EB-2010-0132

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Hydro One Brampton Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2011.

BOARD STAFF

CROSS-EXAMINATION COMPENDIUM OM&A AND OTHER ISSUES

DECEMBER 6, 7 & 9, 2010

Vulnerable Energy Consumers Coalition Interrogatory #41

Reference: **Exhibit 4, Tab 1, Schedule 4.1**
Exhibit 4, Tab 2, Schedule 1.3
Exhibit 4, Tab 4, Schedule 8.0

a) Who currently is responsible for the Human Resource and Labour Relations functions at Brampton?

Response:

The Vice President of Finance and Administration is responsible for these functions at Hydro One Brampton

b) Please provide a schedule similar to Table 2 (Tab 4, Schedule 8.0) that describes the 2010 employee additions.

Response:

The following table summarizes a brief position description for the 2010 Employee Additions & Deletions:

2010 EMPLOYEE ADDITIONS	DESCRIPTION
Assistant Supervisor - Customer Accounts	• Provides support to Supervisor in reviewing daily adjustment register, weekly cheque refunds and monthly transformer allowance refunds. Makes suggestions to streamline processes and increase efficiencies, advises supervisor of staffing or work-related issues. Assists Smart Meter Clerk with investigation issues, estimating, and troubleshooting.
Building General Helper	• Assists Building Foreman and Service Centre Maintainer in building maintenance duties. Conducts janitorial duties as required. Participates in waste management, preventative maintenance and inspection programs as required.
Customer Accounts Representative	• Answers customer account inquiries. Prepares billing data and reviews edits. Processes billings and updated records. Prepares billing adjustments as required. Conducts follow up activities on accounts.
Engineering Technician	• Sources and assembles data related to asset vintage, quantity, and location using database and mapping technology. Develops asset monitoring techniques and field data collection programs. Prepares business cases to support asset sustainment or replacement programs. Develops asset maintenance and replacement schedules. Develops a five-year capital plan.
Fleet Mechanic	• Services and repairs vehicles, trailers, mobile equipment and hydraulic equipment. Repairs small portable equipment such as pumps, generators and tampers. Road testing and delivery of vehicles/trailers as required.
Line Apprentices (2)	• Maintenance and construction of overhead and underground distribution lines.
Outage Planning Coordinator	• Provides support for the scheduling committee, Engineering, Planning & Lines. Provides Operations a daily/weekly/monthly detailed work plan of required work protection, switching and/or outage requirements.
Project Engineer	• Accountable for the certification of Engineering, Technical Service and other department construction projects as required by Ontario Regulation 22/04. This will include deviation of approval for construction projects and the construction verification process. Also accountable for special projects as assigned to provide technical input in the form of design, review or implementation.
Software Developer	• Accountable for analysis, design, coding, testing, documentation, implementation and user training of new and existing computer software systems using a variety of hardware platforms, software languages and programs.

c) Why is Brampton planning on implementing CDM initiatives separate from the OPA (See Tab 4, Schedule 8.0)? What types of programs are anticipated?

Response:

Hydro One Brampton has been provided both a demand and energy target that must be achieved. The OPA is to provide a suite of programs that will be offered to all utilities which Hydro One Brampton will automatically offer to its customers. At this time it is not possible to determine if the targets could be met utilizing the OPA suite of programs alone. It may be necessary to develop or participate in other programs not offered by the OPA to ensure that Hydro One Brampton met its conservation targets. At this time it is not possible to quantify if any specific program(s) will be required or the associated costs of these programs.

d) With respect to Tab 4, Schedule 8.0, Table 1, please provide specifics regarding the New Programs and Increased Work Load giving rise to the need for the employee additions.

Response:

POSITION	No. of Hires	Position Rationale	Explanation for New Programs and Increased Workload
Accounts Receivable Analyst	1	R	
Assistant Supervisor – Customer Accounts	1	W	Increases in customers and call volume. Introduction of Smart Meter program has increased call volume.
Building General Helper	1	W	Building is aging therefore more work to be done.
Credit Representative	1	W	Increases in customers and call volume. Difficult economic time - more customers in collections.
Customer Accounts Representative	2	W	Increases in customers and call volume. Introduction of Smart Meter program has increased workload.
Drafting Supervisor	1	R	
Draftsperson	1	R	
Engineering Technician	2	R (1), P (1),	Introduction of Asset Management department.
Fleet Mechanic	1	S,W	Vehicles aging therefore more workload.
Health, Safety & Environment Coordinator	1	S,W	New legislation and legal requirements for documentation has increased workload.
Line Apprentice	3	S	
Human Resources Manager	1	W	Currently the V.P. of Finance & Administration oversees the H.R. department. Requirement to have an individual who may potentially Supervise HR and HSE and be able to do the Labour Relations function.
Conservation & Demand Management (CDM) Representative	1	W	Green Energy Act has created a demand for an Energy Specialist.
Outage Planning Coordinator	1	W	A need to coordinate the planning & outage workflow between Planning, Engineering, Lines and Operations departments.
Project Engineer	2	S	
(Smart Metering Supervisor)	-1	C	
Software Developer	1	S,W	Implementation of new computer software systems & programs.
TOTAL:	**20**		

EMPLOYEE ADDITIONS FOR 2010 BRIDGE AND 2011 TEST YEAR

Table 1, below, outlines the Hiring Schedule for each quarter for the bridge year (2010) and test year (2011). Under Position Rationale, 'P' indicates a New Program, 'R' indicates a Replacement Position, 'S' indicates an addition due to Succession Planning, 'W' indicates a position added due to Increased Workload and 'C' indicates a Completion of Program. Bridge (2010) and test year (2011) Hiring Schedule

The following table summarizes a brief position description for the 2011 Employee Additions & Deletions:

Table 1: Bridge (2010) and Test Year (2011) Hiring Schedule

POSITION	No. of Hires	Number of Hires by Quarter								Position Rationale
		2010				2011				
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	
Accounts Receivable Analyst	1		1							R
Assistant Supervisor – Customer Accounts	1			1						W
Building General Helper	1		1							W
Credit Representative	1					1				W
Customer Accounts Representative	2	1				1				W
Drafting Supervisor	1	1								R
Draftsperson	1		1							R
Engineering Technician	2	1	1							R (1), P (1),
Fleet Mechanic	1		1							S,W
Health, Safety & Environment Coordinator	1					1				S,W
Line Apprentice	3			2				1		S
Human Resources Manager	1						1			S,W
Conservation & Demand Management (CDM) Representative	1						1			W
Outage Planning Coordinator	1		1							W
Project Engineer	2		1				1			S
(Smart Metering Supervisor)	-1								-1	C
Software Developer	1		1							S,W
TOTAL:	**18**	**3**	**8**	**3**	**0**	**3**	**3**	**1**	**-1**	

2011 COST DRIVERS

Wages and Benefits $459,649

In 2011, the planned hiring of new incremental personnel at a cost of $254,516 will consist of:

1. Credit Representative (1st quarter)
2. Customer Accounts Representative (1st quarter)
3. Line Apprentice (3rd quarter)
4. Human Resources Manager (2nd quarter)
5. Conservation and Demand Management Representative (2nd quarter)

Wages are not planned to increase in 2011. There will be increases of $205,135 for staff movements including prior year additions, retirements, promotions, resignations and terminations.

Conservation and Demand Management $70,949

This increase is associated with the hiring of an additional position to ensure compliance and with the government's latest CDM targets.

Bad Debts $10,296

It is expected that bad debts will increase slightly due to customer growth.

Postage & Stationery $119,267

It is expected that Canada Post will increase postage rates and the pre-sorted postage. Customer growth will increase the postage expense.

Meter Reading $848,611

In 2011, is expecting to incur monthly meter reading costs directly from the MDR.

Tree Clearing $3,795

No significant variance is expected from the prior year for tree clearing.

Regulatory Expenses $100,000

The regulatory expenses are expected to be higher largely due to incremental costs expected to be incurred with this rate application. Intervener costs $50,000 and Legal costs $20,000.

2011 TEST YEAR VERSUS 2010 BRIDGE YEAR

5005 – Operations Supervision and Engineering

Operations supervision and engineering shows an increase of $362,593 due to the implementation of an Asset Management Group in 2010. The increase is due to salaries for the additional staffing requirements of the group, including an Asset Management Supervisor, an Asset Maintenance Technician and a Financial Analyst.

