The Coalition of Large Distributors (CLD)

Cost of Capital

A. Policy Objective and Principles

Q1 Please reconcile the 6 Guiding Objectives contained in Board staff's July 25, 2006 Discussion Paper (pages 5 and 6) with the Board's legislated objectives pursuant to section 1 of the *Ontario Energy Board Act, 1998*.

A1 The 6 guiding objectives identified in the 2006 Discussion Paper are consistent with the Board's legislated objectives pursuant to s. 1 of the OEB Act. The 6 guiding objectives all relate to protecting the interests of consumers and/or promoting economic efficiency and cost effectiveness.

Q2 Does Board staff consider further consolidation and rationalization of the Ontario LDC sector to be an implicit Guiding Objective in the Cost of Capital/IRM review? If so, please identify the policy origin for this objective (e.g. direction from the Board/direction from the Government of Ontario).

A2 Further consolidation and rationalization of the Ontario LDC sector was not a guiding objective in the cost of capital and incentive regulation reviews. Rather, as stated on page 6 of the staff Discussion Paper dated July 25, 2006, "the objective is to avoid imposing barriers to consolidation within the electricity distribution sector". The issue of amalgamations was also raised during the Technical Conference (reference Tr. 1 page 55) and the response was that "The objective that we've clearly identified in our paper is to not create any barriers to amalgamation".

Q3 Please compare and contrast the Board staff's interest in promoting consolidation among distributors with the construction of the 2GIRM and the proposals on the rate making treatment of the cost of capital. Please provide an analysis of the consistency of these initiatives in achieving that interest.

A3 Please see response to CLD Q2.

Q4 During the Technical Conference counsel for Board Staff indicated his position that the Board has jurisdiction with respect to establishing distribution rates by Code. Please provide a copy of any legal opinion that the Board or Board Staff has obtained in connection with this matter. If no legal opinion has been sought at this time, will Board staff undertake to obtain a legal opinion in view of the stakeholder concerns expressed during the Technical Conference regarding OEB jurisdiction.

A4 The Board does not undertake activities for which there is no authority in its enabling legislation. In any event, the Board's licence amendment proceeding (EB-2006-0087) is the more appropriate forum for addressing concerns regarding the Board's overall approach to implementing the cost of capital and incentive regulation methodologies.

B. Cost of Capital

Q5 Please provide evidence that the flotation cost for new equity issuances (in Canada) is only 50 basis points.

A5 In its Generic Cost of Capital Decision 2004-0052 (July 2, 2004), the Alberta Energy and Utilities Board determined that "a continuation of a 0.50% [i.e. 50 basis points] allowance for flotation costs and financing flexibility is appropriate." (p.21)

In the "Ontario Energy Board: Draft Guidelines On A Formula-Based Return On Common Equity For Regulated Utilities" (March 1997), it is noted in the Appendix that the British Columbia Utilities Commission similarly allowed 50 b.p. for flotation and dilution costs.

With regard to the 50 basis point cushion, in its Decision and Order RP-2002-0158 on a Review of the Board's Guidelines for Establishing Their Respective Return on Equity (applicable to Union Gas Limited and Enbridge Gas Distribution Inc.), the Board stated in its Findings that "No party has disputed the use of the long-term Government of Canada bond yield as the basis of the risk free rate, or the basis for its forecast as contained in the current ROE guidelines other than the suggestion to fix the spread between the 10 and 30 year bond yields. Also, there was no dispute about the 50 basis points cushion [for financing flexibility]". (para. 136)

Q6 What types of fees does Board staff's 50 basis point floatation cost adder include? For example, does it include syndication fees, legal fees, printing fees, "road show" fees, filing fees, etc.

A6 The 50 basis points may accommodate all of these fees.

Q7 Board staff's Discussion Paper dated July 25, 2006 notes that the current staff proposal has, as one of its guiding objectives, the promotion of economic efficiency by providing the appropriate pricing signals and a system of incentives for distributors to maintain an appropriate level of reliability and service quality (p. 5). Please explain how a lower return on equity and a price cap formula provides such incentives for distributors.

A7 Economic efficiency may be served either by delivering the same benefit with fewer resources, an increased benefit with the same resources or increased benefits with the value of incremental resources less than the incremental benefit. Price caps and lower ROE are both consistent with all three possibilities, depending on the changes in load, price and quality of service, cost structures and movements in the market cost of capital.

