Mid-size Southern Medium-High Undergrounding	Niagara Peninsula Energy	50,255	23.8%	No	3119
Mid-size Southern Medium-High Undergrounding	Peterborough Distribution	34,349	30.2%	No	1351
Mid-size Southern Medium-High Undergrounding	St. Thomas Energy	16,133	35.2%	No	2751
Mid-size Southern Medium-High Undergrounding	Wasaga Distribution	11,660	48.1%	No	6492
Mid-size Southern Medium-High Undergrounding	Welland Hydro-Electric System	21,706	25.5%	No	937
Mid-size Southern Medium-High Undergrounding	Westario Power	21,592	29.8%	No	1372
Mid-size Southern Medium-High Undergrounding	Woodstock Hydro Services	14,645	36.6%	No	1617
Large City Southern Medium-High Undergrounding	ENWIN Powerlines	84,644	36.2%	No	1262
Large City Southern Medium-High Undergrounding	Hydro Ottawa	291,639	49.0%	No	2735
Large City Southern Medium-High Undergrounding	Toronto Hydro-Electric System	684,145	57.0%	No	618
Large City Southern Medium-High Undergrounding	Veridian Connections	110,861	35.1%	No	2924
Large City Southern High Undergrounding	Enersource Hydro Mississauga	186,929	65.4%	No	2492
Large City Southern High Undergrounding	Horizon Utilities	233,947	53.9%	No	1322
Large City Southern High Undergrounding	Hydro One Brampton Networks	129,585	70.6%	No	5897
Large City Southern High Undergrounding	London Hydro	143,797	50.8%	No	2241
Large City Southern High Undergrounding	PowerStream	244,573	66.5%	No	4771
Mid-size GTA Medium-High & High Undergrounding	Barrie Hydro Distribution	69,628	55.0%	No	4925
Mid-size GTA Medium-High & High Undergrounding	Brantford Power	37,473	45.5%	No	2278
Mid-size GTA Medium-High & High Undergrounding	Burlington Hydro	62,737	39.0%	No	3110
Mid-size GTA Medium-High & High Undergrounding	Cambridge and North Dumfries Hydro	49,297	34.4%	No	2644
Mid-size GTA Medium-High & High Undergrounding	Guelph Hydro Electric Systems	48,914	59.1%	No	3423
Mid-size GTA Medium-High & High Undergrounding	Halton Hills Hydro	20,818	35.3%	No	2729
Mid-size GTA Medium-High & High Undergrounding	Kitchener-Wilmot Hydro	84,195	44.2%	No	2892
Mid-size GTA Medium-High & High Undergrounding	Milton Hydro Distribution	25,373	37.0%	No	7106
Mid-size GTA Medium-High & High Undergrounding	Newmarket Hydro & Tay Hydro	31,874	44.5%	No	2839
Mid-size GTA Medium-High & High Undergrounding	Oakville Hydro Electricity Distribution	62,038	61.3%	No	4356
Mid-size GTA Medium-High & High Undergrounding	Oshawa PUC Networks	51,813	48.2%	No	2244
Mid-size GTA Medium-High & High Undergrounding	Waterloo North Hydro	50,478	31.3%	No	2924
Mid-size GTA Medium-High & High Undergrounding	Whitby Hydro Electric	39,225	51.9%	No	5415

[1]Latest year of available data.

[18] Peer groups are identical to those proposed in the Original Report, except where amalgamations necessitated modifications.

using a statistical analysis software program called *MetrixND.* The following historical data was used as inputs into the models:

- system load data May 2002 to December 2010 – hourly energy data,
- system load data 1997 to May 2002 – monthly energy data,
- customer count, energy consumption and peak demand (monthly sales data, 2002 to December 2010),
- weather data from 1952 to 2010 – temperature and humidity, monthly Heating Degree Days ("HDD") and Cooling Degree Days (CDD") obtained from Environment Canada for the Ottawa Macdonald-Cartier International Airport, and
- economic variables for the Ottawa area: population, Gross Domestic Product ("GDP"), Real Personal Income ("RPI"), etc., received from the Conference Board of Canada, dated December 21, 2010.

Two main forecasts were developed for the purposes of the rate setting exercise; a system forecast of energy and demand, and a class sales forecast. As well, a forecast of peak demand was developed for system planning purposes based on more extreme weather conditions.

3.0 MODELLING RESULTS

3.1 System Energy Forecast

The system energy forecast (purchases) model was estimated using the available data from 1997 through 2010, thus including a period of strong growth from 1997-2002, a period of reduced growth 2002-2007, a period of recession 2008-2009, and the beginning of the recovery period, 2009-2010. The main variable driving the model is Gross Domestic Product for the Greater Ottawa area, which was obtained from the Conference Board of Canada, December 21, 2010 forecast. Heating Degree Days with bases of 8 and 18 degrees Celsius and Cooling Degree Days with an 18 degree Celsius base were found to best capture the relationship between weather and system wide energy consumption. HDD is a measurement designed to reflect the demand for energy needed to heat a home. It is calculated using the average

6.0 SALES FORECASTS

6.1 Class Billed Sales and Demand Forecast

The class sales forecast process consisted of three sequential steps. First, sales forecast models for each class were created that capture the relationship between class sales and a number of explanatory variables. Second, the billed-month forecast was converted to a calendar-month basis by simulating the models with calendar-month weather variables. In the final step, the calendar-month class sales forecasts were calibrated to the system energy forecast to produce the final class level sales forecast.

Class sales forecast models were created for the following customer groups:

- Residential,
- GS50 (General Service Less Than 50 kW),
- GS1000NI (Non-Interval 50 kW – 1000 kW),
- GS1000I (Interval 50 kW – 1000 kW),
- GS1500 (1000 kW – 1500 kW),
- GS5000 (1500 KW – 5000 kW),
- GSLRG (Over 5000 kW),
- Street Lighting, and
- Unmetered Scattered Loads ("USL").

Note that the GS 1000NI, GS1000I and GS1500 customer groups combine to be the General Service 50 to 1,499 kW Rate Class. Billing demand forecasts were estimated directly using the billed-month data and were not calibrated to a control total. Class demand forecast models were created for the following customer groups:

- GS1000NI (Non-Interval 50 kW – 1000 kW),
- GS1000I (Interval 50 kW – 1000 kW),
- GS1500 (1000 kW – 1500 kW),
- GS5000 (1500 KW – 5000 kW),

Table 8 – Actual/Forecast Sales (MWh) by Class

Year	Res	GS50	GS1000NI	GS1000I	GS1500	GS5000	GSLRG	StLgt	USL[2]	Total	% Growth
2005	2,358,152	784,296	1,857,173	805,206	372,746	821,857	626,330	37,438		7,663,197	
2006	2,226,416	747,557	1,754,320	840,405	369,187	821,669	654,955	36,133	12,722	7,463,363	-2.6%
2007	2,234,039	748,535	1,718,518	887,912	387,421	843,570	666,074	40,591	18,134	7,544,795	1.1%
2008	2,226,079	742,015	1,693,799	952,211	374,836	845,348	665,878	37,459	21,295	7,558,919	0.2%
2009	2,256,568	731,103	1,650,879	1,019,856	356,051	850,115	633,983	38,844	19,879	7,557,278[3]	0.0%
2010	2,272,251	726,404	1,609,927	1,065,718	341,642	829,446	685,667	43,535	17,309	7,591,898	0.5%
2011	2,268,990	766,682	1,656,238	1,025,863	347,511	831,101	663,932	40,798	17,392	7,618,507	0.35%
2012	2,254,962	760,702	1,644,428	1,031,869	343,940	827,861	665,596	40,737	17,184	7,587,280	(0.41%)

Table 9 – Weather Normal/Forecast Sales (MWh) by Class

Year	Res	GS50	GS1000NI	GS1000I	GS1500	GS5000	GSLRG	StLgt	USL[2]	Total	% Growth
2005	2,275,236	766,620	1,868,137	785,810	368,565	811,199	614,678	36,893		7,527,137	
2006	2,244,471	766,154	1,775,971	854,680	368,846	818,385	653,803	38,143		7,520,453	-0.1%
2007	2,255,875	741,852	1,708,864	900,830	391,218	848,434	674,915	39,662	21,429	7,583,079	0.8%
2008	2,239,394	755,114	1,720,686	969,161	381,025	859,462	668,185	37,820	21,677	7,652,523	0.9%
2009	2,261,789	740,166	1,676,495	1,006,025	352,131	841,800	641,326	38,360	19,761	7,577,853	-1.0%
2010	2,286,858	731,073	1,620,276	1,072569	343,838	834,778	690,075	43,815	17,420	7,640,700	0.83%
2011	2,268,990	766,682	1,656,238	1,025,863	347,511	831,101	663,932	40,798	17,392	7,618,507	(0.29%)
2012	2,254,962	760,702	1,644,428	1,031,869	343,940	827,861	665,596	40,737	17,184	7,587,280	(0.41%)

[2] Before 2006 USL was included in GS < 50 kW class and before 2007 Weather Normal information for UML was not provided.
[3] Does not equal Retail kWh reported in RRR as Dry core Transformer losses not included

Undertaking

<u>Undertaking LT2.6</u>

To provide a revised response to Staff No. 27 that separated the CDM adjustments from suite-metering adjustments.

Response

As discussed at the Technical Conference, VECC Technical Conference Question No. 20 prompted Hydro Ottawa Limited ("Hydro Ottawa") to review the kWh savings for 2012 as a result of the Ontario Energy Board's Conservation and Demand Management ("CDM") targets. As a result of the change in the meaning of 'cumulative', Hydro Ottawa has revised the adjustment to the 2012 load forecast related to CDM as shown below in the updated Tables 5 and 6 from Exhibit C1-1-1:

Table 5 – Estimated Achievement of CDM Targets

	Net Annual Peak Demand Savings (MW)		Net Cumulative Energy Savings (GWh)		
	Per Year	Cumulative	Per Year	Total Impact in Year	Cumulative
2011	13.72	13.72	41.403	41.403	41.403
2012	24.00	37.72	45.430	86.833	128.236
2013	24.86	62.58	46.430	133.263	261.499
2014	23.14	85.72	46.430	179.693	443.497

Table 6 – CDM Adjusted Load Forecast

	Forecasted System Peak (MW)				Forecasted System Energy (GWh)			
	Without CDM	With CDM	CDM Reduction	% Change	Without CDM	With CDM	CDM Reduction	% Change
2011	1,435	1,421	14	-1.0%	7,957	7,916	41	-0.5%
2012	1,448	1,410	38	-2.6%	8,030	7,943	87	-1.1%

As a result of the above change, Table 1 from Exhibit K3-1-5 (Board Staff #27) has been updated and as requested by VECC, the adjustments made for CDM and Suite Metering have been shown separately.