5065 – Meter Expense

Meter expense shows a decrease of $660,893 due to the transfer of smart metering software cost responsibility from the metering department to the Information technology department ($300,000). Hydro One Brampton also expects a reduction of failed meter base costs, which will be offset by incremental smart metering maintenance costs ($285,000).

5310 - Meter Reading Expense

Meter Reading Expense shows an increase of $848,611 in 2011 as all smart meter reading costs previously deferred from smart metering variance account 1556 will be expensed in this account to incorporate all costs associated with the MDMR.

2011 COST DRIVERS

Wages and Benefits $459,649

In 2011, the planned hiring of new incremental personnel at a cost of $254,516 will consist of:

1. Credit Representative (1st quarter)
2. Customer Accounts Representative (1st quarter)
3. Line Apprentice (3rd quarter)
4. Human Resources Manager (2nd quarter)
5. Conservation and Demand Management Representative (2nd quarter)

Wages are not planned to increase in 2011. There will be increases of $205,135 for staff movements including prior year additions, retirements, promotions, resignations and terminations.

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It is expected that Canada Post will increase postage rates and the pre-sorted postage. Customer growth will increase the postage expense.

Meter Reading $848,611

In 2011, is expecting to incur monthly meter reading costs directly from the MDR.

Tree Clearing $3,795

No significant variance is expected from the prior year for tree clearing.

Regulatory Expenses $100,000

The regulatory expenses are expected to be higher largely due to incremental costs expected to be incurred with this rate application. Intervener costs $50,000 and Legal costs $20,000.

Ontario Energy Board Interrogatory # 16

Ref: Exhibit 4 / Tab 2 / Schedule 1.1 – Summary of OM&A Expenses

On Page 1, Table 1 provides a summary of OM&A expenses for the period from 2006 to 2011.

a) Please use the same format as shown in Table 1 to provide the OM&A expenses based on CGAAP.

Response:

Exhibit 4, Tab 2, Schedule 1.1, Table 1 is revised and shown below based on CGAAP::

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year (BY) 2010	Variance BY 2010 - 2009 Actuals	Test Year (TY) 2011	Variance TY - BY
Operation	2,720,134	3,350,836	630,702	3,079,156	(271,680)	3,544,751	465,594	3,815,041	270,290	4,900,708	1,085,667	4,559,988	(340,720)
Maintenance	2,700,089	3,023,980	323,891	3,091,210	67,230	3,374,105	282,895	3,159,226	(214,879)	3,590,436	431,210	3,904,606	314,170
Billing and Collecting	3,512,796	3,775,564	262,768	3,820,263	44,699	4,324,468	504,205	4,897,921	573,454	4,632,782	(265,139)	5,656,663	1,023,881
Community Relations	256,376	1,018,450	762,075	797,999	(220,451)	371,587	(426,412)	363,138	(8,449)	570,000	206,862	640,000	70,000
Administrative and General	4,463,821	4,986,820	522,999	5,137,182	150,361	5,558,770	421,588	5,601,103	42,334	6,699,374	1,098,271	7,445,278	745,904
Total OM&A Expenses	13,653,216	16,155,651		15,925,811		17,173,680		17,836,429		20,393,300		22,206,535	
Variance from previous year			2,502,435		(229,840)		1,247,870		662,748		2,556,871		1,813,235
Percent change (year over year)			18.33%		-1.42%		7.84%		3.86%		14.34%		8.89%
Percent change: Test year vs Most Current Actuals		24.50%											
Average for 2006-2009		7.15%											
Compound Annual Growth Rate (for 2006 to 2009)		1.74%											

b) Please use the same format as shown in Table 1 to provide the OM&A expenses based on CGAAP and exclude Smart Meter related costs.

Response:

There were no smart meter related costs in historical years and 2010, as those were being deferred on the balance sheet in USoA 1556. In 2011, there are Smart Meter related costs in OM&A.

	2006 Board Approved	2006 Actuals	Variance 2006BA - 2006 Actuals	2007 Actuals	Variance 2007 - 2006 Actuals	2008 Actuals	Variance 2008 - 2007 Actuals	2009 Actuals	Variance 2009 - 2008 Actuals	Bridge Year (BY) 2010	Variance BY 2010 - 2009 Actuals	Test Year (TY) 2011	Variance TY - BY
Operation	2,720,134	3,350,836	630,702	3,079,156	(271,680)	3,544,751	465,594	3,815,041	270,290	4,900,708	1,085,667	2,911,549	(1,989,159)
Maintenance	2,700,089	3,023,980	323,891	3,091,210	67,230	3,374,105	282,895	3,159,226	(214,879)	3,590,436	431,210	3,904,606	314,170
Billing and Collecting	3,512,796	3,775,564	262,768	3,820,263	44,699	4,324,468	504,205	4,897,921	573,454	4,632,782	(265,139)	5,656,663	1,023,881
Community Relations	256,376	1,018,450	762,075	797,999	(220,451)	371,587	(426,412)	363,138	(8,449)	570,000	206,862	640,000	70,000
Administrative and General	4,463,821	4,986,820	522,999	5,137,182	150,361	5,558,770	421,588	5,601,103	42,334	6,699,374	1,098,271	7,445,278	745,904
Total OM&A Expenses	13,653,216	16,155,651		15,925,811		17,173,680		17,836,429		20,393,300		20,558,096	
Variance from previous year			2,502,435		(229,840)		1,247,870		662,748		2,556,871		164,796
Percent change (year over year)			18.33%		-1.42%		7.84%		3.86%		14.34%		0.81%
Percent change: Test year vs Most Current Actuals		15.26%											
Average for 2006-2009		7.15%											
Compound Annual Growth Rate (for 2006 to 2009)		1.74%											

Historical GDP values are taken from Statistics Canada. Quarterly values are used to reflect the impact of shifts in the GDP throughout the year. For the Bridge and Test Years the forecast GDP growth for 2010 and 2011 is used as published by the Ministry of Finance.

HEATING DEGREE DAYS AND COOLING DEGREE DAYS

Heating Degree Days and Cooling Degree Days are used to run the regression to determine the predicted kWh. In order to forecast for the Bridge and Test Years the 30 year average is calculated for both heating degree days and cooling degree days. This average is applied to the Bridge and Test Year to forecast the weather normalized kWh's purchased.

CONSERVATION AND DEMAND MANAGEMENT

Hydro One Brampton supports the Ontario Government's conservation and demand management (CDM) initiative and will work with the OPA to meet the new provincial CDM target. The CDM impact assumed for 2011 (64 GWh) was based on Hydro One Brampton's share (2.75%) of the provincial CDM impact assumed for 2011 (2,386 GWh) adjusted for transmission losses (2.5%). The annual CDM impact for 2010-2012 submitted in the IPSP by the OPA to the Ontario Energy Board in August 2007 was adjusted to account for the recent economic recession and its impact on industrial customers and the new CDM target for LDCs for the 2011-2014 period. **Table 1** summarizes the adjusted annual provincial CDM impact assumed by Hydro One Brampton for 2008-2012.

Table 1: Provincial CDM Impact (in GWh)

Provincial CDM Impact (in GWh)

	Provincial CDM Impact Assumed in 2007 IPSP		Provincial CDM Impact Assumed in this Rate Case	
	Incremental	Cumulative since 2008	Incremental	Cumulative since 2008
2008	814	814	814	814
2009	1,146	1,960	1,146	1,960
2010	4,908	6,868	3,416	5,376
2011	1,885	8,753	2,386	7,762
2012	1,909	10,662	2,900	10,662

Note 1: CDM impact is presented at generation station level, weather normal

Note 2: Cumulative CDM impact of 10,662 GWh remains the same by 2012

The CDM impact of 64 GWh assumed for Hydro One Brampton in 2011 is derived as follows:

- 2,386 GWh * (1 – 2.5%) * 2.75% where
- 2,386 GWh is the annual provincial CDM impact for 2011.
- (1 – 2.5%) brings the CDM impact from generation station to wholesale purchase level. Transmission losses are assumed to be 2.5%.
- 2.75% is Hydro One Brampton’s share of the provincial energy estimated by the IESO.