Q8 Please indicate whether Board staff has carried out an analysis of the impact on Interest Coverage Ratios for LDCs with outstanding third-party debt from moving to a lower return on equity. If such an analysis has been carried out, please provide the results.

A8 No, this analysis has not been done.

Q9 Board staff's Discussion Paper dated July 25, 2006 notes that staff has reviewed regulatory practice in several key Canadian and United Sates jurisdictions (p. 9). Please provide a summary table of all the jurisdictions examined, the findings from these regulatory jurisdictions, and clearly identify whether these jurisdictions dealt with electricity distribution companies.

A9 In addition to jurisdictions discussed in Lazar and Prisman's paper, staff considered Alberta, British Columbia, Newfoundland, Prince Edward Island, California, Idaho, Illinois, New York, Washington, and Wisconsin.

Q10 Board staff's Discussion Paper dated July 25, 2006 notes that one set of unusual challenges faced by the Ontario electricity distribution sector is the transition from one regulatory regime to another and the associated political uncertainty (p. 10). Board staff goes on to say that this risk is addressed in its proposal (p.11). Please explain how Board staff has incorporated this risk into its return on equity calculation.

A10 Explicit weighting of these specific risks was not done.

Q11 Board staff's Discussion Paper dated July 25, 2006 notes that the appropriate risk-less rate for regulated utilities is a smoothed average of zero coupon curves (p. 12). Please provide support for why Board staff feels that (effectively) a ten-year average interest rate (as used by Lazar and Prisman) is an appropriate risk-less rate for signaling the return to long-lived (30-year plus) distribution assets. Additionally, from the discussion between McShane and Lazar, it appears that the selection of 5, 10 and 15-year maturities was quite arbitrary and was not based on the term structure of the utility assets being financed. A 30-year maturity could be extrapolated from their modeling apparently. If so why has the 30-year not been used as the long-term risk free rate?

A11 Staff adopted the recommendations made by Lazar and Prisman. The methodology recommended by Lazar and Prisman does reflect the 30 year coupon data. A curve is fitted to the Bank of Canada yield curves, which include all of the inferred zero coupon rates and the average of the 5, 10 and 15 years rate from the fitted curve are taken as the appropriate average for the purpose of establishing the riskless rate.

Lazar and Prisman add that this rate is to be used in order to determine the ROE over the "next period". Indeed their estimation is affected by the 30 year zero coupon.

Q12 Board staff's July 25, 2006 Discussion Paper states that staff has derived the risk-less rate by focusing on the shortest and longest terms available (1 year and 15 years) for zero coupon bond data. Lazar and Prisman indicated at the Technical Conference that their data was sourced from the Bank of Canada. A careful examination of this data source shows that the Bank of Canada also publishes 20-year and 30-year zero coupon rates. Please explain why Board Staff has chosen <u>not</u> to use 30-year zero coupon data.

A12 Please see response to CLD Q11. A discussion of this matter is captured on pages 68 through 72 of the September 18, 2006 technical conference transcript.

Q13 If Board staff recommends the implementation of a return on equity structure that provides a premium return for new infrastructure investment, please explain how Board staff envisions the mechanics of this structure. Will the higher equity return be used as the basis for a higher, blended ROE, for the LDCs overall rate base? Will the higher ROE only apply to the new capital portion of the rate base? If so, has Board staff considered the impact of such a structure on LDCs' accounting systems, financial statements, and financial ratios?

A13 This premium was presented to promote discussion. Detailed analysis on a premium return for new infrastructure investment has not been done.

Distributors that have concerns about the impact of the return on equity structure on their accounting systems, financial statements and financial ratios can make those concerns known to the Board through this process.

Q14 Board staff has indicated a preference for setting the deemed cost of new affiliated debt at the risk-less rate plus a bond market spread based on difference between the average rate of a suitable sample of corporate A/BBB bonds and the average rate for Canada bonds of the same term structure (Board staff Discussion Paper dated July 25, 2006, p. 17). Please provide a table showing a suitable sample of corporate debt issuers with debt issued on 10-year and 30-year term structures.

A14 Board staff has not yet developed such a table.