Table 1 from Exhibit K3-1-5 (Board Staff #27) Sales in MWh

Year	Res	GS50	GS1000NI	GS1000I	GS1500	GS5000	GSLRG	StLgt	USL	Dry Core Transformer Losses	Total	% Growth
2010	2,286,858	731,073	1,620,276	1,072,569	343,838	834,778	690,075	43,815	17,420	3,010	7,643,712	0.83%
2011 before adjustments	2,286,381	772,865	1,669,594	1,035,043	350,314	837,804	669,287	41,127	17,533	3,023	7,682,970	0.51%
2011 Suite Meter adjustment	900		-900								0	
2011 CDM adjustments	11,432	3,864	8,348	5,175	1,752	4,189	3,346	206	88	15	38,415	
2011 after adjustments	2,275,849	769,001	1,660,346	1,029,868	348,562	833,615	665,940	40,921	17,445	3,008	7,644,555	0.01%
2012 before adjustments	2,297,816	777,019	1,679,702	1,059,519	351,317	845,619	679,874	41,611	17,553	3,026	7,753,056	0.91%
2012 Suite Meter adjustment	5,400		-5,400								0	
2012 CDM adjustments	25,276	8,547	18,477	11,655	3,864	9,302	7,479	458	193	33	85,284	
2012 after adjustments	2,277,940	768,472	1,655,825	1,047,864	347,453	836,318	672,395	41,153	17,360	2,993	7,667,773	0.30%

Forecasted Sales by Rate Class with and without the Calibration Factor (MWh)

With Calibration Factor

2012	System Forecast	Loss Adjusted System Forecast	Loss Factor	Calibration Factor	Sum of Sales	Residential	GS < 50 kW	GS > 50 < 1500 kW	GS > 1500< 5000 kW	Large Use	Street Light	UMSL	Dry Core
1	765,007	738,638	1.0357	1.01	738,638	233,662	76,653	292,978	72,500	56,512	4,572	1,502	259
2	703,281	679,039	1.0357	0.97	679,039	213,926	70,915	269,028	67,875	51,511	4,097	1,440	248
3	690,220	666,429	1.0357	0.98	666,429	202,520	68,255	266,582	69,442	54,178	3,744	1,456	251
4	606,043	585,153	1.0357	0.94	585,153	168,537	59,020	235,162	65,377	52,103	3,309	1,403	242
5	604,466	583,630	1.0357	0.98	583,630	160,277	57,541	236,423	68,740	56,030	2,904	1,464	252
6	648,062	625,723	1.0357	0.99	625,723	181,461	60,847	247,511	72,063	59,443	2,679	1,467	253
7	696,881	672,860	1.0357	1.00	672,860	200,698	64,657	263,975	76,052	63,797	1,942	1,482	256
8	694,237	670,307	1.0357	1.00	670,307	199,000	64,412	263,380	75,991	63,671	2,105	1,490	257
9	614,497	593,316	1.0357	1.00	593,316	163,890	58,271	238,795	70,186	57,319	3,116	1,484	256
10	622,944	601,472	1.0357	0.97	601,472	169,686	59,901	242,885	68,214	55,178	3,910	1,448	250
11	648,904	626,537	1.0357	0.96	626,537	184,765	63,590	250,876	67,573	53,631	4,419	1,436	248
12	735,297	709,952	1.0357	1.00	709,952	219,392	72,959	282,942	71,607	56,502	4,812	1,483	256
Total	8,029,840	7,753,056			7,753,056	2,297,816	777,019	3,090,538	845,619	679,874	41,611	17,553	3,026

Without Calibration Factor

2012	System Forecast	Loss Adjusted System Forecast			Sum of Sales	Residential	GS < 50 kW	GS > 50 < 1500 kW	GS > 1500< 5000 kW	Large Use	Street Light	UMSL	Dry Core
1	765,007	738,638			731,325	231,349	75,894	290,077	71,782	55,952	4,527	1,487	256
2	703,281	679,039			700,040	220,542	73,108	277,348	69,974	53,105	4,223	1,484	256
3	690,220	666,429			680,030	206,653	69,648	272,022	70,859	55,284	3,821	1,486	256
4	606,043	585,153			622,503	179,295	62,787	250,173	69,550	55,428	3,521	1,492	257
5	604,466	583,630			595,541	163,548	58,715	241,248	70,143	57,173	2,963	1,494	258
6	648,062	625,723			632,044	183,294	61,461	250,011	72,791	60,043	2,706	1,481	255
7	696,881	672,860			672,860	200,698	64,657	263,975	76,052	63,797	1,942	1,482	256
8	694,237	670,307			670,307	199,000	64,412	263,380	75,991	63,671	2,105	1,490	257
9	614,497	593,316			593,316	163,890	58,271	238,795	70,186	57,319	3,116	1,484	256
10	622,944	601,472			620,074	174,934	61,754	250,397	70,324	56,884	4,031	1,493	257
11	648,904	626,537			652,643	192,464	66,239	261,329	70,389	55,866	4,603	1,495	258
12	735,297	709,952			709,952	219,392	72,959	282,942	71,607	56,502	4,812	1,483	256
Total	8,029,840	7,753,056			7,880,634	2,335,060	789,905	3,141,698	859,647	691,024	42,371	17,851	3,078

Undertaking

Undertaking LT1.14

To respond to VECC Technical Conference Question No. 27 and Board Staff Technical Conference Question No. 25.

Response

Please note Hydro Ottawa Limited ("Hydro Ottawa") does not propose these rates to be used and has only provided them as they were requested during the Technical conference. In Hydro Ottawa's opinion the Ontario Energy Board (the "Board") was clear in its decision related to PowerStream Inc. that only if the distributor had the data to perform a cost allocation approach should it be used. Hydro Ottawa does not have the proper data to create such rates and does not feel the rates prepared as part of this undertaking should be considered. Below Hydro Ottawa has included Board Staff's Technical Conference question 25. In Hydro Ottawa's opinion the excerpts provided illustrates Hydro Ottawa's opinion that class specific Smart Meter rates should not be used.

Furthermore Hydro Ottawa would urge that the Board, either through Hydro Ottawa's 2012 cost of service decision or through a generic hearing, provide clear guidance as to whether Local Distributor Companies ("LDC's") should be required to perform class specific Smart Meter rates when they do not have the required data. This guidance could create efficiencies in future cost of service rate proceedings, as all LDC's are still to file final Smart Meter costs.

Board Staff Technical Conference Question 25

> In its Decision (EB-2010-0209) with respect to PowerStream Inc.'s smart meter disposition application in 2010, the Board stated that "the Board is mindful that

full cost causality should be the guiding principle." However, the Board also noted that:

"The Board finds that a cost allocation approach based on class specific revenue requirement calculations offset by class specific smart meter funding to be inconsistent with previous Board decisions, and that there has been no clear requirement to track costs by class. The Board notes that historical funding collected from customer classes other than Residential and GS<50 kW is not material. The Board finds that a class specific calculation of the residual amounts for disposition of smart meter costs for each rate class is unwarranted, as there is insufficient benefit given the additional complexity."

The Board also noted that a more detailed approach could, depending upon a distributor's circumstances, result in rate volatility for some customers, and expressed its view that such volatility should be generally avoided.

Later in that same decision, with respect to PowerStream Inc.'s proposal for a SMIRR, the Board stated:

"The Board is mindful that a cost allocation approach for the prospective revenue requirement should ideally be based on a class specific revenue requirement calculation. However, the Board is concerned about distributors' ability to track all individual costs on a class specific basis at this point in the smart meter initiative, given that the instructions that have been issued by the Board in the recent past have not included this requirement. The requirements for the tracking of smart meter related costs have evolved to the point where no class by class tracking has been required since the initial implementation plans were filed. Furthermore, a cost allocation methodology in a cost of service rate application is based on reasonable cost drivers rather than tracked costs."

> In its decision, the Board approved a methodology whereby the smart meter disposition rider was calculated based on an allocation of the return on capital (interest expense and return on equity) and amortization expense proportional to the capital investments for each class.
>
> The Board will entertain proposals supported by analysis for SMDRs and SMIRRs based on principles of cost causality and where the distributor has the necessary historical and forecasted data.
>
> Hydro Ottawa has proposed that the Smart Meter Disposition Rider be collected uniformly from all metered customers, even though there are some customers (e.g. Large Users) who do not receive such meters or are not serviced by the associated infrastructure investments.

Hydro Ottawa tracked the cost of the meter and the installation separately. Additionally Residential costs were recorded separately from Commercial costs (Commercial meters include GS < 50 kW). Demand and collector meters however were not recorded separately. Demand meters are part of the Commercial grouping and collector meters are part of both the Residential and the Commercial grouping.

To determine the cost of the demand and collector meters, Hydro Ottawa used general assumptions such as the length of time a specific type of meter takes to be installed and the average purchasing price of those meters in a given year. Hydro Ottawa used a meter report to determine how many meters of each group were installed in a given year by meter type. Hydro Ottawa then recalculated the cost of the meter and installation by meter type for both demand and collector type meters by taking the number of meters of each type and multiplying it by the hourly rate, burden rates and average purchasing cost. Hydro Ottawa used this information to calculate the per meter costs by class. Please note this results in all non-standard install costs or savings flowing through the Residential and General Service <50KW class.

Please find below the per unit cost by class including meter and installation costs.

Customer Class	Per Unit Costs ($)
Residential	145.17
General Service <50KW	371.35
General Service 50-1500KW	794.91
General Service 1500-5000 KW	1,804.27
Large Users	2,022.77

Please find below the revenue requirement by class and the over and under collection by class.

Table 1

Customer Class	Meter Cost	Software and Hardware Costs	OM&A	Interest	Total Revenue Requirement
Residential	15,418,741	1,276,437	6,327,770	(98,613)	22,924,335
General Service <50KW	3,362,862	265,200	532,441	(17,821)	4,142,683
General Service 50-1500KW	1,053,783	603,996	74,631	(7,420)	1,724,990
General Service 1500-5000 KW	41,227	-	-	(177)	41,050
Large Users	7,703	-	-	(33)	7,670
Total	**19,884,316**	**2,145,633**	**6,934,842**	**(124,064)**	**28,840,728**

Table 2

Customer Class	Revenue Collected to December 2011	Total Revenue Requirement	Over/Under collection	2012 average customers	To clear balance after Dec 2011	Proposed rate Rider
Residential	25,558,516	22,924,335	(2,634,181)	280,901	(0.78)	0.16
General Service <50KW	2,348,096	4,142,683	1,794,587	23,636	6.33	0.16
General Service 50-1500KW	329,537	1,724,990	1,395,452	3,313	35.10	0.16
General Service 1500-5000 KW	7,300	41,050	33,751	67	41.98	0.16
Large Users	1,137	7,670	6,533	12	45.37	0.16
Total	**28,244,586**	**28,840,728**	**596,142**	**307,929**		

Hydro Ottawa Limited
EB-2011-0054
2011-09-27
Exhibit #: MT2.4

2010 Final CDM Results: Summary

LDC: Hydro Ottawa Limited

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	Hydro Ottawa Limited					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	10,274	1.64	2589	3.79	6112	136,626	20.22	31,117	46.01	72,821
Consumer	Every Kilowatt Counts Power Savings Event	Products purchased	34,277	0.10	1068	0.22	2308	613,248	1.70	19,100	4.00	41,300
Consumer	Great Refrigerator Roundup	Appliances	4,816	0.42	2797	0.81	5255	67,822	5.96	39,290	11.64	73,912
Consumer	*peaksaver*®	Devices installed	4,455	2.49	10	2.74	11	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	128	1.66	9369	3.17	18465	1,532	19.80	111,740	37.82	220,230
Business	High Performance New Construction*	Projects	20	0.88	2004	1.26	2863	288	12.91	29,433	18.44	42,048
Business	Hydro Ottawa *peaksaver*® Small Commercial Pilot	Devices installed	939	0.80	2500	0.88	2750	939	0.80	2,500	0.88	2,750
Business	Multifamily Energy Efficiency Rebates	Projects	78	0.36	4303	0.48	5841	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	2,314	2.02	6194	2.04	6209	48,274	42.20	129,200	42.60	129,500
Business, Industrial	Demand Response 3	Facilities	17	17.14	336	17.14	336	246	251.70	4,932	251.70	4,932
Business, Industrial	Loblaw & York Region Demand Response*	Facilities	0	1.99	0	1.99	0	2	29.21	0	29.21	0
Industrial	Demand Response 2	Facilities	0	8.10	9472	8.10	9472	3	119.00	139,100	119.00	139,100
Total				37.6	40,642	42.6	59,622		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.
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	2) Program results are based on contracted nameplate capacity at the end of the calendar year and not actual summer coincident peak demand reduction.