Ontario Energy Board | Commission de l'énergie de l'Ontario

EB-2010-0215
EB-2010-0216

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

AND IN THE MATTER OF a Minister's Directive issued by the Minister of Energy and Infrastructure, to the Ontario Energy Board, pursuant to sections 27.1 and 27.2 of the *Ontario Energy Board Act, 1998* and approved by the Lieutenant Governor in Council on March 31, 2010 as Order in Council No. 437/2010;

AND IN THE MATTER OF a proceeding under section 74 of the *Ontario Energy Board Act, 1998* amending all electricity distributor licences.

BEFORE: Cynthia Chaplin
Vice-Chair and Presiding Member

DECISION AND ORDER

Background

Section 27.1 of the *Ontario Energy Board Act, 1998* (the "Act") states that the Minister of Energy and Infrastructure (the "Minister") "may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directives to promote energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources".

Section 27.2(1) of the Act states that the “Minister may issue, and the Board shall implement, directives that have been approved by the Lieutenant Governor in Council that require the Board to take steps specified in the directive to establish conservation and demand management targets to be met by distributors and other licensees”.

Section 27.2(2) provides: “To promote conservation and demand management, a directive may require the Board to specify, as a condition of a licence, the conservation targets associated with those specified in the directive, and the targets shall be apportioned by the Board between distributors and other licensees in accordance with the directive.”

Section 27.2(7) states: “A directive may specify whether the Board is to hold a hearing, the circumstances under which a hearing may or may not be held and, of a hearing is to be held, the type of hearing to be held.”

The Directive

On March 31, 2010, the Minister issued a Minister’s Directive to the Ontario Energy Board (the “Board”), pursuant to sections 27.1 and 27.2 of the Act. The Directive was approved by the Lieutenant Governor in Council as O.C. 437/2010. The Directive directs the Board to amend the licences of all licensed electricity distributors.

The Directive states, in part:

1. Subject to paragraph 5, the Board shall, without a hearing and in accordance with the requirements of this Directive … amend each distributor’s licence to add a condition requiring the distributor to achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs (“CDM Programs”) by the amounts specified by the Board (the “CDM Targets”), over a four-year period beginning January 1, 2011.

2. In establishing the CDM Targets for each distributor, the Board shall:

   (a) ensure that the total of the CDM Targets established for all distributors is equal to 1330 megawatts (MW) of provincial peak demand persisting at the end of the four-year period and

6000 gigawatt hours (GWh) of reduced electricity consumption accumulated over the four-year period;

(b) specify for each distributor, a CDM Target for the reduction of provincial peak electricity demand and a CDM Target for the reduction of electricity consumption, each of which must be greater than zero; and,

(c) have regard to information obtained from the Ontario Power Authority ("OPA"), developed in consultation with distributors, regarding the reductions in provincial peak electricity demand and electricity consumption that could be achieved by individual distributors through the delivery of CDM Programs.

3. The Board shall amend the licence of each distributor as follows:

(a) by adding a condition that specifies each distributor must meet its CDM Targets through:

(i) the delivery of Board approved CDM Programs delivered in the distributor's service area ("Board-Approved CDM Programs");

(ii) the delivery of CDM Programs that are made available by the OPA to distributors in the distributor's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or,

(iii) a combination of (i) and (ii)

(b) Each licensed electricity distributor must deliver a mix of CDM Programs to all consumer types in the distributor's service area, whether through the Board-Approved CDM Programs, OPA-Contracted Province-Wide CDM Programs or a combination of the two, as far as is appropriate and reasonable having regard to the composition of the distributor's consumer base.

(c) Each licensed electricity distributor must comply with the rules mandated by the Conservation and Demand Management Code for Electricity Distributors, issued on September 16, 2010.

(d) Each licensed electricity distributor must utilize the same common Provincial brand with all:

(i) Board-Approved CDM Programs;
(ii) OPA-Contracted Province-Wide Programs, once those programs have been created; and
(iii) In conjunction with or co-branded with a distributor's own brand or marks.

Licence Amendments

On June 21, 2010, the Board received information from the OPA, developed in consultation with distributors, regarding appropriate reductions (i.e. targets) to peak electricity demand and electricity consumption that could be obtained by individual distributors through the delivery of CDM programs. The Board circulated these proposed targets to distributors for comment on June 22, 2010. The Board considered the comments it received, and has made certain minor adjustments to the CDM Targets as described in a letter dated November 11, 2010.

In order to comply with the Directive, the Board is amending each distributor's licence. As specified in both Directive, and permitted by section 27.2(7) of the Act, these amendments are being made without a hearing. Amended licences will be issued to distributors forthwith.

THE BOARD THEREFORE ORDERS THAT:

1. Each licensed electricity distributor must, as a condition of its licence, meet its respective CDM Targets as established in Appendix A and attached to this Decision.

2. Each licensed electricity distributor must, as a condition of its licence, deliver Board-Approved CDM Programs, OPA-Contracted Province-Wide CDM Programs, or a combination of the two.
3. Each licensed electricity distributor must, as a condition of its licence, comply with the Conservation and Demand Management Code for Electricity Distributors.
4. Each licensed electricity distributor must, as a condition of its licence, utilize the common Provincial brand, once made available by the Ministry, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with a distributor's own brand or marks.

DATED at Toronto, November 12, 2010

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

LDC CDM Targets

#	License Name	2014 Net Annual Peak Demand Savings Target (MW)	2011-2014 Net Cumulative Energy Savings Target (GWh)
1	Algoma Power Inc.	1.280	7.370
2	Atikokan Hydro Inc.	0.200	1.160
3	Attawapiskat Power Corporation	0.070	0.290
4	Bluewater Power Distribution Corporation	10.650	53.730
5	Brant County Power Inc.	3.300	9.850
6	Brantford Power Inc.	11.380	48.920
7	Burlington Hydro Inc.	21.950	82.370
8	COLLUS Power Corporation	3.140	14.970
9	Cambridge and North Dumfries Hydro Inc.	17.680	73.660
10	Canadian Niagara Power Inc.	4.070	15.810
11	Centre Wellington Hydro Ltd.	1.640	7.810
12	Chapleau Public Utilities Corporation	0.170	1.210
13	Chatham-Kent Hydro Inc.	9.670	37.280
14	Clinton Power Corporation	0.320	1.380
15	Cooperative Hydro Embrun Inc.	0.340	1.120
16	E.L.K. Energy Inc.	2.690	8.250
17	ENWIN Utilities Ltd.	26.810	117.890
18	Enersource Hydro Mississauga Inc.	92.980	417.220
19	Erie Thames Powerlines Corporation	4.280	18.600
20	Espanola Regional Hydro Distribution Corporation	0.520	2.760
21	Essex Powerlines Corporation	7.190	21.540
22	Festival Hydro Inc.	6.230	29.250
23	Fort Albany Power Corporation	0.050	0.240
24	Fort Frances Power Corporation	0.610	3.640
25	Greater Sudbury Hydro Inc.	8.220	43.710
26	Grimsby Power Inc.	2.060	7.760
27	Guelph Hydro Electric Systems Inc.	16.710	79.530
28	Haldimand County Hydro Inc.	2.850	13.300
29	Halton Hills Hydro Inc.	6.150	22.480
30	Hearst Power Distribution Company Limited	0.680	3.910
31	Horizon Utilities Corporation	60.360	281.420
32	Hydro 2000 Inc.	0.190	1.040
33	Hydro Hawkesbury Inc.	1.820	9.280
34	Hydro One Brampton Networks Inc.	45.610	189.540
35	Hydro One Networks Inc.	213.660	1,130.210
36	Hydro Ottawa Limited	85.260	374.730
37	Innisfil Hydro Distribution Systems Limited	2.500	9.200
38	Kashechewan Power Corporation	0.070	0.330
39	Kenora Hydro Electric Corporation Ltd.	0.860	5.220