Q15 Please calculate the return on equity by properly applying Dr. Cannon's methodology based on all relevant data inputs required by that methodology as at August 31st , 2006.

A15 Board staff has asked parties for their opinion of the appropriate application of the Cannon methodology (Please see Board staff question 4).

Staff's calculations are as follows.

Table 1 shows the calculation of the ROE using the initial setup methodology, as documented in the Ontario Energy Board's "Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities" (March 1997) and also in section 5.1 of "A Discussion Paper on the Determination of Return on Equity and Return on Rate Base for Electricity Distribution Utilities in Ontario", by Dr. Cannon (December 1998). This table is provided for illustration purposes, and provides the relevant data for the Long Canada Bond Forecast.

The 3-month and 12-month forecasts of the 10-year Government of Canada Bond yield from the August 14, 2006 Consensus Forecasts are both 4.5%, giving an average of 4.5%. The average difference between 30-year and 10-year Government of Canada Bond yields for all business days during the month of August 2006 is 0.06%. Adding these together gives a Long Canada Bond Forecast of 4.56%. Adding this to an Equity Risk Premium of 3.8% (380 basis points) gives an ROE of 8.36% using the Initial Setup technique.

The ROE can also be calculated using the Adjustment Method. However, the value calculated depends on the starting point. Board staff has used two starting points: a) The 2006 Electricity Distribution Rate Handbook (2006 EDRH); and b) the Transition Rate Order RP-1998-0001 for Distribution and Transmission for Ontario Hydro Services Company (for which Hydro One Networks is the successor regulated transmission and distribution utility).

The starting ROE and the associated Long Canada Bond Forecast using April 2005 data documented in the 2006 EDRH are 9.00% and 5.20%. Applying the Adjustment Method gives an updated ROE based on August 2006 data of 8.52%. These calculations are shown in Table 2.

The starting ROE and the associated Long Canada Bond Forecast using March 1999 data documented in Appendix D of the Addendum to Decision RP-1998-0001 are 9.35% and 5.50%. Applying the Adjustment Method gives an updated ROE based on August 2006 data of 8.65%. These calculations are shown in Table 3.

Table 1
Return on Equity Calculation
Base Year Calculation

Step 1: 10 Year Government of Canada Bond Yield
London Consensus Forecast 14-Aug-06

Date	3-month (%)	12-month (%)	Average (%)
	4.5	4.5	4.5

Step 2b: Average of Actual Observed Spread between 10-year and 30-year Govt. of Canada Bonds

Time Period Aug-06

Average Actual Spread (from Step 2a) (Cell K41) 0.06

Step 2c: Consensus Forecast + Financial Post Spread

Consensus Forecast	4.5	Cell E8
Actual Average Spread	0.06	Cell E16
Final Yield Forecast	4.56	

Step 2d: Equity Risk Premium

Allowed ERP per Board Decision (basis points) 380

Step 2e: Allowed ROE

Final Yield Forecast	4.56	Cell E23
Allowed ERP	3.80	Cell E27
Allowed ROE	8.36	

Step 2a: Calculation of the Average Actual Observed Spread between 10 year and 30 year Govt. of Canada Bonds
Time Period Aug-06

Day		10-year (%)	30-year (%)	Difference (%)
1	01/08/2006	4.31	4.37	0.06
2	02/08/2006	4.32	4.39	0.07
3	03/08/2006	4.33	4.39	0.06
4	04/08/2006	4.3	4.36	0.06
5	05/08/2006			
6	06/08/2006			
7	07/08/2006			
8	08/08/2006	4.28	4.35	0.07
9	09/08/2006	4.32	4.36	0.04
10	10/08/2006	4.33	4.38	0.05
11	11/08/2006	4.36	4.41	0.05
12	12/08/2006			
13	13/08/2006			
14	14/08/2006	4.38	4.42	0.04
15	15/08/2006	4.32	4.37	0.05
16	16/08/2006	4.28	4.33	0.05
17	17/08/2006	4.26	4.32	0.06
18	18/08/2006	4.22	4.29	0.07
19	19/08/2006			
20	20/08/2006			
21	21/08/2006	4.21	4.27	0.06
22	22/08/2006	4.19	4.26	0.07
23	23/08/2006	4.2	4.26	0.06
24	24/08/2006	4.2	4.26	0.06
25	25/08/2006	4.18	4.25	0.07
26	26/08/2006			
27	27/08/2006			
28	28/08/2006	4.18	4.25	0.07
29	29/08/2006	4.16	4.24	0.08
30	30/08/2006	4.12	4.2	0.08
31	31/08/2006	4.11	4.19	0.08
Average		4.25	4.31	0.06