* *Initiative is not evaluated*

Ontario

DEMAND SIDE MANAGEMENT GUIDELINES FOR NATURAL GAS UTILITIES

EB-2008-0346

Date: June 30, 2011

The potential for deviations from the forecasted impact of planned DSM activities and the actual impact of DSM activities undertaken by the natural gas utility introduces a risk and a disincentive for the natural gas utility to deliver those DSM programs. The LRAM is designed to remove this disincentive by truing up the actual impact of DSM activities undertaken by the natural gas utility from the forecasted impact.[30] Accordingly, the LRAM amount is a retrospective adjustment and may be an amount refundable to or receivable from the utility's customers, depending respectively on whether the actual natural gas savings resulting from the natural gas utility's DSM activities are less than or greater than what was included in the forecast for rate-setting purposes. A natural gas utility may only claim an LRAM amount in relation to DSM activities undertaken within its franchise area by itself and/or delivered for the natural gas utility by a third party under contract.

The LRAM amount is determined by calculating the difference between actual and forecast natural gas savings by customer class and monetizing those natural gas savings using the natural gas utility's Board-approved variable distribution charge appropriate to the rate class. As described in section 6 and 7, the input assumptions, savings estimates, and adjustment factors used in the calculation of the LRAM amount should be based on the best available information resulting from the evaluation and audit process of the same program year. For example, the 2012 LRAM amount will be based on the best available information resulting from the evaluation and audit process of the 2012 program year.

The natural gas utilities should calculate the first year impact of DSM programs on a monthly basis, based on the volumetric impact of the measures implemented in that month, multiplied by the distribution rate for each of the rate classes in which the volumetric variance occurs in. This approach will help ensure that LRAM amounts closely reflect the actual timing of the implementation of the DSM measures.

It is expected that new load forecasts will incorporate the impact of natural gas DSM activities already undertaken. Accordingly, LRAM amounts are only accruable until distribution rates based on a new load forecast are set by the Board.

The recording of LRAM amounts, and the disposition of the balance in the LRAM variance account, is described in sections 13.3 and 14 respectively.

13. ACCOUNTING TREATMENT

The DSM plan components (e.g., budget, LRAM, incentive structure, DSMVA) will be established at the outset of a multi-year DSM plan with the intention of applying throughout the currency of the multi-year DSM plan. However, the DSM plan components will all be developed and measured on an annual basis within the multi-

[30] The LRAM serves to remove a disincentive for the gas utilities to undertake DSM programs. In contrast, the incentive payments as outlined in section 11. is meant to encourage the gas utilities to aggressively pursue DSM savings and recognize exemplary performance.

Undertaking

Undertaking LT2.13

To respond to VECC Technical Conference Question No. 33.

Response

a) Please see the updated Table 1 below.

b) Based on the rates that were in effect for 2008-2010 and the adjustment for Conservation and Demand Management ("CDM") included in the 2008 approved Load Forecast, Table 2 provides the lost revenue for 2008-2010 associated with the 2008 approved CDM. Note the rates used for each year are a blended rate of 4 months of the previous year plus 8 months of the current year.

c) Based on the rates that were in effect for 2008-2010 and the actual savings associated with the 2008 CDM Programs, Table 2 provides the lost revenue for 2008-2010 due to the CDM programs. Note that an average rate was used for the Large Commercial kW savings as it was not possible to divide the savings among the individual classes.

Table 1

Class	Load Forecast Adjustment for CDM		Reported 2008 CDM Savings 3rd tranche		Reported 2008 CDM Savings OPA Programs	
	MWh	kW	MWh	kW	MWh	MW
Residential	21,334	N/A	0	0	11,335	1.7
General Service < 50 kW	3,071	N/A	177	0	88	4.2
General Service 50-1,500 kW[1]	12,368	5,409	11,933	1,868	2,510	36.6
General Service 1,500-5,000 kW	3,319	1,289				
Large Use	2,575	856				
Street lighting	0	79				
Total	42,667	7,633	12,170	1,868	13,933	42.5

[1] For Reported 2008 CDM Savings all Large Commercial savings are shown under GS > 50 < 1,500 kW.

Table 2

Variable Rates	2007	2008	2009	2010
Residential	$ 0.0183	$ 0.0205	$ 0.0207	$ 0.0207
GS < 50 kW	$ 0.0180	$ 0.0183	$ 0.0185	$ 0.0185
GS 50-1500 kW	$ 2.5463	$ 2.9918	$ 3.0271	$ 3.0325
GS 1500-5000 kW	$ 2.3357	$ 2.8573	$ 2.8910	$ 2.8962
Large Use	$ 2.5918	$ 2.7352	$ 2.7675	$ 2.7725
Street lighting	$ 2.4671	$ 3.4037	$ 3.4439	$ 3.4501

Based on 2008 Load Forecast Adjustment for CDM					Lost Revenue			
	MWh/kW	2008	2009	2010	2008	2009	2010	Total
Residential	21,334	$ 0.0198	$ 0.0206	$ 0.0207	$ 421,702	$ 440,192	$ 441,614	$ 1,303,507
GS < 50 kW	3,071	$ 0.0182	$ 0.0184	$ 0.0185	$ 55,892	$ 56,609	$ 56,814	$ 169,314
GS 50-1500 kW	5,409	$ 2.8433	$ 3.0153	$ 3.0307	$ 15,379	$ 16,310	$ 16,393	$ 48,082
GS 1500-5000 kW	1,289	$ 2.6834	$ 2.8798	$ 2.8945	$ 3,459	$ 3,712	$ 3,731	$ 10,902
Large Use	856	$ 2.6874	$ 2.7567	$ 2.7708	$ 2,300	$ 2,360	$ 2,372	$ 7,032
Street lighting	79	$ 3.0915	$ 3.4305	$ 3.4480	$ 244	$ 271	$ 272	$ 788
								$ 1,539,626

Based on Actual CDM Savings (2008 OPA and 3rd Tranche Programs)					Lost Revenue			
	MWh/kW	2008	2009	2010	2008	2009	2010	Total
Residential	11,335	$ 0.0198	$ 0.0206	$ 0.0207	$ 224,055	$ 233,879	$ 234,635	$ 692,569
GS < 50 kW	265	$ 0.0182	$ 0.0184	$ 0.0185	$ 4,823	$ 4,885	$ 4,903	$ 14,610
Average	38,463	$ 2.8264	$ 3.0206	$ 3.0360	$ 108,712	$ 116,181	$ 116,774	$ 341,667
								$ 1,048,846

Board's Tech Conf. 19(B)

GRID PROMISSORY NOTE

Effective the 1st day of January 2009.

As consideration for the transfer of funds by Hydro Ottawa Holding Inc. to Hydro Ottawa Limited, **Hydro Ottawa Limited,** (the "Borrower"), a corporation incorporated pursuant to the laws of the Province of Ontario, hereby unconditionally promises to pay to or to the order of **Hydro Ottawa Holding Inc.** (the "Lender") at Ottawa, Canada the principal amount advanced under this grid promissory note (the "Principal") together with interest at a rate specified below ("Interest") on the amount of Principal from time to time outstanding in lawful money of Canada upon the terms and subject to the conditions set forth below.

This Note is a negotiable instrument.

The following are the terms and conditions of the Note:

1. PRINCIPAL

(1) The total amount authorized will not exceed $75,000,000.00 CDN.

(2) Advances of Principal may be made in tranches to meet business requirements.

(3) The liability of the Borrower and of any guarantor of the Borrower ("Guarantor") or endorser in respect of Principal shall not exceed the outstanding amount of Principal.

(4) Advances shall be deemed conclusively to have been made to and for the benefit of the Borrower when,

(a) deposited or credited to the account of the Borrower by the Lender; or

(b) made in accordance with the instructions of the Borrower.

(5) All advances of Principal under this Note shall be evidenced by endorsement upon the grid attached to this Note as Schedule A (the "Grid").

(6) The Lender's Chief Financial Officer, President and Chief Executive Officer and Treasurer are authorized to endorse the Grid, including any continuation Grid that may be attached to this Note, the date and amount of each advance and together with the unpaid balance of the Principal and each endorsement shall be prima facie evidence of the amounts so advanced and the balance of principal outstanding under this Note.

2. **INTEREST RATE**

(1) Interest shall be payable upon the amounts advanced under this Note at a fixed rate of interest payable monthly in arrears on a mutually agreed date. The rate established for long term debt will be based on either of two methods:

a) If available, the actual cost of external long term debt, including issuance costs, issued to a 3rd party of which the proceeds, in part or total, flow through to Hydro Ottawa Limited or;
b) An estimated "deemed interest rate" which will be based on the underlying methodology outlined in the Ontario Energy Board's "Report of the Board" on the Cost of Capital for Ontario's Regulated Utilities EB-2009-0084 dated December 11, 2009. The rate will be determined from available information at the time of the advancement using indicative rates as provided to Hydro Ottawa Limited. The rate will also include estimated issuance costs that would be associated with an issuance. The rate that is in effect when the advance was made will be used for the duration of the advance as per the Term and Payment section. .
c) All changes to interest rates under this Note shall be evidenced by endorsement upon the Grid attached as Schedule A.

3. **ADMINISTRATIVE FEE**

An administrative charge will be added to the rate of interest charged on Long Term Debt advances at the rate of 0.10% per annum.

4. **TERM AND REPAYMENT**

(1) The Principal and any accrued and outstanding Interest payable under this Note shall be payable in full on February 9, 2015 unless otherwise agreed by Hydro **Ottawa Holding Inc.** and **Hydro Ottawa Limited.**

(2) **Hydro Ottawa Limited** may, at any time, repay the full Principal amount outstanding from time to time on this Note. In addition to any other amount then payable by the Borrower pursuant to the terms hereof (including, without limitation, accrued interest) in respect to the repayment, the Borrower shall pay to the Lender an amount equal to three months simple interest on the full Principal amount being repaid.

(3) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal and Interest payable within 30 days following a change of control of **Hydro Ottawa Limited.** For the purpose of this sub-section control means with respect to **Hydro Ottawa Limited** at any time (i) holding, as owner or other beneficiary – other than solely as beneficiary of an unrealized security interest – directly or indirectly, securities or ownership interests of **Hydro Ottawa Limited**

carrying votes or ownership interests sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management or **Hydro Ottawa Limited**, or (ii) the exercise of de facto control of **Hydro Ottawa Limited**, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract, trust or otherwise.

5. SUBORDINATION

The obligation of **Hydro Ottawa Limited** to pay the Principal Amount or the amount remaining unpaid from time to time on this Grid Promissory Note are subordinated and postponed to the obligations of **Hydro Ottawa Limited** to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of **Hydro Ottawa Limited.**

a. WAIVER OF NOTICE IN EVENT OF DEFAULT

Hydro Ottawa Limited hereby waives presentment, protest and notice of any kind in the enforcement of this Grid Promissory Note. **Hydro Ottawa Limited** further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal Amount, or the amount remaining unpaid from time to time on this Grid Promissory Note, is not made when due.

b. RIGHTS AND REMEDIES IN EVENT OF DEFAULT

The rights and remedies of **Hydro Ottawa Holding Inc.** under this Grid Promissory Note which it may have at law or in equity against **Hydro Ottawa Limited** shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by **Hydro Ottawa Holding Inc.**, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of **Hydro Ottawa Limited** under this Grid Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by **Hydro Ottawa Holding Inc.** which may be brought to recover any amounts due and payable under this Grid Promissory Note. No delay or failure by **Hydro Ottawa Holding Inc.** in the enforcement of any covenant, promise or agreement of **Hydro Ottawa Limited** hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of **Hydro Ottawa Holding Inc.** shall only occur and be valid when set forth in writing by **Hydro Ottawa Holding Inc.** No waiver of any event of default shall discharge or release any person at any time liable for the payment of this Grid Promissory Note from such liability. No single or partial exercise of any of **Hydro Ottawa Holding Inc.**'s powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

c. **ASSIGNMENT**

This Grid Promissory Note may not be assigned **by Hydro Ottawa Holding Inc.** or **Hydro Ottawa Limited.**

d. **GOVERNING LAW**

This Grid Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF Hydro Ottawa Limited has duly executed this Grid Promissory Note on the date first appearing above.