#	License Name	2014 Net Annual Peak Demand Savings Target (MW)	2011-2014 Net Cumulative Energy Savings Target (GWh)
40	Kingston Hydro Corporation	6.630	37.160
41	Kitchener-Wilmot Hydro Inc.	21.560	90.290
42	Lakefront Utilities Inc.	2.770	13.590
43	Lakeland Power Distribution Ltd.	2.320	10.180
44	London Hydro Inc.	41.440	156.640
45	Middlesex Power Distribution Corporation	2.450	9.250
46	Midland Power Utility Corporation	2.390	10.820
47	Milton Hydro Distribution Inc.	8.050	33.500
48	Newmarket - Tay Power Distribution Ltd.	8.760	33.050
49	Niagara Peninsula Energy Inc.	15.490	58.040
50	Niagara-on-the-Lake Hydro Inc.	2.420	8.270
51	Norfolk Power Distribution Inc.	4.250	15.680
52	North Bay Hydro Distribution Limited	5.050	26.100
53	Northern Ontario Wires Inc.	1.060	5.880
54	Oakville Hydro Electricity Distribution Inc.	20.700	74.060
55	Orangeville Hydro Limited	2.780	11.820
56	Orillia Power Distribution Corporation	3.070	15.050
57	Oshawa PUC Networks Inc.	12.520	52.240
58	Ottawa River Power Corporation	1.610	8.970
59	PUC Distribution Inc.	5.580	30.830
60	Parry Sound Power Corporation	0.740	4.160
61	Peterborough Distribution Incorporated	8.720	38.450
62	Port Colborne Hydro Inc.	2.330	9.270
63	PowerStream Inc.	95.570	407.340
64	Renfrew Hydro Inc.	1.050	4.860
65	Rideau St. Lawrence Distribution Inc.	1.220	5.100
66	Sioux Lookout Hydro Inc.	0.510	3.320
67	St. Thomas Energy Inc.	3.940	14.920
68	Thunder Bay Hydro Electricity Distribution Inc.	8.480	47.380
69	Tillsonburg Hydro Inc.	2.290	10.250
70	Toronto Hydro-Electric System Limited	286.270	1,303.990
71	Veridian Connections Inc.	29.050	115.740
72	Wasaga Distribution Inc.	1.340	4.010
73	Waterloo North Hydro Inc.	15.790	66.490
74	Welland Hydro-Electric System Corp.	5.560	20.600
75	Wellington North Power Inc.	0.930	4.520
76	West Coast Huron Energy Inc.	0.880	8.280
77	West Perth Power Inc.	0.620	2.990
78	Westario Power Inc.	4.240	20.950
79	Whitby Hydro Electric Corporation	10.900	39.070
80	Woodstock Hydro Services Inc.	4.490	18.880
Total		**1,330.04**	**5,999.970**

Vulnerable Energy Consumers Coalition Interrogatory #63

References: **Exhibit 9, Tab 3, Schedule 1.1, page 5**

Exhibit 11, Tab 1, Schedule 1.0, page 17

a) Provide a Copy of the OEB Worksheets that calculate the 2006-2009 revenue requirement and Disposition rate rider by rate class (Residential, GS<50 kW). Reconcile with Tables 4 and Table 5 and Exhibit 11 Tab 1 Schedule 1.0.

Response:

The OEB (see OEB Question 48) has requested that Hydro One Brampton exclude costs that were previously approved and recalculate the disposition rider accordingly. HOBNI has excluded these costs and recalculated the revenue requirement for 2006 to 2009 as well as the proposed disposition rider. Please see **Appendix AA** for more detail. (Note that the revised calculations impacted the revenue requirement for 2010 to 2014 and the proposed rate adder).

The following tables provide information on revised revenue requirement calculations from 2006 to 2009, the revised proposed disposition rider as well as the revised proposed rate adder.

Summary of Revised Revenue Requirement Calculations from 2006 to 2009

	2006	2007	2008	2009	Total
Return on rate base	-	162,687	533,944	1,047,289	1,743,920
Operating expenses	-	4,728	6,152	324,466	335,345
Depreciation expenses	-	143,404	483,748	969,455	1,596,608
PILs	-	32,721	91,924	185,565	310,210
Revenue Requirement	**-**	**343,540**	**1,115,769**	**2,526,775**	**3,986,083**

Summary of Revised Revenue Requirement Calculations from 2010 to 2014

	2010	2011	2012	2013	2014	Total
Return on rate base	1,457,404	356,563	361,517	323,557	285,596	2,784,636
Operating expenses	876,347	103,522	103,522	103,522	103,522	1,290,435
Depreciation expenses	1,590,498	486,502	486,502	486,502	486,502	3,536,505
PILs	163,788	(28,155)	113,237	111,942	111,235	472,047
Revenue Requirement	**4,088,037**	**918,431**	**1,064,778**	**1,025,523**	**986,855**	**8,083,624**

Final Disposition Rider

Revenue Requirement:		Previously Filed
2006 Rate Year Entitlement	-	5,207
2007 Rate Year Entitlement	343,540	438,975
2008 Rate Year Entitlement	1,115,769	1,271,193
2009 Rate Year Entitlement	2,526,775	2,678,081
	3,986,083	4,393,456
Smart Rate Rider Billed:		
2006 Rate Year Billed May 1/06 - April 30/07	-	(397,304)
2007 Rate Year Billed May 1/07 - April 30/08	(964,337)	(964,337)
2008 Rate Year Billed May 1/08 - April 30/09	(978,674)	(1,273,225)
2009 Rate Year Billed May 1/09 - Dec 31/09	(1,191,228)	(1,191,228)
	(3,134,239)	(3,826,094)
Smart Meter Costs for Recovery	851,845	567,362
Forecasted Number of Customers	132,427	132,427
Number of Months	12	12
Rate Rider	0.54	0.36

Ongoing Funder Rider

Revenue Requirement:		
2010 Rate Year Entitlement	4,088,037	4,233,124
2011 Rate Year Entitlement	918,431	918,431
2012 Rate Year Entitlement	1,064,778	1,064,778
2013 Rate Year Entitlement	1,025,523	1,025,523
2014 Rate Year Entitlement	986,855	986,855
	8,083,624	8,228,712
Smart Rate Rider Billed:		
2010 Rate Year Forecast Jan 1/10 - December 31/10	(1,595,953)	(1,595,953)
Smart Meter Costs for Recovery	6,487,671	6,632,759
Forecasted Number of Customers	133,888	133,888
Number of Months	48	48
Rate Adder	1.01	1.03

b) Provide a cash flow by rate class that shows the amounts collected and the deficit for each class.

Response:
Please refer to last table in the response to Question 63(a) above for detail. The revenue requirement has been revised downward to $3,986,083 and amount collected decreased to $3,134,239. This resulted in a shortfall of $851,845. As stated above, Hydro One Brampton does not segregate smart meter costs by rate class.

c) Compare this to the proposed Disposition rate rider of $0.36/customer/month and the calculations at lines 2-9 of page 5

Response:
The adjustment to the costing information, as requested by the OEB, increased the shortfall and hence the proposed disposition rider. The revised shortfall is $851,845 and the revised proposed disposition rider is $0.54.

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Ontario

BY EMAIL & WEB POSTING

November 17, 2010

All Licensed Electricity Distributors
All Rate-Regulated Natural Gas Distributors
All Licensed Electricity Transmitters
Ontario Power Generation Inc.
Stakeholders and Other Interested Parties Participating in EB-2008-0408

Transition to International Financial Reporting Standards ("IFRS") – Incentive Rate Making ("IRM") Working Group (Board File EB-2008-0408 continued)

The Board described its multi-phase consultation on the transition to IFRS in a letter of December 23, 2008. One of the outputs of the first phase of the consultation was the Board's policy statement contained in *Report of the Board - Transition to IFRS* dated July 28, 2009, EB-2008-0408 ("Board Report"). In that report the Board stated that it would convene a working group at an appropriate time to address the particulars of implementing IFRS in an IRM environment.

This letter is to initiate the working group process and solicit expressions of interest in participating. It will be called the IFRS IRM Working Group and will continue under Board file number EB-2008-0408. It will be led by Board staff and is expected to complete its work by April 30, 2011.

The Working Group expects to deliver recommendations for consideration by the Board on how IFRS should be adopted in an IRM environment including:

- Proposals as to whether Canadian generally accepted accounting principles (C-GAAP) or IFRS should be used to underwrite incentive rates application filings made in various years and under various combinations of circumstances.