Table 2
Return on Equity Calculation
Adjustment Method

Step 1: **10 Year Government of Canada Bond Yield**
London Consensus Forecast

Date	3-month	12-month	Average	
	4.5	4.5	4.5	%

Step 2: **Average of Actual Observed Spread between**
10-year and 30-year Govt. of Canada Bonds

Time Period	August-2006	
Average Actual Spread (from Step 2a) (Cell K41) of Initial Setup Methodology	0.06	%

Step 3: **Long Canada Bond Forecast =**
Consensus Forecast + Financial Post Spread

Consensus Forecast	4.50	%
Actual Average Spread	0.06	%
Final Yield Forecast	4.56	%

Step 4: **Adjustment Method**

Initial Values	**ROE**	9.00	%	**Date:**	April-2005
	Long Canada Bond Forecast	5.20	%		

Allowed Initial ROE:		9.00	%
August-2006 Long Canada Bond Forecast:	4.56		
April-2005 Long Canada Bond Forecast:	5.20		
Difference in Long Canada Bond Forecast:	-0.64		
0.75 X Difference in Long Canada Bond Forecast:		-0.48	%
Updated ROE using the Adjustment Method		8.52	%

Table 3
Return on Equity Calculation
Adjustment Method

Step 1: **10 Year Government of Canada Bond Yield London Consensus Forecast**

Date	3-month	12-month	Average
	4.5	4.5	4.5 %

Step 2: **Average of Actual Observed Spread between 10-year and 30-year Govt. of Canada Bonds**

Time Period	August-2006
Average Actual Spread (from Step 2a) (Cell K41) of Initial Setup Methodology	0.06 %

Step 3: **Long Canada Bond Forecast = Consensus Forecast + Financial Post Spread**

Consensus Forecast	4.50 %
Actual Average Spread	0.06 %
Final Yield Forecast	4.56 %

Step 4: **Adjustment Method**

Initial Values	**ROE**		9.35 %	**Date:**	March-1999
	Long Canada Bond Forecast		5.50 %		
Allowed Initial ROE:			9.35 %		
August-2006	Long Canada Bond Forecast:	4.56			
March-1999	Long Canada Bond Forecast:	5.50			
Difference in Long Canada Bond Forecast:		-0.94			
0.75 X Difference in Long Canada Bond Forecast:			-0.70 %		
Updated ROE using the Adjustment Method			8.65 %		

Q16 Please confirm that the representative equity market return data is the total return (i.e., the return including the reinvestment of dividends) of that index. Please also indicate the dividend re-investment rate and the amount of appreciation in the market index attributable to the dividend re-investment.

A16 Lazar and Prisman confirm that the representative equity market return is the total return. With regard to the latter two questions, Lazar and Prisman obtained their data from a third party.

Q17 Please indicate whether an analysis of the CAPM using data without dividend re-investment within the market equity index was carried out, and if so, please report the results.

A17 Staff did not specifically request such an analysis from Lazar and Prisman. However, they may have carried out this analysis.

Q18 Please provide the ROEs that would have been generated by the Lazar and Prisman methodology over the past five years and compare these results to the returns granted by the Board and explain any differences.

A18 Lazar and Prisman advise that this would require repeating their analysis as of the beginning of each year in the last five years. Their methodology is explained in their Report. To the extent that there is a difference in the ROE obtained using the two methodologies, the differences stem form the methodologies themselves.

Q19 Please identify all Canadian jurisdictions that rely solely on the Capital Asset Pricing Model when determining the allowed returns on equity.

A19 Board staff has not carried out a comprehensive survey; however, the AEUB does rely on CAPM. In addition, jurisdictions in Europe such as the UK and the Netherlands, use CAPM.