HYDRO OTTAWA LIMITED

Per: ____________________
Name: Rosemarie T. Leclair
Title: President and Chief Executive Officer

Per: ____________________
Name: Alan Hoverd
Title: Chief Financial Officer

Schedule A

Advances and Payment of Principal

Date	Amount of Advance	Amount of Principal Payment	Unpaid Balance	Interest Rate	Recorded By
Dec 21, 2009	$15,000,000		$15,000,000	5.75%	[illegible]
April 30, 2010	$15,000,000		$30,000,000	5.87%	By [illegible]
July 5, 2011	$15,000,000		$45,000,000	5.45%	By [illegible]

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Telephone: 416- 481-1967
Facsimile: 416- 440-7656
Toll free: 1-888-632-6273

Commission de l'énergie de l'Ontario
C.P. 2319
27e étage
2300, rue Yonge
Toronto ON M4P 1E4
Téléphone: 416- 481-1967
Télécopieur: 416- 440-7656
Numéro sans frais: 1-888-632-6273

Ontario

BY E-MAIL AND WEB POSTING

March 3, 2011

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2011 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2011 Cost of Service Applications for Rates Effective May 1, 2011

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2011 rate year cost of service applications for rates effective May 1, 2011. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters.

Every year, the Board updates the Cost of Capital parameters for use in setting rates for natural gas and electricity utilities for the coming rate year. The Board has normally updated the parameters once each year for rates effective May 1, 2011. In light of certain applications requesting January 1, 2011 effective dates for rate changes, the Board advanced its determination of the values for the Cost of Capital parameters based on the data available three months in advance of the January 1, 2011 date. On November 15, 2010, the Board issued a letter announcing updated Cost of Capital parameters for rates effective January 1, 2011. Also in that letter the Board stated that cost of service applications with rates effective May 1, 2011 would have updated Cost of Capital parameters based on data for January 2011.

The purpose of this letter is to announce updated Cost of Capital parameters for rates effective May 1, 2011. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Report"), issued December 11, 2009.

For rates with effective dates in 2011, the Board has updated the Deemed ST Debt rate parameters based on: (i) the September 2010 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low commercial customers for the short-term debt rate; and (ii) data for three months prior to the effective dates from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP, per the methodologies documented in the Report.

Cost of Capital parameters for rates effective May 1, 2011

Based on the methodologies set out in the Report and January 2011 data from the Bank of Canada, *Consensus Forecasts* and Bloomberg LLP, the Board has determined that the updated Cost of Capital parameters for 2011 cost of service rate applications for rates effective May 1, 2011 are:

Cost of Capital Parameter	Value for 2011 Cost of Service Applications for May 1, 2011 rate changes
ROE	9.58%
Deemed LT Debt rate	5.32%
Deemed ST Debt rate	2.46%

The Board considers these Cost of Capital parameter values and the relationships between them reasonable and representative of market conditions at this time. Detailed calculations of the Cost of Capital parameters are attached.

All queries on the Cost of Capital parameters should be directed to the Board's Market Operations hotline, at 416 440 7604 or market.operations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

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

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

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

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

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

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

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

Attachment AG

GRID PROMISSORY NOTE

Effective the 1st day of January 2009.

As consideration for the transfer of funds by Hydro Ottawa Holding Inc. to Hydro Ottawa Limited, **Hydro Ottawa Limited,** (the "Borrower"), a corporation incorporated pursuant to the laws of the Province of Ontario, hereby unconditionally promises to pay to or to the order of **Hydro Ottawa Holding Inc**. (the "Lender") at Ottawa, Canada the principal amount advanced under this grid promissory note (the "Principal") together with interest at a rate specified below ("Interest") on the amount of Principal from time to time outstanding in lawful money of Canada upon the terms and subject to the conditions set forth below.

This Note is a negotiable instrument.

The following are the terms and conditions of the Note:

1. PRINCIPAL

(1) The total amount authorized will not exceed $75,000,000.00 CDN.

(2) Advances of Principal may be made in tranches to meet business requirements.

(3) The liability of the Borrower and of any guarantor of the Borrower ("Guarantor") or endorser in respect of Principal shall not exceed the outstanding amount of Principal.

(4) Advances shall be deemed conclusively to have been made to and for the benefit of the Borrower when,

(a) deposited or credited to the account of the Borrower by the Lender; or

(b) made in accordance with the instructions of the Borrower.

(5) All advances of Principal under this Note shall be evidenced by endorsement upon the grid attached to this Note as Schedule A (the "Grid").

(6) The Lender's Chief Financial Officer, President and Chief Executive Officer and Treasurer are authorized to endorse the Grid, including any continuation Grid that may be attached to this Note, the date and amount of each advance and together with the unpaid balance of the Principal and each endorsement shall be prima facie evidence of the amounts so advanced and the balance of principal outstanding under this Note.

2. INTEREST RATE

(1) Interest shall be payable upon the amounts advanced under this Note at a fixed rate of interest payable monthly in arrears on a mutually agreed date. The rate established for long term debt will be based on either of two methods:

a) If available, the actual cost of external long term debt, including issuance costs, issued to a 3rd party of which the proceeds, in part or total, flow through to Hydro Ottawa Limited or;
b) An estimated "deemed interest rate" which will be based on the underlying methodology outlined in the Ontario Energy Board's "Report of the Board" on the Cost of Capital for Ontario's Regulated Utilities EB-2009-0084 dated December 11, 2009. The rate will be determined from available information at the time of the advancement using indicative rates as provided to Hydro Ottawa Limited. The rate will also include estimated issuance costs that would be associated with an issuance. The rate that is in effect when the advance was made will be used for the duration of the advance as per the Term and Payment section..
c) All changes to interest rates under this Note shall be evidenced by endorsement upon the Grid attached as Schedule A.

3. ADMINISTRATIVE FEE

An administrative charge will be added to the rate of interest charged on Long Term Debt advances at the rate of 0.10% per annum.

4. TERM AND REPAYMENT

(1) The Principal and any accrued and outstanding Interest payable under this Note shall be payable in full on February 9, 2015 unless otherwise agreed by Hydro **Ottawa Holding Inc.** and **Hydro Ottawa Limited.**

(2) **Hydro Ottawa Limited** may, at any time, repay the full Principal amount outstanding from time to time on this Note. In addition to any other amount then payable by the Borrower pursuant to the terms hereof (including, without limitation, accrued interest) in respect to the repayment, the Borrower shall pay to the Lender an amount equal to three months simple interest on the full Principal amount being repaid.

(3) **Hydro Ottawa Holding Inc.** may require that **Hydro Ottawa Limited** repay the Principal and Interest payable within 30 days following a change of control of **Hydro Ottawa Limited.** For the purpose of this sub-section control means with respect to **Hydro Ottawa Limited** at any time (i) holding, as owner or other beneficiary – other than solely as beneficiary of an unrealized security interest – directly or indirectly, securities or ownership interests of **Hydro Ottawa Limited**

carrying votes or ownership interests sufficient to elect or appoint the majority of individuals who are responsible for the supervision or management or **Hydro Ottawa Limited**, or (ii) the exercise of de facto control of **Hydro Ottawa Limited**, whether direct or indirect and whether through the ownership of securities or ownership interests, by contract, trust or otherwise.

5. SUBORDINATION

The obligation of **Hydro Ottawa Limited** to pay the Principal Amount or the amount remaining unpaid from time to time on this Grid Promissory Note are subordinated and postponed to the obligations of **Hydro Ottawa Limited** to a third party for the payment in full of any secured indebtedness and all security interests granted to secure such obligations of **Hydro Ottawa Limited.**

a. WAIVER OF NOTICE IN EVENT OF DEFAULT

Hydro Ottawa Limited hereby waives presentment, protest and notice of any kind in the enforcement of this Grid Promissory Note. **Hydro Ottawa Limited** further agrees to pay all costs of collection, including legal fees on a solicitor and client basis, in case the Principal Amount, or the amount remaining unpaid from time to time on this Grid Promissory Note, is not made when due.

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The rights and remedies of **Hydro Ottawa Holding Inc.** under this Grid Promissory Note which it may have at law or in equity against **Hydro Ottawa Limited** shall be distinct, separate and cumulative, and shall not be deemed inconsistent with one another, and none of the said rights, whether or not exercised by **Hydro Ottawa Holding Inc.**, shall be deemed to be to the exclusion of any other, and any one or more of said rights and remedies may be exercised at the same time. The obligations of **Hydro Ottawa Limited** under this Grid Promissory Note shall continue until the entire debt evidenced hereby is paid, notwithstanding any court action or actions taken by **Hydro Ottawa Holding Inc.** which may be brought to recover any amounts due and payable under this Grid Promissory Note. No delay or failure by **Hydro Ottawa Holding Inc.** in the enforcement of any covenant, promise or agreement of **Hydro Ottawa Limited** hereunder shall constitute or be deemed to constitute a waiver of such right. Any waivers of **Hydro Ottawa Holding Inc.** shall only occur and be valid when set forth in writing by **Hydro Ottawa Holding Inc.** No waiver of any event of default shall discharge or release any person at any time liable for the payment of this Grid Promissory Note from such liability. No single or partial exercise of any of **Hydro Ottawa Holding Inc.**'s powers hereunder shall preclude other and further exercise thereof or the exercise of any other power.

c. **ASSIGNMENT**

This Grid Promissory Note may not be assigned **by Hydro Ottawa Holding Inc**. or **Hydro Ottawa Limited.**

d. **GOVERNING LAW**

This Grid Promissory Note shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein.

IN WITNESS WHEREOF Hydro Ottawa Limited has duly executed this Grid Promissory Note on the date first appearing above.

HYDRO OTTAWA LIMITED

Per: ____________________
Name: Rosemarie T. Leclair
Title: President and Chief Executive Officer

Per: ____________________
Name: Alan Hoverd
Title: Chief Financial Officer

Schedule A

Advances and Payment of Principal

Date	Amount of Advance	Amount of Principal Payment	Unpaid Balance	Interest Rate	Recorded By
Dec 21, 2009	$15,000,000		$15,000,000	5.75%	
April 30, 2010	$15,000,000		$30,000,000	5.87%	By

2.2 Long Term Debt

Hydro Ottawa currently has $312.185M of long term debt in the form of promissory notes issued to the Holding Company at a weighted cost of 5.321% compared to the 5.258% rate approved in the 2008 Electricity Distribution Rate Application. As noted in section 1.0, a $45M increase in long term debt has been forecast for the 2011 bridge year and a $15M increase in long term debt has been forecast for the 2012 test year bringing the weighted cost of long term debt to 5.39%. Long term interest rates are expected to rise from their current levels during the bridge and test years. A summary of the notes and the weighted average cost calculation is shown in Table 1.