- Proposals regarding what could be done with differences that may arise during an IRM period between regulatory accounting under C-GAAP and regulatory accounting under IFRS (referred to in the Board Report as "modified IFRS").

- Proposals regarding any special implications arising from the transition to IFRS in an earnings sharing environment.

The Board expects that such recommendations from the IFRS IRM Working Group would assist the Board in its policy deliberations regarding the matters addressed.

The minutes of Working Group meetings will be posted on the Board's IFRS webpage.

The Board identified parties eligible for cost awards in its Decision on Cost Eligibility dated January 28, 2009 for participants in the initial phase of the EB-2008-0408 consultation. The Board affirms that list as the list of parties with eligibility for cost awards in the new IFRS IRM Working Group.

In addition to representation from the intervenor community, the Board considers it desirable to have participation from the following utility groups that also were represented in the EB-2008-0408 consultation:

- Coalition of Large Distributors
- Cornerstone Hydro Electric Concepts Association
- Electricity Distributors' Association
- Hydro One Networks Inc.
- Rate-regulated natural gas distributors

The Board requests expressions of interest in participation from these groups as well as any others who may wish to participate in the IFRS IRM Working Group. Any party that wishes to participate in this phase of the IFRS transition consultation should file a letter with the Board to that effect. On receipt of expressions of interest the Board will determine the composition of the Working Group.

For ease of reference the list of participants in the initial phase of consultation is provided in Schedule A, attached.

Cost awards will be available to eligible parties in relation to the following eligible activities:

Activity	Total Eligible Hours per Participant
Participation on IFRS IRM Working Group – it is expected that the working group will meet over the period until April 30, 2011 for one day up to 3 or 4 times, with cost awards being available for a maximum of 18 hours for each working group meeting day covering preparation, attendance, and reporting time.	Up to 18 hours for each working group meeting day Up to 3 or 4 meetings
Written comment on staff's initial proposals	TBD
Written comment on staff's revised proposals (if any)	TBD

Those wishing to participate in the IFRS IRM Working Group should inform the Board Secretary of their interest by **December 1, 2010** with a brief description of the reasons for wanting to participate. They must quote file number **EB-2008-0408** in their letter and include their name, postal address, telephone number and, if available, e-mail address and fax number. Two paper copies of each letter must be provided. The Board asks that respondents make every effort to provide an electronic copy of their letter in searchable/unrestricted Adobe Acrobat (PDF) format and to submit all letters through the Board's web portal at www.errr.oeb.gov.on.ca.

If you do not have a user ID, please visit the "e-filing services" webpage on the Board's website at www.oeb.gov.on.ca and fill out a user ID password request. Additionally, those submitting a letter of request for participation are asked to follow the document naming conventions and document submission standards outlined in the document entitled "RESS Document Preparation – A Quick Guide" also found on the "e-filing services" webpage. If the Board's web portal is not available, electronic copies of letters of comment may be submitted by e-mail at BoardSec@oeb.gov.on.ca. Those who do not have internet access should submit the electronic copy of their request letter on a CD.

Letters requesting status as a participant in the IFRS IRM Working Group must be received by the Board by 4:45 p.m. on **December 1, 2010**.

Awards of Costs

The Board will apply the same procedure regarding cost awards as outlined in the Board's letter of December 23, 2008 and in Appendix A to that letter that established the initial phase of consultation on the Transition to IFRS under EB-2008-0408. To reiterate for clarity, when determining the amount of a cost award, the Board will apply the principles set out in section 5 of its *Practice Direction on Cost Awards*. Groups representing the same interests or class of persons are expected to make every effort to communicate and co-ordinate their participation in this process. The Board will consider any lack of co-operation when determining the amount of a cost award. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

The Board will use the process set out in section 12 of its *Practice Direction on Cost Awards* to implement the payment of the cost awards. Therefore, the Board will act as a clearing house for all payments of cost awards in this process.

For more information on this process, please see the Board's *Practice Direction on Cost Awards* and the December 23, 2009 letter. The Practice Direction can be found on the Board's website at www.oeb.gov.on.ca on the "Rules, Codes, Guidelines and Forms" webpage.

Questions regarding the process should be directed to: Bill Cowan, Senior Manager, Special Projects, Applications and Regulatory Audit at (416) 440-7648 or bill.cowan@oeb.gov.on.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attach.

Schedule A

Participants in Initial EB-2008-0408 Consultation
Concerning Transition to IFRS

1. Association of Major Power Consumers in Ontario
2. Brantford Power Inc.
3. The Building Owners and Managers Association of the Greater Toronto Area
4. Burlington Hydro Inc.
5. Cambridge and North Dumfries Hydro Inc.
6. Canadian Manufacturers & Exporters
7. Canadian Niagara Power Inc.
8. Centre Wellington Hydro Ltd.
9. Chatham-Kent Hydro Inc.
10 City of Kitchener
11. Consumers Council of Canada
12. Cornerstone Hydro Electric Concepts Association Inc.
13. Deloitte Canada
14. The Electricity Distributors Association
15. Enbridge Gas Distribution Inc.
16. Energy Probe Research Foundation
17. Enersource Hydro Mississauga Inc.
18. Enwin Utilities Ltd.
19. Erie Thames Powerlines
20. Ernst & Young LLP
21. Festival Hydro Inc.
22. Great Lakes Power Ltd.
23. Greater Sudbury Hydro Inc.
24. Guelph Hydro Electric Systems Inc.
25. Halton Hills Hydro Inc.
26. Horizon Utilities Corporation
27. Hydro One Brampton Networks Inc.
28. Hydro One Networks Inc.

29. Hydro Ottawa Limited
30. Independent Electricity System Operator
31. Industrial Gas Users Association
32. Innisfil Hydro Distribution Systems Ltd.
33. Kingston Hydro Corporation
34. Kitchener Wilmot Hydro Inc.
35. Lakefront Utilities Inc.
36. Lakeland Power Distribution Ltd.
37. London Property Management Association
38. Merritt & Associates
39. Newmarket-Tay Power Distribution Ltd.
40. Norfolk Power Distribution Inc.
41. North Bay Hydro Distribution Ltd.
42. Five Nations Associates Energy Inc. and Natural Resource Gas Ltd.
43. Ontario Power Authority
44. Ontario Power Generation Inc.
45. Orangeville Hydro Limited
46. Orillia Power Distribution Corporation
47. PowerStream Inc.
48. Power Workers' Union
49. School Energy Coalition
50. Toronto Hydro Electric System Ltd.
51. Union Gas Limited
52. Veridian Connections Inc.
53. Vulnerable Energy Consumers Coalition
54. Waterloo North Hydro Inc.
55. Welland Hydro-Electric System Corporation
56. Whitby Hydro Electric Corporation

Ontario Energy Board Interrogatory # 10

Ref: Exhibit 2/ Tab 5/ Schedule 1.0 – Capital Expenditures

On page 2, Table 1 provides capital expenditures for the period from 2006 to 2011 based on IFRS.

a) Please use the same format as Table 1 to provide the expenditures based on CGAAP.