The AEUB states in its Generic Cost of Capital Decision 2004-0052 (July 2, 2004) that:

"On balance, the Board [the AEUB] concludes that the results of the ERP tests other than CAPM would generally support a 2004 ROR above the CAPM estimate, but that for reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM." (p. 23)

With respect to Discounted Cash Flow (DCF), "… the Board concludes that no weight should be placed on the results of the DCF tests presented in this Proceeding." (p. 23)

With respect to Comparable Earnings (CE) tests, "[t]he Board concludes that it should place no weight on the CE test because of the implementation problems of the CE test and the [noted] conceptual and methodological concerns with the CE test." (p. 24)

Q20 Please identify the independent techniques or methodologies that Board staff relied upon to test and confirm the appropriateness of the staff's recommended return on equity approach.

A20 Staff relied on the cost of capital study conducted by Professors Lazar and Prisman on the appropriate cost of capital methodology. Staff then applied their own knowledge of cost of capital, as applied in natural gas regulation in Ontario, and as applied in other jurisdictions (Please see response to CLD Q19),

Q21 Please provide the working papers, including all stated assumptions and data sets relied on, that confirm the proposed rate of return. Please provide the analysis supporting:

- the need to revise the methodology and data supporting the determination of the return on equity; and
- the advantages of the Board staff proposal versus the Cannon methodology.

A21 The need to review the cost of capital for the Ontario electricity distribution sector was recommended by a working group, composed of Board staff and representatives of distributors and other stakeholders, to the Board panel during the Issues Days of the RP-2004-0188 process to develop the 2006 Electricity Distribution Rate Handbook. That recommendation was accepted:

> Mr. Kaiser: Turning to heading B, "Financial Parameters," and dealing with scope and evidence related to that. The Board will initiate an industry-wide process to study return on equity and associated issues in time for implementation into 2008 rates. … (Tr. November 1, 2004, Vol. 1, para. 581)

The studies, reports and presentation materials (including the work of Board staff's consultants) that have been made available through this process are what Board staff have relied upon. The merits of the approach set out in Board staff's Discussion Paper relative to the Cannon approach are identified in the work of staff's consultants.

Q22 Please provide Board staff's updated risk assessment of the Ontario electricity distribution industry. In particular, please provide detailed analysis of the risks to distributors associated with:

- the Ontario Power Authority's Standard Offer Program;
- the Ontario Power Authority's plan to contract with LDCs for CDM; and
- Smart Meters

A22 Board staff does not have a risk assessment of the Ontario electricity distribution industry. Risk as considered by Board staff is on a relative financial basis derived from the work produced by the consultants retained by Board staff.

C. Capital Structure

Q23 Please indicate why the Board staff proposal includes a deemed short term debt component and reconcile this proposal with the Board's plan to examine the working capital allowance as part of its 3 year work plan.

A23 Some distributors have used short-term debt for years to finance their businesses. Since this actually occurs, it seems reasonable to incorporate short-term interest rates into the return on rate base calculations. Lazar and Prisman referred to arbitraging opportunities in their paper. Many distributors have benefited from long-term interest rates being incorporated into rates while the distributors have taken advantage of low short-term interest rates in the past few years.

Hydro One submitted a lead-lag study in its 2006 EDR proceeding to support its working capital requirement. Staff calculated that Hydro One's working capital represents about 8% of its rate base. As discussed on pages 95 and 96 of the September 19, 2006 transcript for the technical conference, staff's proposals for cost of capital do not address how to calculate rate base, including the working capital allowance. This will be part of the development of filing instructions for 2008 rebasing applications.

Q24 Please reconcile the Board's findings on NRG's capital structure (OEB File No.: EB-2005-0544) for the purposes of setting rates, and in particular the Board's reliance on NRG's actual capital structure, with the deemed capital structure proposed in the staff's Discussion Paper dated July 25, 2006. Please be detailed.

A24 The Board's decision on NRG's capital structure and the reasons underlying the Board's determination speak for themselves.

Q25 Please provide the capital structures of each company in the Board staff's proxy sample group. Please provide the weighted average cost of capital for each firm for the years 2001 – 2005, state all assumptions, state all supporting facts and state clearly whether the computed average is on a before or after tax basis.

A25 Appendix A of staff's July 25th Discussion Paper provides the capital structures. The WACC for these companies is not available.