Table 1 – Weighted Average Cost of Long Term Debt

Description	Date of Issuance	Principal ($000's)	Interest Rate (%)	Weighted Debt Rate Cost
Promissory Note to Hydro Ottawa Holding Inc.	July 1, 2005	$ 200,000	5.140%	2.7621%
Promissory Note to Hydro Ottawa Holding Inc.	July 1, 2005	32,185	5.900%	0.5102%
Promissory Note to Hydro Ottawa Holding Inc.	December 20, 2006	50,000	5.318%	0.7144%
Promissory Note to Hydro Ottawa Holding Inc.	December 21, 2009	15,000	5.85%	0.2357%
Promissory Note to Hydro Ottawa Holding Inc.	April 1, 2010	15,000	5.97%	0.2406%
Promissory Note to Hydro Ottawa Holding Inc.	July 5, 2011	15,000	5.65%	0.2277%
Promissory Note to Hydro Ottawa Holding Inc.	September 1, 2011	15,000	5.75%	0.2317%
Promissory Note to Hydro Ottawa Holding Inc.	December 1, 2011	15,000	5.75%	0.2317%
Promissory Note to Hydro Ottawa Holding Inc.	July 1, 2012	15,000	5.75%	0.2317%
		$ 372,185		5.39%

2.2 Long Term Debt

Hydro Ottawa currently has $312.185M of long term debt in the form of promissory notes issued to the Holding Company at a weighted cost of 5.321% compared to the 5.258% rate approved in the 2008 Electricity Distribution Rate Application. As noted in section 1.0, a $45M increase in long term debt has been forecast for the 2011 bridge year and a $15M increase in long term debt has been forecast for the 2012 test year bringing the weighted cost of long term debt to 5.39%. Long term interest rates are expected to rise from their current levels during the bridge and test years. A summary of the notes and the weighted average cost calculation is shown in Table 1.

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Promissory Note to Hydro Ottawa Holding Inc.	July 1, 2012	15,000	5.75%	0.2317%
		$ 372,185		5.39%

2011 and 2012 issuances as the 100bps increase into 2012 was viewed to be aggressive considering the weakness in the world economy.

b) The Board issues updated long term rates twice a year to coincide with rate decisions beginning in January and May. The 5.32% was calculated using January 2011 information and was published in March of 2011. As noted in part a) above, this rate was used as the base at the time of the forecast and then adjusted to reflect future forecast rates at the scheduled time of the debt issuances in 2011 and 2012. It is Hydro Ottawa practice to use rates reflective of market conditions at the time of issuance to best reflect what an actual "market rate" would be.

c) The first 2011 long term tranche was issued on July 5th, 2011.

d) The following reflects an update to Table 1 for the July 5th debt issuance:

Table 1 – Weighted Average Cost of Long Term Debt

Description	Date of Issuance	Principal ($000's)	Interest Rate (%)	Weighted Debt Rate Cost
Promissory Note to Hydro Ottawa Holding Inc.	July 1, 2005	$ 200,000	5.140%	2.7621%
Promissory Note to Hydro Ottawa Holding Inc.	July 1, 2005	32,185	5.900%	0.5102%
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Promissory Note to Hydro Ottawa Holding Inc.	September 1, 2011	15,000	5.75%	0.2317%
Promissory Note to Hydro Ottawa Holding Inc.	December 1, 2011	15,000	5.75%	0.2317%

internal debt isn't fully synchronized, obviously, and a good example of that is our external 2005-2000 (sic) debt issuances. They weren't matched up with the timing of our rate applications, et cetera, so there was costs incurred there. So these should -- over time, obviously -- balance out as we do debt issuances.

We don't do them annually; we are not that size that we need to do that. As noted before, we've been using internal cash that we received on the sale of our telecom business for the last two, three years.

We do anticipate in 2012 that we would likely be doing an external debt issuance, and as well, in 2015 when our 2005 bonds renew, we will be doing, definitely, another bond issuance.

MR. RITCHIE: But in terms of the current 2012 rate year, subject to, I guess, whatever updates, and you did mention earlier that the September 1, 2011 note was actually -- has not been issued and is up for review, but in terms of the table 1 or what's in your Exhibit E1, that is your evidence as to what, in fact, will be the debt costs that Hydro Ottawa will have and should be used for setting its rates for 2012?

MR. GRUE: I believe that's correct. As I say, we are trying to emulate what an actual debt issuance will be, which we anticipate we will have at least two in the coming three, four years.

MR. RITCHIE: The second part of our question was that about the July 5th, 2011 and September 1, 2011 promissory notes. I believe there, in fact, may have been an IR that contained the July 5th, and you have just said that the September 1 is subject to review at the end of this quarter?

MR. GRUE: That's correct. We have issued the July 5th one. I believe we brought a copy of that, if you would like a copy of that. And September's has still not been issued, as per Energy Probe No. 34(a).

MR. RITCHIE: Again, I guess to the extent -- I guess I am subject to check whether the July 5th note has actually been filed on the record. I...

MR. GRUE: I don't think it has been filed. I believe we brought a copy of that for hand-out.

MR. RITCHIE: Okay. Yes, because it is an affiliated debt note, so...

MS. HELT: We will mark the July 5th, 2011 note as Exhibit MT1.11.

EXHIBIT NO. MT1.11: JULY 5, 2011 PROMISSORY NOTE.

MR. RITCHIE: I guess with respect to the next question, I don't intend to read it fully into the record.

I think that we have had a fair bit of discussion about sort of the issuance costs and which ones they apply to and, I guess at this point in time, why Hydro Ottawa is sort of proposing what it has. And it hasn't included issuance costs in the first two notes in 2009 and 2010, but it has included the 10 basis points.

I guess I might have one question, just -- and it is actually going back to this, to the grid promissory note

Rates Scenario

ECONOMIC RESEARCH

BMO Capital Markets

Fixed Income and Foreign Exchange Strategy

January 6, 2011

Forecast Summary (averages)

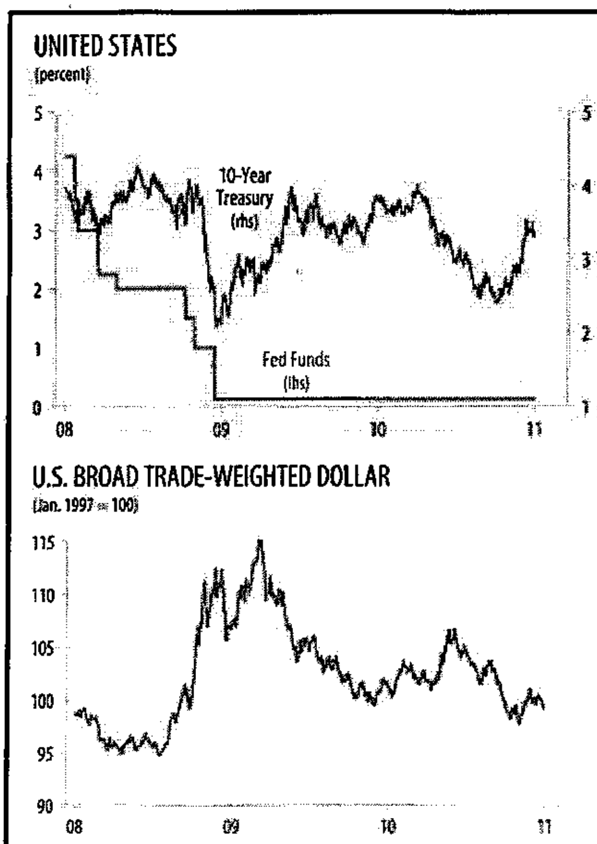
Michael Gregory, CFA
Senior Economist

Benjamin Reitzes
Economist

	Actual	2011			2011			2012			
	Dec	Jan	Feb	Mar	Q2	Q3	Q4	Q1	Q2	Q3	Q4
BoC overnight	1.00	1.00	1.00	1.00	1.15	1.50	1.85	2.35	2.85	3.35	3.75
10-yr Canadas	3.20	3.25	3.25	3.20	3.25	3.45	3.65	3.80	3.95	4.10	4.30
Fed funds	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.58	1.10	1.50	2.00
10-yr Treasuries	3.29	3.50	3.40	3.30	3.30	3.60	3.85	4.10	4.35	4.55	4.80
C$ per US$	1.008	1.005	1.005	1.000	1.000	0.991	0.979	0.979	0.985	0.992	0.998
US$/€	1.32	1.33	1.31	1.30	1.27	1.28	1.33	1.33	1.31	1.28	1.26
US$/£	1.56	1.55	1.54	1.53	1.51	1.53	1.58	1.59	1.58	1.57	1.55
¥/US$	83	83	84	84	84	84	85	87	89	92	94

U.S. Rates

The Minutes from the December 14 FOMC meeting showed that the Fed still has a strong commitment to its $600 billion QE program, along with the (up to) $300 billion reinvestment program, despite evidence of mounting economic momentum and the massive back-up in bond yields. The former suggests that Treasury purchases might no longer be needed as much; however, some FOMC members *"had a fairly high threshold for making changes to the program."* The latter portends an early QE end owing to lack of effectiveness; however a number of members were satisfied that they were *"helping to keep longer-term yields lower than would otherwise be the case."*



Source: U.S. Federal Reserve Board

Also assisting the status quo, the incoming group of regional FOMC voters appear to be more pro-QE than the outgoing group. Among the outgoing class, KC's Hoenig dissented every chance he got last year. In their post-QE speeches, Cleveland's Pianalto, Boston's Rosengren and St. Louis' Bullard all said their support for QE was based on a weighing of pros and cons (with Rosengren particularly sceptical of the cons). The most hawkish among the incoming class is Dallas' Fisher (he argued against QE but accepted it as *"a bridge loan to fiscal sanity"*); Philly's Plosser is sceptical of the pros. However, Minneapolis' Kocherlakota has been an unabashed supporter of QE, while Chicago's Evans is an unabashed supporter of price level targeting (and thus of measures such as QE that are designed to raise shorter-run inflation expectations).

ECONOMIC RESEARCH

Rates *Scenario*

Interest Rate Forecasts
Percent (averages)

	Actual	2011			2011			2012			
	Dec	Jan	Feb	Mar	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Cdn. Yield Curve											
Overnight	1.00	1.00	1.00	1.00	1.15	1.50	1.85	2.35	2.85	3.35	3.75
3 month	0.99	1.00	1.00	1.00	1.15	1.50	1.85	2.35	2.85	3.35	3.75
6 month	1.12	1.15	1.15	1.15	1.35	1.70	2.00	2.50	3.00	3.50	3.95
1 year	1.36	1.45	1.45	1.45	1.60	2.10	2.55	2.95	3.30	3.65	3.95
2 year	1.67	1.75	1.75	1.75	1.90	2.55	3.15	3.45	3.65	3.85	4.00
3 year	1.89	1.95	1.95	1.95	2.10	2.65	3.20	3.50	3.70	3.90	4.10
5 year	2.45	2.55	2.55	2.50	2.65	3.00	3.40	3.65	3.80	4.00	4.15
7 year	2.75	2.85	2.80	2.80	2.90	3.20	3.50	3.70	3.90	4.05	4.25
10 year	3.20	3.25	3.25	3.20	3.25	3.45	3.65	3.80	3.95	4.10	4.30
30 year	3.62	3.65	3.65	3.60	3.65	3.80	4.00	4.15	4.25	4.40	4.55
1m BA	1.11	1.15	1.15	1.15	1.35	1.65	2.00	2.50	3.00	3.50	3.90
3m BA	1.19	1.25	1.25	1.25	1.40	1.75	2.10	2.60	3.10	3.60	4.00
6m BA	1.32	1.40	1.40	1.40	1.55	1.90	2.25	2.75	3.25	3.75	4.15
12m BA	1.57	1.65	1.60	1.60	1.80	2.30	2.75	3.15	3.50	3.85	4.15
Prime Rate	3.00	3.00	3.00	3.00	3.15	3.50	3.85	4.35	4.85	5.35	5.75
U.S. Yield Curve											
Fed funds	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.58	1.10	1.50	2.00
3 month	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.59	1.10	1.50	2.00
6 month	0.19	0.19	0.19	0.19	0.19	0.19	0.20	0.65	1.15	1.55	2.05
1 year	0.29	0.31	0.30	0.29	0.37	0.65	0.93	1.40	1.85	2.25	2.70
2 year	0.62	0.70	0.68	0.67	0.83	1.40	1.95	2.40	2.80	3.20	3.60
3 year	0.99	1.15	1.10	1.10	1.25	1.75	2.25	2.70	3.10	3.50	3.90
5 year	1.93	2.15	2.05	2.00	2.10	2.50	2.90	3.30	3.65	4.00	4.35
7 year	2.66	2.85	2.75	2.70	2.75	3.05	3.40	3.75	4.05	4.35	4.65
10 year	3.29	3.50	3.40	3.30	3.30	3.60	3.85	4.10	4.35	4.55	4.80
30 year	4.42	4.55	4.45	4.30	4.30	4.50	4.75	4.95	5.10	5.30	5.45
1m LIBOR	0.26	0.25	0.25	0.25	0.25	0.25	0.25	0.70	1.20	1.60	2.10
3m LIBOR	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.75	1.25	1.65	2.15
6m LIBOR	0.46	0.45	0.45	0.45	0.45	0.45	0.45	0.90	1.40	1.80	2.30
12m LIBOR	0.78	0.80	0.75	0.75	0.85	1.10	1.40	1.85	2.30	2.70	3.15
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.60	4.10	4.50	5.00
Other G7 Yields											
ECB Refi	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.35	1.65	2.25	3.00
10yr Bund	2.90	2.90	2.80	2.75	2.95	3.30	3.60	3.85	4.10	4.30	4.55
BoE Repo	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.90	1.40	2.00	2.75
10yr Gilt	3.50	3.40	3.35	3.25	3.50	3.90	4.25	4.55	4.80	5.05	5.25
BoJ O/N	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
10yr JGB	1.19	1.15	1.15	1.10	1.15	1.25	1.35	1.45	1.55	1.65	1.70