Response:

Exhibit 2, Tab 5, Schedule 1, Table 1 based on CGAAP is shown below:

OEB #	Description	2006	2007	2008	2009	2010	2011
1805	Land	-	-	-	-	-	-
1806	Land Rights	58,458	19,170	7,069	23,226	349,700	208,600
1808	Buildings and Fixtures	1,123,351	1,630,659	1,283,556	602,472	4,663,780	925,523
1815	Transformer Station Equipment - Normally Primary above 50 kV	3,474	12,600	3,803,296	257,953	(3,568,526)	1,666,324
1820	Distribution Station Equipment - Normally Primary below 50 kV	639,781	192,033	169,870	279,295	1,116,601	971,404
1830	Poles, Towers and Fixtures	5,802,455	5,777,486	4,388,180	7,129,091	6,712,536	5,703,841
1835	Overhead Conductors and Devices	2,191,510	1,983,311	2,073,555	2,214,142	1,790,835	1,067,069
1840	Underground Conduit	2,284,568	2,102,665	1,926,785	4,665,139	3,098,681	3,647,050
1845	Underground Conductors and Devices	6,352,682	23,445,365	16,144,870	7,731,744	10,178,876	13,701,644
1850	Line Transformers	3,160,025	2,278,674	5,378,129	6,208,233	4,376,562	6,252,444
1855	Services	714,723	793,538	544,543	613,536	661,552	767,000
1860	Meters	1,170,387	6,157,185	6,392,693	9,445,080	1,026,415	991,000
1908	Buildings and Fixtures	-	-	-	-	(0)	-
1915	Office Furniture and Equipment	47,337	86,526	84,367	2,570	528,000	168,475
1920	Computer Equipment - Hardware	453,294	476,458	155,453	70,653	840,400	305,200
1925	Computer Software	226,383	508,907	184,032	-	-	-
1930	Transportation Equipment	714,607	1,355,127	90,483	215,003	1,979,999	2,294,478
1935	Stores Equipment	19,150	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	152,979	287,536	156,761	159,036	381,000	104,962
1950	Power Operated Equipment	-	-	-	-	-	-
1955	Communication Equipment	50,146	102,028	78,757	117,318	41,600	133,400
1960	Miscellaneous Equipment	16,025	15,620	12,711	8,554	-	-
1980	System Supervisory Equipment	195,795	208,555	144,806	64,979	101,000	501,000
1995	Contributions and Grants - Credit	(4,471,257)	(18,528,211)	(16,082,800)	(12,704,438)	(11,658,493)	(14,587,030)
2055	Construction Work in Progress--Electric	682,425	1,964,208	(1,397,746)	798,274	3,216,066	(1,261,441)
2040	Electric Plant Held for Future Use	-	-	3,554,454	258,332	-	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	5,118,257	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	84,843	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	(130,042)	5,268,063	-
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	61,000	961,600	554,800
	Total	**21,588,299**	**30,869,441**	**29,093,824**	**33,294,250**	**32,066,248**	**24,115,743**

b) Please use the same format as Table 1 to provide the expenditures based on CGAAP and exclude Smart Meter related costs.

Response:

Exhibit 2, Tab 5, Schedule 1, Table 1 based on CGAAP excluding Smart Meter costs is shown below:

OEB #	Description	2006	2007	2008	2009	2010	2011
1805	Land	-	-	-	-	-	-
1806	Land Rights	58,458	19,170	7,069	23,226	349,700	208,600
1808	Buildings and Fixtures	1,123,351	1,630,659	1,283,556	602,472	4,663,780	925,523
1815	Transformer Station Equipment - Normally Primary above 50 kV	3,474	12,600	3,803,296	257,953	(3,568,526)	1,666,324
1820	Distribution Station Equipment - Normally Primary below 50 kV	639,781	192,033	169,870	279,295	1,116,601	971,404
1830	Poles, Towers and Fixtures	5,802,455	5,777,486	4,388,180	7,129,091	6,712,536	5,703,841
1835	Overhead Conductors and Devices	2,191,510	1,983,311	2,073,555	2,214,142	1,790,835	1,067,069
1840	Underground Conduit	2,284,568	2,102,665	1,926,785	4,665,139	3,098,681	3,647,050
1845	Underground Conductors and Devices	6,352,682	23,445,365	16,144,870	7,731,744	10,178,876	13,701,644
1850	Line Transformers	3,160,025	2,278,674	5,378,129	6,208,233	4,376,562	6,252,444
1855	Services	714,723	793,538	544,543	613,536	661,552	767,000
1860	Meters	1,105,012	910,865	484,492	782,066	1,026,415	991,000
1908	Buildings and Fixtures	-	-	-	-	(0)	-
1915	Office Furniture and Equipment	47,337	86,526	84,367	2,570	528,000	168,475
1920	Computer Equipment - Hardware	453,294	476,458	155,453	70,653	840,400	305,200
1925	Computer Software	226,383	508,907	184,032	-	-	-
1930	Transportation Equipment	714,607	1,355,127	90,483	215,003	1,979,999	2,294,478
1935	Stores Equipment	19,150	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	152,979	287,536	156,761	159,036	381,000	104,962
1950	Power Operated Equipment	-	-	-	-	-	-
1955	Communication Equipment	50,146	102,028	78,757	117,318	41,600	133,400
1960	Miscellaneous Equipment	16,025	15,620	12,711	8,554	-	-
1980	System Supervisory Equipment	195,795	208,555	144,806	64,979	101,000	501,000
1995	Contributions and Grants - Credit	(4,471,257)	(18,528,211)	(16,082,800)	(12,704,438)	(11,658,493)	(14,587,030)
2055	Construction Work in Progress--Electric	682,425	1,964,208	(1,397,746)	798,274	3,216,066	(1,261,441)
2040	Electric Plant Held for Future Use	-	-	3,554,454	258,332	-	-
1610	Miscellaneous Intangible Plant - TS CIP	-	-	-	5,118,257	-	-
1610	Miscellaneous Intangible Plant - Software CIP	-	-	-	84,843	-	-
1610	Miscellaneous Intangible Plant - TS in-service	-	-	-	(130,042)	5,268,063	-
1610	Miscellaneous Intangible Plant - Software in-service	-	-	-	61,000	961,600	554,800
	Total	**21,522,924**	**25,623,120**	**23,185,623**	**24,631,236**	**32,066,248**	**24,115,743**

c) In the bottom of Table 1, there is a note stating: “Above Capital Expenditures exclude $300,000 of borrowing costs which are included in the total in Exhibit 2, Tab 6, Schedule 9.” Please explain what type of borrowing costs this statement is referring to.

Response:

The note at the bottom of Table 1 should have read as follows: “Above Capital Expenditures include $300,000 of borrowing costs.” The reference to Exhibit 2, Tab 6, Schedule 9 should not have been made

RATE BASE OVERVIEW

The rate base used for the purpose of calculating the revenue requirement used in this Application was calculated based on guidelines set out in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, issued on May 27, 2009. Based on these requirements, the rate base for the 2011 Test Year was calculated as the difference between the average of the opening and closing gross fixed assets and accumulated depreciation plus a working capital allowance amounting to 15% of working capital. Working capital is equal to the sum of the cost of power and controllable expenses.

The net fixed assets include distribution assets as well as smart meter capital costs as at the end of 2009. All non-distribution assets were excluded. Controllable expenses include operations and maintenance, billing and collecting, community relations, and administration and general expenses.

Hydro One Brampton has provided its rate base calculations for the years 2006 Board Approved through 2011 Test Year in **Table 1**, below. The estimated rate base for the 2011 Test Year is $335,073,828. This amount is approximately 34.44% higher than the 2006 Board Approved rate base, reflecting an average annual increase of 6.89%.

Table 1: Rate Base Calculations Summary

Description	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Bridge	2011 Test
Opening Balance Gross Fixed Assets	351,758,493	384,136,113	404,647,864	433,205,354	462,676,170	257,908,905	288,315,028
Closing Balance Gross Fixed Assets	368,501,151	404,647,864	433,205,354	462,676,170	490,620,682	288,315,028	310,560,951
Average Gross Fixed Assets	360,129,822	394,391,988	418,926,609	447,940,762	476,648,426	273,111,966	299,437,990
Opening Balance Accumulated Depreciation	143,041,521	169,258,534	183,765,121	199,241,008	215,299,494	-	12,206,510
Closing Balance Accumulated Depreciation	155,544,566	183,765,121	199,241,008	215,299,494	232,711,777	12,206,510	24,637,484
Average Accumulated Depreciation	149,293,043	176,511,827	191,503,065	207,270,251	224,005,636	6,103,255	18,421,997
Opening Net Book Value	208,716,972	214,877,579	220,882,743	233,964,346	247,376,676	257,908,905	276,108,517
Closing Net Book Value	212,956,585	220,882,743	233,964,346	247,376,676	257,908,905	276,108,517	285,923,468
Average Net Book Value	210,836,778	217,880,161	227,423,544	240,670,511	252,642,790	267,008,711	281,015,992
Working Capital	256,007,904	283,451,085	291,888,329	293,021,651	303,349,708	359,651,644	360,385,567
Working Capital Allowance -15%	38,401,186	42,517,663	43,783,249	43,953,248	45,502,456	53,947,747	54,057,835
Rate Base	249,237,964	260,397,824	271,206,794	284,623,759	298,145,246	320,956,457	335,073,828

The replacement of a 2002 pick-up truck (V53) with high mileage with a new pick-up truck is scheduled for this year. The consideration of a hybrid vehicle is being evaluated.