Q26 Please describe the method for adjusting base distribution rates for any costs incurred as a result of a need to achieve compliance with a regulatory instrument. Please describe whether such costs could be treated through the proposed Z factor mechanism.

A26 No specific method for adjusting base rates for compliance with a regulatory instrument has been developed to date. There is a Z-factor discussed in staff's paper that has a number of criteria associated with it that address materiality and associated eligibility.

Q27 Some LDCs may incur increased costs that will not be directly recoverable from generation proponents as a result of anticipated amendments to the Distribution System Code and may incur additional costs to adhere to the anticipated Service Quality Code. Please describe the process for adjusting rates to permit the recovery of prudently incurred costs.

A27 Please see response to CLD question 26.

Q28 Please provide the date on which the Board's deemed cost of short term debt and carrying costs on variance and deferral account balances will be released.

A28 Board staff expects that the accounting guidance applicable to carrying costs associated with regulatory accounts including variance and deferral accounts will be released before the end of November, 2006.

D. Code Implementation/Process

Q29 Please clarify whether the Board staff intends to recommend to the Board that it create a Cost of Capital Code based on a new methodology for determining the allowed rate of return without the benefit of a public hearing designed and administered to thoroughly test the evidence. Please provide examples of previous Code development processes that dealt with similarly complex and key policies. Does Board staff believe that a Cost of Capital and IRM Code will impact LDC interests in a way that is comparable to the interests affected by other Codes that the OEB has promulgated in the past (like the Distribution System Code or the Affiliate Relationships Code)?

A29 The Board has determined that the cost of capital and incentive regulation methodologies will be embodied in Codes. The legislation is clear regarding the notice and comment process that applies to the issuance of a Code. That process is not contingent on the complexity of the issues to be addressed through a Code.

Q30 For the Enbridge Gas Distribution Inc. and Union Gas Ltd. proceedings on establishing return on equity (OEB File Nos.: RP-2002-0158/EB-2002-0484) please provide a table that identifies and chronologizes all the events, their respective dates and categorized as:

- Administrative/Process milestones;
- "Evidentiary" filings;
- Decision Making milestones (e.g. filing of Board staff's original discussion paper, revised discussion paper, etc.)

A30 On January 16, 2004, the Board issued a Decision and Order in respect of applications by Union Gas Limited and Enbridge Gas Distribution Inc. for a review of the Board's guidelines for establishing their respective Return on Equity. All material related to these applications is available at the Board's offices. The Decision and Order contains a description of the proceeding and is also available on the Board's web site and at the Board's offices during regular business hours.

Q31 Please identify all other Canadian regulators that rely on a Code or other mandatory licence conditions or rules, for the purposes of establishing just and reasonable rates. Agencies should include those involved in regulating electricity distribution, transmission, natural gas and water/waste water services.

For each example please provide:

- a concise description of the process relied on to establish the Code/licence condition/rule;
- the schedule of events that culminated in the making of the subject code/licence condition/rule;
- a comparison of the enabling legislation of that jurisdiction to that contained in the *Ontario Energy Board Act, 1998*, as amended.

A31 Please see response to CLD Q4.

Q32 Please discuss the techniques available to the Board and to LDCs if the distribution rates established by adhering to the proposed Codes for any given rate year do not permit the adequate recovery of prudent costs incurred to provide distribution service.

A32 The Board's approach involves amendments to a distributor's licence that would require the application of the cost of capital and incentive regulation methodologies for rate-setting purposes. A distributor that believes that this will not result in just and reasonable rates may apply to the Board for an amendment to its licence that allows for rates to be set on a different basis.

Q33 Please identify and describe each step of a Code based rate setting process. Please confirm that the Board must issue orders setting just and reasonable rates.

A33 The Board will issue the Code(s) with respect to the cost of capital and incentive rate methodologies in accordance with the notice and comment process required by statute. Board staff expects that this will be followed by filing guidelines or requirements that identify the information to be filed by distributors for rate-setting purposes. The rates for each distributor must be embodied in a rate order issued under section 78 of the *Ontario Energy Board Act, 1998*.

Please also see response to CLD Q4.