BMO Capital Markets

Undertaking

Undertaking LT1.11

To provide the bank document and to explain precisely what information was gleaned from the document and how the 0.2 was derived.

Response

Further to Exhibit K5-2-3 and Board Staff Technical Conference Question No. 22, we have attached a copy of the January, 2011 BMO Capital Markets "Rates $cenari%". On page 8 of this document they reflect interest rate forecasts for the Canadian Yield Curve. Under the 10 and 30yr curves, we have highlighted the forecast information used to determine the 0.2% increase in rates during 2011 and rising up approximately 1.00% by the end of 2012. As noted in K5-2-3, Hydro Ottawa Limited ("Hydro Ottawa") used the low end of this increase to forecast its rates for 2011 and 2012.

The Ontario Energy Board's (the "Board") Cost of Capital Report of December 11, 2009 states "*In general, The Board is of the view that the onus is on the electricity distribution utility to forecast the amount and cost of new or renewed long-term debt*"

This is further supported by the Board's decision to approve the full settlement of Toronto Hydro's Long-Term Debt Rate of 5.37% in EB-2010-0142 which included forecast rates of 5.75% late in 2011 based on underlying yield curves.

Hydro Ottawa has followed the guidelines of the Cost of Capital Report and has been prudent in providing a forecast cost of new debt.

5. CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 5.2 - Is the proposed long term debt rate appropriate?

<u>Board Staff Question #51 – Ref: Exh E1-1-1 and Exh A3-1-1, Attachment I</u>

Hydro Ottawa states that it receives its financing through the Holding Company. At p2 of Exh E1-1-1, it states:

> All external debt is managed by the Holding Company on behalf of its affiliates to achieve favourable market rates and to maintain a strong credit rating at the parent company level. Hydro Ottawa states that it benefits from this financing arrangement with competitive pricing as it could not place external long term debt in the smaller incremental tranches that it normally receives from the Holding Company. The cost of debt is passed onto Hydro Ottawa on the same terms as the parent when external financing secured by the Holding Company is targeted for Hydro Ottawa, or, in the absence of external financing, the deemed rates as determined by the Board Report on CoC and IRM that are in effect at the time of the financing transaction. Consistent with current and past practice, amortized issuance costs and ten basis points for administration is included in the debt rate.

Please clarify the transaction and administration costs related to long term debt summarized in Table 1 of Exh E1-1-1.

a) For each of the debt instruments documented in Table 1 of Exh E1-1-1, please identify whether the documented cost of debt has been determined based on:
    i. The terms of parent company financing plus amortized issuance costs and 10 basis points (0.1%) for administration; or
    ii. The Board issued deemed debt rates.
b) The debt issued on July 1, 2005 at 5.14% is noted in the 2008 Financial Statements of Hydro Ottawa Holdings at 4.93%. Is the difference of 0.21% composed of 0.1% for administration costs and 0.11% for amortized issuance costs? Please provide a detailed derivation of the costs.
c) Please provide the same analysis requested in b) for the other promissory note

issued on July 1, 2005, and the notes issued on December 20, 2006, December 21, 2009, April 1, 2010 and June 1, 2010.

d) Please explain any differences in the levels of transaction costs and administration costs for long term debt prior to and including June 1, 2010.

Response

a) Table 1 summarizes the terms of each promissory note as requested in items a) through d).

Table 1

Date of Issuance	Principal ($000's)	Actual or Deemed	Interest Rate	Issuance Costs	Admin. Costs	Total Rate
July 1, 2005	200,000	Actual	4.93 %	0.11 %	0.10 %	5.140 %
July 1, 2005	32,185	Deemed	5.900 %	NIL	NIL	5.900 %
Dec. 20, 2006	50,000	Actual	4.968 %	0.25 %	0.10 %	5.318 %
Dec. 21, 2009	15,000	Deemed	5.75 %	NIL	0.10 %	5.85 %
April 30, 2010	15,000	Deemed	5.87 %	NIL	0.10 %	5.97 %
July 5, 2011	15,000	Deemed	5.45 %	0.10 %	0.10 %	5.65 %
Sept. 1, 2011	15,000	Deemed	5.55 %	0.10 %	0.10 %	5.75 %
Dec. 1, 2011	15,000	Deemed	5.55 %	0.10 %	0.10 %	5.75 %
July 1, 2012	15,000	Deemed	5.55 %	0.10 %	0.10 %	5.75 %

5. CAPITAL STRUCTURE AND COST OF CAPITAL

Issue 5.1 - Is the proposed capital structure, rate of return on equity and short term debt rate appropriate?

VECC Question #45 - Ref: Exhibit E1, Tab 1, Schedule 1, page 4

a) Please explain the statement made at page 4: "Hydro Ottawa benefits from this financing arrangement with competitive pricing as it could not place external long term debt in the smaller incremental tranches that it normally receives from the Holding Company." Why can Hydro Ottawa not place external long term debt in small increments?

b) How does Ottawa Hydro determine that it gets a "competitive pricing?" In respect to Table 1 (E1/T1/S1/pg.3). Please provide the comparable rates that were considered in making that statement.

c) Since Ottawa Hydro is by far the predominant entity of the Holding Company how does any benefit arise?

d) Please provide the 2012 costs related that arise out of the 10 basis points "administration costs" paid to the Holding Company.

Response

a) The Canadian bond market becomes more illiquid the smaller the debt issuance. Any transaction under $100 million will generally require a liquidity premium. The lower the amount of issuance, the higher the liquidity premium. As well, the smallest tranche that could be generally placed in the market is approximately $50M. The Holding Company provides smaller tranches to Hydro Ottawa Limited (Hydro Ottawa") without this premium attached to it as it will issue external debt when warranted.

b) Hydro Ottawa either receives a debt rate based on the actual external cost of financing at the Holdco level or a deemed rate that is a proxy to a market rate for "A" rated utilities. As noted in part a) above, a premium, which is usually required for smaller issuances, has not been included in any of the ongoing smaller tranches issued by Hydro Ottawa through the Holding Company. These smaller tranches avoid having excess cash on the balance sheet and carrying costs for Hydro Ottawa while maintaining the target capital structure.

c) Please refer to part b) above.

d) The administration fee covers expenses incurred by the Holding Company which are not covered in the regular service level agreement. These include credit agency fees, ongoing communications / meetings with the credit rating agencies, ongoing meetings / communications with investment bankers, ongoing meetings / communications with cash management & credit facility bankers, etc. Executive time for presentation preparation, meetings, and travel are typical costs that are covered by the financing administration fee.

4. OPERATING COSTS

Issue 4.1 - Is the overall OM&A forecast for the test year appropriate?

Board Staff Question #33 - Ref: Exh D1-1-1 Ref: Hydro Ottawa EB-2010-0133, Exh D1-1-2

The table below summarizes OM&A expense for the period 2008 to 2012. Hydro Ottawa states that there can be some inconsistency in the split between operations and maintenance expense, and that operations and maintenance expense should be considered in their totality.

a) Please confirm that the data entries in the table below are correct.
b) The data indicate that in 2008, actual OM&A expense was lower than 2008 Board approved for every OM&A expense category.
   i. The variance explanation at Exh D2-1-1 indicates that $0.6M of the variance is related to unplanned staff vacancies. Would the vacancy allowance of 3% incorporated in the current workforce plan address the variance?
   ii. The variance explanation indicates that another $0.6M of the variance is related to the impact of smart meters. Has the historical experience been reflected in the current application?
c) Staff notes that the 2010 actual OM&A expenses of $53,350,685, are lower than that forecast in Hydro Ottawa's 2011 cost of service application, $59,644,369. Please explain the factors that contributed to these differences.

	2008 Approved	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Forecast	EB-2010-0133	
							2010 Bridge	2011 Forecast
Operations	13,062,448	11,752,560	11,364,065	11,971,416	12,061,906	11,883,322	14,996,358	15,269,439
Maintenance	5,111,153	5,183,949	5,171,079	5,663,033	8,462,994	9,274,548	6,006,658	6,086,041
SubTotal	**18,173,601**	**16,936,509**	**16,535,144**	**17,634,449**	**20,524,900**	**21,157,870**	**21,003,016**	**21,355,480**
%Change (year over year)			-2.4%	6.6%	16.4%	3.1%		
%Change (Test Year vs Last Rebasing Year - Actual)						24.9%		
Billing and Collecting	11,716,819	10,365,089	10,233,636	9,142,479	11,925,750	12,085,194	10,579,743	10,840,730
Community Relations	4,759,852	4,588,888	4,594,942	4,932,698	6,093,455	6,911,671	5,459,667	6,607,061
Admin and General	20,679,521	19,738,418	20,670,993	21,641,059	22,790,434	23,736,696	22,601,943	24,163,018
SubTotal	**37,156,192**	**34,692,395**	**35,499,571**	**35,716,236**	**40,809,639**	**42,733,561**	**38,641,353**	**41,610,809**
%Change (year over year)			2.3%	0.6%	14.3%	4.7%		
%Change (Test Year vs Last Rebasing Year - Actual)						23.2%		
Total	**55,329,793**	**51,628,904**	**52,034,715**	**53,350,685**	**61,334,539**	**63,891,431**	**59,644,369**	**62,966,289**
			0.8%	2.5%	15.0%	4.2%		

Response

a) Entries in the table are correct. Actual values by USofA account groupings in the table agree to submitted values to the Ontario Energy Board (the "Board") by USofA account and are consolidated into the groupings per the Board guidelines.

b)

i. Yes the updated vacancy allowance assumption would have addressed the variance. The vacancy assumption of 3% included in the 2012 OM&A is equal to $2.5M.

ii. Yes. The Smart meter program is winding down. Expenses related to the legacy meters have been removed and only expenses for Smart meters are included.

c) Time of Use ("TOU") and MDMR program costs planned but not incurred in 2010 are required in 2011, and maintenance costs were lower than expected on new meters. Total reduction in spending was $1.2M for 2010. Delays in hiring and vacancies account for $2.1M. Refer to D2 Tab 1 Schedule 3 for details. Favourable one time savings in bad debts expense, consulting, communications, and training account for the balance of the variance.