MAJOR TOOLS & EQUIPMENT IFRS $103,000

This category is used for the purchase of tools and equipment by all departments, where the cost of such exceeds $1,000.00$500.00. Such purchases involve replacing aged or defective tools no longer suitable for service as well as the purchase of new tools providing improved safety, ergonomics and technology.

GREEN ENERGY IFRS $864,349

HOBNI has identified six projects under the green energy category. These projects will introduce automated switching and reclosure technology into the HOBNI distribution system. Highlights of this program include the coordinated installation of 6 - motorized 44 kV load interrupter switches; 1 - “Scadamate” load interrupter switch; 2 - G&W 3Ph 3-Way Solid Dielectric Dead Front Submersible Vacuum Switches; and 6- “Trip Saver” reclosures. These devices are being introduces at key locations in our grid to improve outage response and recovery time.

ADMIN. & SERVICE CENTRE IFRS $532,643

In 2009 the Day Care tenant moved out of the Sandalwood Administrative facilities. Therefore, the Company now has approximately 4,500 sq ft that is not being used. The budget of $304,643 is to cover all costs to rework this space to the Company’s needs. Note: Hydro One Brampton is seeking new tenants for this space and therefore this rework will hinge on when/if the new tenant is found. This is due to the fact HOBNI will need to configure the space to their needs.

Also in 2010 HOBNI have $60,000 to reconfigure the old day-care parking area and remove the existing playground areas.

Lastly HOBNI has $168,000 for various projects related to Facility and Office equipment improvements/replacements.

ADMINISTRATIVE COMPUTER AS/400 IFRS $1,265,000

Hardware/Software Network Consolidation

Hydro One Brampton Networks Inc. will undertake to consolidate and standardize their Information Technology Infrastructure. This hardware/software will allow HOBNI to improve server utilization and data storage for all HOBNI programs and data. This will also provide the

Energy Probe Interrogatory # 14

Ref: Exhibit 2, Tab 5, Schedule 7.0, page 8

a) Please clarify what HOBNI means by the rework associated with the 4,500 sq ft that is not being utilized "will hinge on when/if the new tenant is found". Does HOBNI mean that it will not spend the $304,643 included in the 2010 capital budget if a tenant is not found?

Reponse:

This space requires substantial rework and therefore we would not spend monies until a tenant was secured or alternately we needed this space ourselves.

b) Please provide an update on the status of the search for a new tenant.

Reponse:

Still no tenant found.

c) Will HOBNI proceed with the $60,000 expenditure to reconfigure the old day-care parking area and remove the existing playground areas in 2010 if no replacement tenant is found? If yes, please explain why.

Response:

No

d) What was the annual revenue received for the rental of this space?

Response:

The annual revenue received for the rental of this space was as follows:

Year	Daycare rental revenue	
2009	$	33,963
2008	$	42,750
2007	$	42,375
2006	$	41,344

Ontario Energy Board Interrogatory # 36

Ref: Exhibit 5 / Tab 1/ Schedule 2.0 Long-term Debt

On page 2, it states: "At the end of 2009 HOBNI had $143 million of long-term debt with Hydro One Inc. at an annual interest rate of 6.95%. HOBNI proposes to add $10 million of new long-term debt with Hydro One Inc. in 2010, and another $47 million in 2011. This new debt has an assumed 30 year term at an annual interest rate of 5.71% and 6.41% respectively."

a) Please advise whether the 2010 new debt has been executed. If so, what is the actual debt rate? Please provide the terms of the agreement.

Response:

No new debt has been issued by the parent for 2010.

b) When is the new debt for 2011 expected to be issued?

Response:

Hydro One Brampton's debt financing strategy takes into consideration the objectives of cost effectiveness, distributing debt maturities evenly over time, and ensuring the term of the debt portfolio is compatible with the long life of the Company's assets. As such, for planning purposes, debt is forecast to be issued mid-year.

c) Please provide the updated interest rate assumption for the new 2011 debt instrument and explain how the rate was determined

Response:

Hydro One Brampton does not plan to update the forecast 2011 debt costs.

School Energy Coalition Interrogatory # 33

[Ex. 5/1/2.0]

With respect to Cost of Capital

a. P. 1. Please explain why the Applicant's ROE and short-term debt rate would not be set by this Board prior to the effective date of new rates. Please identify the latest Consensus Forecast and Government of Canada/A rated Canadian Utility index bond yields that could be used to set rates in a timely manner for January 1, 2011.

Response:

HOBNI's ROE and short-term debt rate could be set by this Board prior to the effective date of new rates on January 1, 2011 based on the September 2010 market interest rate information.

b. P. 2. Please provide the debenture documents relating to the public debenture issue referred to, including but not limited to all documents relating to the rights to redeem or repurchase prior to maturity. Please confirm that this issue included borrowing for the Applicant and for other purposes by the parent company. Assuming that to be the case, please confirm that any repayment or refinancing of the debenture have been applied pro rata to the respective uses to which it was originally put.

Response:

See **Appendix AN**

The issue referred to was for $300M of which $143M was allocated to HOBNI, the remainder was for HOI purposes. There has been no repayment or refinancing of the HOBNI debt.

c. P. 2. Please provide an update of the basis of the 6.41% forecast of 30 year debt in 2011 (e.g. a more recent version of the Consensus Forecasts). Please provide details of the timing of the expected borrowing. Please provide the current market price of such debt.

An update of the basis of the 6.41% forecast of 30 year debt and timing is provided in response in Exhibit 12, Tab 1, Schedule 36 parts (b) and (c). The current market yield for long term debt is approximately 5.0%.

Update of forecast for 30 year debt	Bridge	Test	
	2010	**2011**	**2012**
5-Year			
Government of Canada %	2.64	3.14	3.84
Hydro One Credit Spread %	0.86	0.86	0.86
Hydro One Bond Interest Rate %	3.50	4.00	4.70
10-Year			
Government of Canada %	3.40	3.90	4.60
Hydro One Credit Spread %	1.19	1.19	1.19
Hydro One Bond Interest Rate %	4.59	5.09	5.79
30-Year			
Government of Canada %	3.95	4.45	5.15
Hydro One Credit Spread %	1.49	1.49	1.49
Hydro One Bond Interest Rate %	5.44	5.94	6.64
90-Day BA Rate %	0.32	2.16	3.45

d. Please describe all steps that the Applicant has taken, if any, to determine whether it can redeem or repay the $143 million note in whole or in part. Please describe all barriers to that potential refinancing. Please provide all internal documents in the period from 2008 to date relating to repaying or refinancing that debt, and all calculations of potential future interest cost savings done by the Applicant.

Response:

There has been no repayment or refinancing of the HOBNI debt. The Note with HOI is callable by HOBNI; however, the call price is determined based upon the Government of Canada yield (for a maturity of the same term) plus 0.22%. Hydro One's debt issuance spread level is much higher than the 0.22%; hence, it is not economic for HOBNI to call and refinance this debt. To refinance the existing HOBNI debt with 3rd party debt having the same remaining term of approximately 20 years Hydro One Inc would issue new debt based upon the Government of Canada yield for a comparable maturity plus a spread of between 1.19% (10 year spread) and 1.49% (30 year spread), as shown in response to Exhibit 12, Tab 1, Schedule 36 part (c).

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BY E-MAIL AND WEB POSTING

November 15, 2010

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 January 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 January 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. As the Board has received applications requesting January 1, 2011 effective dates for rate changes, the Board has decided to advance 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.

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.

Based on the methodologies set out in the Report and September 2010 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 January 1, 2011 are summarized in the table below. While short-term rates have risen generally in line with changes in the Bank of Canada rate, results for the long-term debt rate and ROE due to changes in bond yields reflect lessened confidence in the pace of the global economic recovery. The Board considers these Cost of Capital parameter values and the relationships between them reasonable and representative of market conditions at this time.

Cost of Capital Parameter	**Value for 2011 Cost of Service Applications for January 1, 2011 rate changes**
ROE	9.66%
Deemed LT Debt rate	5.48%
Deemed ST Debt rate	2.43%

These values will be applied by the Board in its consideration of 2011 electricity cost of service applications for rates effective January 1, 2011. A summary of the calculations of the Cost of Capital parameters is attached.

For rates with effective dates subsequent to January 1, 2011 (e.g. May 1, 2011) during 2011, the Board will use 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, but will update the cost of capital parameters based on data from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP for three months prior to the effective date, per the methodologies documented in the Report.

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@oeb.gov.on.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Attachment: Cost of Capital Parameter Calculations

(assuming January 1, 2011 implementation date for rate changes)

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2010

	Day	Bond Yields (%) Government of Canada 10-yr	Bond Yields (%) Government of Canada 30-yr	Bond Yields (%) A-rated Utility 30-yr	Bond Yield Spreads (%) 30-yr Govt over 10-yr Govt	Bond Yield Spreads (%) 30-yr Util over 30-yr Govt
1	1-Sep-10	2.85	3.50	5.06	0.65	1.56
2	2-Sep-10	2.87	3.52	5.09	0.65	1.57
3	3-Sep-10	2.95	3.57	5.11	0.62	1.54
4	4-Sep-10					
5	5-Sep-10					
6	6-Sep-10					
7	7-Sep-10	2.81	3.47	5.00	0.66	1.53
8	8-Sep-10	2.92	3.53	5.11	0.61	1.58
9	9-Sep-10	2.97	3.56	5.07	0.59	1.51
10	10-Sep-10	2.97	3.55	5.08	0.58	1.53
11	11-Sep-10					
12	12-Sep-10					
13	13-Sep-10	2.95	3.54	5.07	0.59	1.53
14	14-Sep-10	2.94	3.52	5.09	0.58	1.57
15	15-Sep-10	2.96	3.54	5.07	0.58	1.53
16	16-Sep-10	2.97	3.55	5.07	0.58	1.52
17	17-Sep-10	2.93	3.50	5.04	0.57	1.54
18	18-Sep-10					
19	19-Sep-10					
20	20-Sep-10	2.94	3.50	5.05	0.56	1.55
21	21-Sep-10	2.89	3.48	5.03	0.59	1.55
22	22-Sep-10	2.87	3.43	4.96	0.56	1.53
23	23-Sep-10	2.83	3.41	4.95	0.58	1.54
24	24-Sep-10	2.86	3.42	4.95	0.56	1.53
25	25-Sep-10					
26	26-Sep-10					
27	27-Sep-10	2.80	3.38	4.88	0.58	1.50
28	28-Sep-10	2.74	3.33	4.88	0.59	1.55
29	29-Sep-10	2.74	3.33	4.87	0.59	1.54
30	30-Sep-10	2.75	3.35	4.86	0.60	1.51
31						
		2.88	3.48	5.01	**0.594** ❶	**1.539** ❷
	Sources:	*Bank of Canada*		*Bloomberg L.P.*		

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts* Publication Date: September 13, 2010

	3-month	12-month	Average
September 2010	3.100	3.600 ❸	**3.350** %

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	3.350 %
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.594 %
Long Canada Bond Forecast (LCBF)	❹	**3.944** %

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75 %
Change in Long Canada Bond Yield Forecast from September 2009			
LCBF (September 2010) (from Step 3)	④	3.944 %	
Base LCBF		4.250 %	
Difference		-0.306 %	
0.5 X Difference			-0.153 %
Change in A-rated Utility Bond Yield Spread from September 2009			
A-rated Utility Bond Yield Spread (September 2010) (from Step 1)	②	1.539 %	
Base A-rated Utility Bond Yield Spread		1.415 %	
Difference		0.124 %	
0.5 X Difference			0.062 %
Return on Equity based on September 2010 data			**9.66** %

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2010 (from Step 3)	④	3.944 %
A-rated Utility Bond Yield Spread September 2010 (from Step 1)	②	1.539 %
Deemed Long-term Debt Rate based on September 2010 data		**5.48** %

References on Calculation Methods:

- **Return on Equity**: Appendix B of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.
- **Deemed Long-term Debt Rate**: Appendix C of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.

Attachment: Cost of Capital Parameter Calculations

(assuming January 1, 2011 implementation date for rate changes)

Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in January, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	Average Spread over 90-day Bankers Acceptance (basis points)		Date of input
Bank 1	125.0	bps	Sept., 2010
Bank 2	125.0	bps	Sept., 2010
Bank 3	112.5	bps	Sept., 2010
Bank 4	150.0	bps	Sept., 2010
Bank 5	125.0	bps	Sept., 2010
Bank 6			

B. Discard high and low estimates

If less than 4 estimates, take average without discarding high and low.

Number of estimates	5	
High estimate	150.0	bps
Low estimate	112.5	bps

C. Average annual Spread	125.000	bps	❶

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2010

Month:		**September 2010**
		Bankers' Acceptance Rate (%)
	Day	**3-month**
1	1-Sep-10	1.03 %
2	2-Sep-10	1.03 %
3	3-Sep-10	1.08 %
4	4-Sep-10	
5	5-Sep-10	
6	6-Sep-10	
7	7-Sep-10	1.12 %
8	8-Sep-10	1.20 %
9	9-Sep-10	1.20 %
10	10-Sep-10	1.20 %
11	11-Sep-10	
12	12-Sep-10	
13	13-Sep-10	1.20 %
14	14-Sep-10	1.20 %
15	15-Sep-10	1.20 %
16	16-Sep-10	1.20 %
17	17-Sep-10	1.20 %
18	18-Sep-10	
19	19-Sep-10	
20	20-Sep-10	1.20 %
21	21-Sep-10	1.21 %
22	22-Sep-10	1.20 %
23	23-Sep-10	1.20 %
24	24-Sep-10	1.21 %
25	25-Sep-10	
26	26-Sep-10	
27	27-Sep-10	1.21 %
28	28-Sep-10	1.20 %
29	29-Sep-10	1.21 %
30	30-Sep-10	1.21 %
31		
		1.177 % ❷

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Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	1.250	%	①
Average Bankers' Acceptance Rate	1.177	%	②
Deemed Short Term Debt Rate	**2.43**	%	

Reference on Calculation Method:

- Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.

Cost of Debt: Long Term

Hydro One Brampton is requesting a return on Long Term Debt for the 2011 Test Year of 6.76% which is the weighted average long term debt for the 2011 Test Year. **Table 2** below calculates the debt rate:

Table 2: Long Term Debt and Weighted Average Debt Rate for 2011 Test Year

Description	Issue Date	Debenture	Debt Rate	Interest on Debt
Debt through parent company public debenture issue	2001	$ 143,000,000	6.95%	$ 9,938,500
New Debt to be issued through parent in 2010	2010	$ 10,000,000	5.71%	$ 571,000
New Debt to be issued through parent in 2011	2011	$ 47,000,000	6.41%	$ 3,012,700
Totals		**$ 200,000,000**	**6.76%**	**$ 13,522,200**

All debt held by Hydro One Brampton is held by its shareholder Hydro One Inc. through external debt issuances. In the Cost of Capital Report the OEB determined "that for embedded debt the rate approved in prior Board decisions shall be maintained for the life of each active instrument, unless a new rate is negotiated, in which case it will be treated as new debt.

Cost of Debt: Short Term

Hydro One Brampton is requesting a return on Short Term Debt for the 2011 Test Year of 2.07% in accordance with the Cost of Capital Parameter Updates for 2009 Cost of Service Applications issued by the OEB on March 7, 2009. Hydro One Brampton understands that the OEB will be finalizing the return on short term debt for 2011 rates based on January 2011 market interest rate information. Hydro One Brampton's use of a Return on Short Term Debt of 2.07% is without prejudice to any revised ROE that may be adopted by the OEB in early 2010.

NEW LONG-TERM DEBT ASSUMPTIONS

At the end of 2009 HOBNI had $143 million of long-term debt with Hydro One Inc. at an annual interest rate of 6.95%. HOBNI proposes to add $10 million of new long-term debt with Hydro One Inc. in 2010, and another $47 million in 2011. This new debt has an assumed 30 year term at an annual interest rate of 5.71% and 6.41% respectively.