Table 3 – Apprentices Hired and Retained by Trade (Hired/Retained)

Position Title	2005	2006	2007	2008	2009	2010	Total
Powerline Maintainer	8/6	0	10/9	8/8	0	0	26/23
Cable Jointer	0	6/6	0	4/4	0	0	10/10
System Operator	0	2/1	4/3	5/4	0	2/1	13/9
Stations Electrician	0	2/0	2/1	1/1	3/3	3/2	11/7
Metering Technician	0	0	0	0	0	1/1	1/1
TOTAL Hired	8	10	16	18	3	6	61
TOTAL Retained	6	7	13	17	3	4	50

Hydro Ottawa's workforce planning model is multi-faceted and examines the following factors for each trades and technical group:

- Attrition through retirements, resignations, disability, death, etc.,
- Organic growth in customer base,
- Asset management plan work requirements and major projects, and
- Anticipated dates apprentices will obtain their journeyperson status.

The workforce planning model assumes that 75 percent of those eligible to retire will retire on their eligibility date or shortly thereafter utilizing earned and unused vacation leave as a transition into retirement.

For 2011 and 2012, the Cable Jointer and System Operator trades are well positioned to address operational needs. The Powerline Maintainer, Station Electrician and Metering Technician trades require the additional apprentices which have been hired or are in progress of being recruited in 2011:

- 11 Powerline Maintainers – 3 second year apprentices who have graduated from the Powerline Technician Programs of Cambrian and Conestoga College and 8 first year apprentices,
- 2 Stations Electricians – to replace apprentices who have not been retained, and
- 4 Metering Technicians – as required based on the workforce planning model.

Board Staff 14a

Year	Eligible In Year	Eligible Cumulative	Actual Retirement	Balance Cumulative
Prior				7
2008	7	14	4	10
2009	18	28	12	16
2010	21	37	11	26
2011 YTD	11	37	8	29
Totals	**57**		**35**	

Note: Of 35 actual retirements since 2008, 72% have retired within 6 months of eligible date. 29 remain eligible cumulatively, primarily from 2010 and 2011.

Of the 8 retirements in 2011 to date, 2 became eligible in 2011, 5 in 2010, and 1 in 2008
3 additional staff have provided notice to retire.

Attachment AC - Employee Compensation Breakdown (Appendix 2-K)

Hydro Ottawa Limited
EB-2011-0054
Exhibit D3
Tab 1
Schedule 1
Attachment AC
Filed: 2011-06-17
Page 1 of 1

Number of Employees (FTEs & Temporary)	Last Rebasing Year 2008	Historical Year 2009	Historical Year 2010	Bridge Year 2011	Test Year 2012
Number of Full-Time Employees					
Executive	6	6	6	5	5
Management	96	101	102	107	127
Non-Union	39	37	38	38	41
Union	388	402	405	407	425
Total	529	546	551	557	598
Number of Temporary Employees					
Executive	0	0	0	0	0
Management	1	0	0	2	2
Non-Union	5	3	3	1	1
Union	4	4	5	5	5
Total	10	7	8	8	8
Total Salary and Wages ($)					
Executive	791,698	805,687	829,088	701,341	730,466
Management	8,862,186	9,370,149	9,714,911	10,599,039	13,337,017
Non-Union	2,787,422	2,622,382	2,701,294	2,745,259	3,141,466
Union	24,242,591	25,879,165	27,017,395	27,556,918	29,730,587
Total	36,683,897	38,677,382	40,262,688	41,602,556	46,939,536
Total Benefits ($)					
Executive	177,908	188,093	197,543	182,068	189,350
Management	1,803,966	1,945,918	2,013,229	2,554,404	3,162,336
Non-Union	572,534	559,210	582,860	740,467	838,540
Union	5,507,852	5,943,148	6,191,629	7,444,097	7,919,182
Total	8,062,261	8,636,370	8,985,262	10,921,036	12,109,408
Total Compensation (Salary, Wages, & Benefits) ($)					
Executive	969,607	993,780	1,026,631	883,409	919,816
Management	10,666,152	11,316,067	11,728,141	13,153,443	16,499,353
Non-Union	3,359,956	3,181,592	3,284,154	3,485,726	3,980,006
Union	29,750,444	31,822,313	33,209,024	35,001,015	37,649,769
Total	44,746,158	47,313,752	49,247,950	52,523,592	59,048,944
Compensation - Average Yearly Base Wages ($)					
Executive	131,950	134,281	138,181	143,743	149,493
Management	92,094	92,499	95,058	98,252	102,600
Non-Union	72,401	70,684	70,530	72,303	76,747
Union	62,447	64,355	66,660	67,283	69,232
Total	69,354	70,838	73,072	74,213	77,530
Compensation - Average Yearly Overtime ($)					
Executive	0	0	0	0	0
Management	0	0	0	0	0
Non-Union	0	0	0	0	0
Union	5,295	6,605	6,358	6,025	6,025
Total	5,295	6,605	6,358	6,025	6,025
Compensation - Average Yearly Incentive Pay ($)					
Executive	34,692	37,676	40,859	34,895	36,290
Management	5,970	11,757	11,902	11,328	12,741
Non-Union	3,245	0	0	0	0
Union	0	0	0	0	0
Total	6,949	17,978	17,978	15,129	15,479
Compensation - Average Yearly Benefits ($)					
Executive	29,651	29,549	32,924	36,414	37,870
Management	17,891	18,186	18,815	22,407	23,425
Non-Union	9,871	10,754	10,997	17,630	18,634
Union	12,899	14,017	14,136	17,152	17,716
Total	13,619	14,620	14,876	18,355	19,160
Total Compensation ($)	49,538,906	51,881,632	52,658,511	57,003,607	63,651,951
Total Compensation Charged to OM&A ($)	35,756,345	36,302,775	37,388,495	41,251,768	46,391,375
Total Compensation Capitalized ($)	14,805,466	16,139,120	15,809,921	16,317,807	17,849,184

4.0 AVERAGE ANNUAL OVERTIME

Table 5 summarizes the average overtime paid per employee.

Table 5 – Average Annual Overtime

	2008 Approved	2009 Actual	2010 Actual	2011 Bridge	2012 Test
Unionized	$5,295	$6,605	$6,358	$6,025	$5,923

For non-unionized and management staff, overtime is not applicable except in highly unusual and extenuating circumstances. No amounts are budgeted for 2011 or 2012 for non unionized and management staff.

5.0 AVERAGE ANNUAL INCENTIVE PAY

Table 6 summarizes the average annual incentive (variable) pay for executive, management and non-unionized staff.

Table 6 – Average Annual Incentive Pay

	2008 Approved $	2009 Actual $	2010 Actual $	2011 Bridge $	2012 Test $
Executive/senior management	$34,692	$37,676	$40,859	$34,895	$36,290
Management	5,970	11,757	11,902	11,328	12,741
Non-unionized	3,245	0	0	0	0

In 2007, the company adopted a new compensation plan which moved a portion or all of the compensation from the incentive plan for non-unionized and some management employees to base wages. The transition to this new plan occurred in 2007 and 2008 resulting in the decrease shown for the incentive pay in 2008, and the full elimination for non unionized staff in subsequent years.

Hydro Ottawa's actual OM&A spending for 2008 was very close to the amount included in Hydro Ottawa's 2008 Electricity Distribution Rate ("EDR") Application. The labour category has now been broken down to reflect outside services including contract employees. Included within outside services are costs for repairing customer-owned property as a result of meter deployment. The amount for this work was less than $100k each year. In 2009, Hydro Ottawa began developing comprehensive plans for the roll out of TOU rates. Additional staff, both permanent and on contract, was added to support the initiative. The volume of data being managed increased significantly as more meters were converted and additional staff was required to manage and analyze the data. The 2011 budget also reflects the one time increase in outside services costs related to call volume as the TOU rates roll out to all customers.

In 2010, the activity related to customer communications increased significantly over 2009. In late 2009, Hydro Ottawa formed a dedicated team for change management to document process changes and identify impacts, develop and implement training, communicate to staff and ensure external communications are coordinated with the roll out. An overall customer communications plan has been developed including materials such as a welcome package to TOU rates. The welcome package directs customers to the web site developed as part of this project that will assist customers in understanding their bill and reviewing their consumption. These costs are budgeted for 2011 ~~will increase~~ as TOU rates roll out to all customers and as a result the 2011 Budget is higher than any other year.

Starting in 2009 and increasing in 2010 are the costs of information technology maintenance contracts including new Oracle software required for TOU, web services support, contracts with IBM for supporting integration to Hydro Ottawa's CIS, support for an upgrade to Hydro Ottawa's settlement system (Lodestar) and a support contract for the Elster system. The 2011 Budget incorporates a Disaster Recovery Plan that includes an offsite location.

11. MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS

Issue 11.1 - Is the proposed revenue requirement determined using modified IFRS appropriate?

Board Staff Question #81 - Ref: Exh J-1-1, p9

Has the applicant 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.

Response

Hydro Ottawa Limited ("Hydro Ottawa") has consulted with professional advisors regarding the change in capitalization of overhead throughout the IFRS transition project. Hydro Ottawa is utilizing the external audit firm as the IFRS advisory firm. Consultations have occurred with the IFRS advisory team but not yet with the external audit team. While there is overlap of external audit staff on the IFRS advisory team, formal consultation with the external audit team will occur during Q4 of 2011.

Technical Conference Question

c) [J2-1-1, J2-1-2, and K11, 11.1, Energy Probe #64] Please recalculate Tables 1 through 3 of J2-1-1, and the continuity schedules in J2-1-2, and Tables 1 through 6 of the Energy Probe IR response, using the Typical Lives set out in the Kinectrics Report.

Response

Hydro Ottawa Limited (Hydro Ottawa) has undertaken a rudimentary illustrative analysis in order to respond to School Energy Coalition's (SEC) request for information that compares components and service lives determined by Hydro Ottawa for the purposes of depreciation under International Financial Reporting Standards (IFRS) with the Typical Useful Lives set out in the Kinectrics Report.

As discussed with counsel for the SEC, Hydro Ottawa's IFRS analysis was the result of many months of effort that involved, among other things, the determination of IFRS compliant asset components to which costs should be assigned, applicable service lives, and the allocation of opening balance sheet costs to such components. The analysis was completed by Hydro Ottawa accountants, engineers and operating staff, and reviewed by IFRS project partner Ernst & Young.

In order to provide the information sought by SEC, Hydro Ottawa's engineering staff applied judgment as to how to allocate opening net book values to the full range of Kinectrics asset components, even though many of the components are not applicable to Hydro Ottawa's circumstances. Modelling worksheets were expanded to allow for additional components, allocation percentages were estimated and the depreciation models were re-run. The result of this work is by no means a rigorous and accurate calculation and, in any event, Hydro Ottawa does not accept that the comparison that SEC seeks to make to the Kinectrics Report is either appropriate or relevant. Subject to these comments, the information sought by SEC is provided as Attachment 1.

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List of Components with differing depreciation lives between Hydro Ottawa and Kinectrics Typical Life

	Hydro Ottawa				Kinectrics		One to One Relationship			One to Many Allocation			
	Component name	Related UsofA	Life	NBV $$$ Opening Balance Sheet	Component Name	Kinectrics Typical life	Actual	Using Kinectrics Lives	Variance	Actual	Using Kinectrics Lives	Variance	Allocation
1	Line Transformers Overhead & Undergrounc	1850	30	31,115,669	OH Transformers & Voltage Regulators	40				2,220,575	1,525,203	(695,372)	100% @ 40 yrs
					Station Service Transformei	45							
					Pad-Mounted Transformers	40							
2	U/G Polymer Insulated Cable	1845	35	30,447,584	Primary Ethylene-Propylene Rubber (EPR) Cable:	25				2,338,961	2,162,158	(176,803)	60% @ 40 yrs, 40% @ 25 yrs
					Primary Non-Tree Retardant (TR) Cross Linked	25							
					Primary Non-TR XLPE Cables - In Duct	25							
					Primary TR XLPE Cables - Direct Burlec	30							
					Primary TR XLPE Cables - In Duct	40							
3	U/G Switchgear and Reclosers	1845	25	10,576,568	Pad-Mounted Switchgear	30	905,513	595,773	(309,740)				
4	Vault Switchgear and Reclosers	1845	30	2,090,705	UG Vault Switches	35	126,986	97,712	(29,273)				
5	U/G PILC Cable	1845	60	12,310,233	Primary Paper Insulated Lead Covered (PILC)	65	336,753	304,313	(32,440)				
6	O/H Conductors & Non-Automated Devices	1835	45	34,028,029	OH Conductors	60	1,063,383	762,244	(301,139)				
7	O/H Automated Devices	1835	25	4,492,287	OH Line Switch	45				386,073	194,724	(191,349)	100% at 40 yrs
					OH Line Switch Motor	25							
					OH Line Switch RTU	20							
					OH Integral Switches	45							
					Reclosers	40							
8	Other Stn. Equip. >50kV	1815	25	10,690,313	Station DC System - Overall	20	701,120	873,130	172,010				
9	Other Stn. Equip. < 50 kV	1820	25	9,905,464	Station DC System - Overall	20	1,006,110	1,138,236	132,126				
10	Station Switchgear >50kV	1815	40	20,737,464	Station Metal Clad Switchgear - Overal	40				710,957	710,957	-	100% @ 40 yrs
					Station Independent Breakers	45							
					Station Switch	50							
					Electromechanical Relays	35							
					Rigid Busbars	55							
					Steel Structure	50							
11	Station Switchgear <50kV	1820	40	13,224,604	Station Metal Clad Switchgear - Overal	40				1,002,276	1,002,276	-	100% @ 40 yrs
					Station Independent Breakers	45							
					Station Switch	50							
					Electromechanical Relays	35							
					Rigid Busbars	55							
					Steel Structure	50							
12	U/G Conduit and cable chambers	1840	40	50,093,508	UG Foundations	55				2,171,120	1,384,478	(786,642)	26% @ 50 yrs, 54% at 55 yrs, 20% at 60 yrs
					UG Vaults - Overall	60							
					Ducts	50							
					Concrete Encased Duct Banks	55							
					Cable Chambers	60							
13	Services	1855	45	38,245,623	Secondary PILC Cables	75				1,383,394	1,900,605	517,211	0% @ 75 yrs, 50% at 35 yrs, 50% at 40 yrs
					Secondary Cables - Direct Buried	35							
					Secondary Cables - In Duct	40							
14	SCADA RTU,Relays,Communication Equipment	1980	15	6,635,386	Solid State Relays	30				889,531	548,045	(341,486)	90% @ 20 yrs, 10% at 30 yrs
					Digital & Numeric Relays	20							
					Remote SCADA	20							
	TOTALS						4,139,865	3,771,409	(368,456)	11,102,887	9,428,446	(1,674,441)	

Components that do not require a further breakdown of the opening balance sheet NBV (6 out of 14)

2. 3 Asset Disposals

IFRS requires recognition of gains or losses on the disposal of PP&E immediately into income as opposed to the current practice of deferral in accumulated depreciation for pooled assets. The Board's IFRS Guidance states

> "where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the disposal 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..."

Hydro Ottawa does not have sufficient historical data for reliable trend analysis on which to base a forecast of the amount of gains or losses expected as a result of derecognizing pooled assets.

Gains can only arise where proceeds of sales are received; losses arise when the NBV on the date of disposal is greater than $Nil. For example, if a pole were knocked down by a storm, the NBV of that specific asset would be shown as a loss on disposal and as noted above, reclassified to depreciation expense for MIFRS. A new pole would have a higher net book value than an older pole and thus a higher loss.

Losses on pooled asset disposals will largely result from early asset disposals due to unforeseen / unplanned events on which Hydro Ottawa does not have any data to support an accurate forecast. Planned replacements only occur when the asset has reached the end of its useful life thus where the NBV is $Nil.

Due to the reasons noted above, nothing has been included in this rate application as estimation of gains or losses for disposals of pooled assets. Hydro Ottawa is requesting a new deferral account to capture these gains and losses on pooled assets (Refer to Exhibit J4-1-1).

11. MODIFIED INTERNATIONAL FINANCIAL REPORTING STANDARDS

Issue 11.2 – Are the proposed new MIRFS deferral and variance accounts appropriate?

<u>Board Staff Question #96 - Ref: Exh J4-1-1, Attachment AZ and Staff Discussion Paper – Transition to IFRS - Implementation in an IRM Environment (March 2011)</u>

As per the staff discussion paper:

> Utilities who expect to experience a large cost impact upon transition to IFRS for non-PP&E related items may apply to the Board on an individual basis for appropriate relief.

Hydro Ottawa states that as a result of $2.7 million actuarial losses from the actuarial valuation conducted on January 1, 2011, a deferral account to capture the opening balance adjustment is required for pensions.

a) What account number does Hydro Ottawa propose to use in the USoA?
b) What are the proposed journal entries to be recorded in this account?
c) When does Hydro Ottawa plan to ask for its disposition?
d) How does Hydro Ottawa plan to allocate this amount by rate class?
e) What new or additional information is available that would improve the Board's ability to make a decision to approve the recording of these costs or fees in a deferral account?

Response

a) Hydro Ottawa Limited ("Hydro Ottawa") proposes that the Ontario Energy Board assign a new USoA account within the 1500 range for this deferral account.

b) The proposed journal entries to be recorded in this account would be as follows:

DR	Regulatory Asset	2.8M	
CR	Benefit		2.8M

To set up the Liability

DR	Distribution Revenue	2.8M	
CR	Regulatory Asset		2.8M

To record the collection from customers.

c) Hydro Ottawa proposes to ask for disposition of this account at the first Cost of Service application after the account has been audited at the end of December 2012.

d) Hydro Ottawa would propose that this account would be allocated to rate classes based on Distribution Revenue.

e) No new or additional information on this proposed deferral account is available at this time

PROPOSED NEW MIFRS DEFERRAL AND VARIANCE ACCOUNTS

1.0 APPROVAL FOR NEW DEFERRAL AND VARIANCE ACCOUNTS

Hydro Ottawa Limited ("Hydro Ottawa") is seeking the Ontario Energy Board's (the "Board") approval for three new deferral accounts as part of the Modified International Reporting Standards ("MIFRS") portion of the rate application.

1.1 Deferral Account in Relation to PP&E Components of Rate Base

Hydro Ottawa is requesting approval for a deferral account to capture the difference in the closing Net Book Value ("NBV") of Property, Plant and Equipment ("PP&E") between Canadian Generally Accepted Accounting Principles ("CGAAP") and MIFRS as at December 31, 2011. Hydro Ottawa is adopting International Financial Reporting Standards ("IFRS") on January 1, 2012 but in order to present comparative financial information, it must effectively adopt IFRS at the beginning of the prior year and this is commonly referred to as the transition date or opening balance sheet date. Since the MIFRS PP&E is used as the rate base going forward, it is important for the continuity of rate base that the 2011 CGAAP versus MIFRS differences be recovered or refunded. Hydro Ottawa calculated this difference as illustrated in Appendix A in the Board's *Staff Discussion Paper – Transition to IFRS – Implementation in an IRM Environment (EB-2008-0408)* dated March 31, 2011 referred to as the Staff Discussion Paper throughout this Exhibit. The difference between CGAAP ending NBV and MIFRS ending NBV as at December 31, 2011 is $123k as shown in Attachment AZ. Hydro Ottawa is proposing that the balance be cleared on the basis of the forecast value over a four year period, consistent with the illustrative example in the above noted Staff Discussion Paper.

1.2 Deferral Account in Relation to Pensions

Hydro Ottawa is requesting approval for a deferral account to capture the opening balance sheet adjustment required to pensions as a result of converting to IFRS. As discussed in Exhibit J1-1-1, on January 1, 2011, a liability of approximately $2.8M is required to be set up to recognize all the cumulative actuarial losses at the date of transition to IFRS. This adjustment will flow through opening retained earnings. Under CGAAP, this amount would have been recovered through rates through OM&A as a portion of this amount was recognized as an expense each year. In the Staff Discussion Paper, the Board staff submitted "that a generic account to capture Pension and Other Post Employment Benefits ("P&OPEB") differences driven by the transition to IFRS is not required". The Board staff also stated that "utilities who expect to experience a large cost impact upon transition to IFRS for non-PP&E related items may apply to the Board on an individual basis for appropriate relief". As this is a significant amount for Hydro Ottawa, individual relief is being sought through this request.

1.3 Deferral Account in Relation to Asset Disposals

Hydro Ottawa is also requesting approval for a deferral account to capture gains or loss on disposals of pooled assets which is now required under IFRS. As discussed in Exhibit J1-1-1, Hydro Ottawa currently does not have the data to provide an accurate estimation of these gains or losses. Under MIFRS, these gains or losses on pooled assets would be identified separately and reclassified to depreciation expense. When gains or losses arise on pooled assets, amounts would be recorded in this deferral account. In the Staff Discussion Paper, Board staff indicate that "the account was suggested as a generic account on the basis that utilities have no experience in forecasting the extent of such losses and, as such, rebasing in the short term would be inaccurate. Staff submits that such a variance account would likely be a temporary measure that reduces the risk to utilities and ratepayers until the forecasting of the gains or losses improves with experience. However, staff recommends that no such generic account be considered at this time, as the Board has no information as to whether most utilities will encounter material difficulties in forecasting these amounts". Hydro Ottawa does have material difficulty in forecasting this amount and is therefore seeking an individual deferral account.

Board sponsored depreciation study was issued in July of 2010. On November 8, 2010, an amendment to the July report was issued to address the delay in implementing IFRS until January 1, 2012. A letter was also issued on March 15, 2011 to address the use of IFRS in cost of service applications for 2012 rates. Lastly an *Addendum to the Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (EB-2008-0408)* was issued on June 13, 2011. Collectively this set of guidance is referred to as the Board's IFRS Guidance throughout this exhibit. The Board's IFRS Guidance uses the term Modified IFRS ("MIFRS") to refer to IFRS accounting, as modified by the Board for regulatory purposes.

1.2 Hydro Ottawa IFRS Conversion Project

Hydro Ottawa launched its formal IFRS conversion project in 2008. The project governance involves a steering committee consisting of senior level management and external advisors. Hydro Ottawa's key external advisor for the IFRS conversion project is Ernst & Young. Hydro Ottawa has assessed the financial impacts of adopting IFRS and is implementing new processes for its 2012 financial year. The areas with the greatest impact are rate-regulated accounting and accounting for property, plant and equipment ("PP&E") as well as the impact of initial adoption. Hydro Ottawa also expects a significant increase in the annual financial statement note disclosure under IFRS.

Hydro Ottawa is currently in the implementation phase and is on schedule to report under IFRS for 2012.

1.3 IFRS 1

IFRS 1 First-time Adoption of International Financial Reporting Standards ("IFRS 1") is a standard applied by entities during the preparation of their first set of IFRS financial statements. The objective of this standard is to ensure that the first financial statements:

"contain high quality information that:

(a) is transparent for users and comparable over all periods presented;