Q34 Please describe whether Board staff intends to recommend that the Board establish a formula in the new Codes to establish Cost of Capital and IRM components or whether the Codes will simply establish numerical values for the key variables (e.g. the Codes would simply prescribe 9% ROE, 6% Debt Rate, 60/40 D/E Ratio, etc.):

- if providing a formula in the Code is chosen, identify and describe:
  - where the Board/Board staff intends to source data to populate the formula;
  - how the Board/Board staff intends to select the point in time when the data is taken.
- if establishing fixed numerical values for key Cost of Capital and IRM variables is the recommended Code approach, please explain:
  - how the numbers will be determined, from what source the data will be derived, and the process contemplated to adjust those numbers in future years.

A34 The method proposed by staff contains both variable and constant terms in a formula.

It is expected that the Codes would indicate as explicitly as possible what the source data would be as the inputs for calculating the formulas when they are needed, and the dates to be used. This approach is similar to that used for updating the ROE in setting the revenue requirement for gas distributors.

Board staff views are documented in its July 25th Discussion Paper.

Q35 Please provide the LDC filing guidelines that Board staff will rely upon for purposes of establishing just and reasonable distribution rates effective May 1, 2007. In particular, please provide direction on the criteria for seeking approval of variance or deferral accounts and the criteria for disposing of any balances recorded in such accounts, both favourable and unfavourable, through rates.

A35 Please see response to CLD Q33.

Q36 Does Board staff believe that the views and assessments of the financial community are irrelevant in determining appropriate rates of return, deemed capital structures and more generally, regulatory rules for the companies that the Board regulates?

A36 All informed views are relevant, if not always persuasive. Staff takes no position on the views of the financial community in particular, but notes that certain of those views have been brought forward anecdotally by participants in this process.

Q37 In developing its positions on issues related to capital structure and the cost of capital, did Board staff or the Board consult members of the financial community to assess their views on the appropriateness of the proposed approach, or have Board staff relied largely on the analyses provided by members of the academic community? If the financial community was consulted, please provide documentation of the discussions, copies of correspondence that was exchanged and details of the views or opinions that were expressed.

A37 This process has been designed to gain insights on cost of capital and incentive regulation from all interested parties. From time to time, staff does meet informally with members of the financial community. Staff has not actively solicited the views of the financial community on its cost of capital and incentive regulation proposals, beyond providing due notice of this process and allowing participants to bring forward information that they consider to be germane. Staff notes that some of those views have been brought forward anecdotally by participants in this process. All information related to these consultations has been posted on the Board's web site.

Q38 Reference: OEB Staff July 25, 2006 Discussion Paper, pages 17 and 20:

(a) Do staff anticipate any adjustment to ROE for
(i) the existing rate base; or
(ii) new infrastructure added in 2007 or beyond,
during the 2007-2010 2nd Generation IRM period once ROE has been established for 2007? If so, what will be the basis for adjustment, and more particularly, what will be the sources of the data used in the calculation of the adjustment?

(b) Will the 50-150 basis point premium discussed in Section 2.3.3 be adjusted annually? If so, what will be the basis for adjustment, and more particularly, what will be the sources of the data used in the calculation of the adjustment?

(c) What will be the sources of the data used in establishing the debt rate for the 2007 rate year (both the risk-less rate and the bond market spread)?

(d) Will the Code confirming the cost of capital to be used in adjusting annual revenue requirements for 2007 and beyond provide for any adjustments to the debt rate during the 2008-2010 period? If not, explain why not. If so, please describe the adjustment methodology, and the source of the data to be used in the revised debt rate calculation.

(e) If not, when do staff anticipate the next setting of the debt rate?

(f) Please indicate those changes in market returns that are tracked in the inflation proxy and those that are not.

A38 (a) No. Only when distributors are rebased beyond 2007.

(b) No, if adopted, the basis point premium would not be adjusted.

(c) The sources of the data are the Bank of Canada for the riskless rate and an appropriate sample, as yet to be determined, of the corporate bonds.

(d)(e) No, existing debt would not get adjusted from what was allowed by the Board in 2006 rates. As outlined in staff's Discussion Paper, the deemed rate for new debt would be adjusted.

(f) Please see response to CLD Q47. Board staff has posed a similar question to participants in this process (Board staff question #5).

Incentive Regulation

Q39 Has Board staff performed any analyses to determine whether Ontario distribution utilities are more or less efficient than publicly or privately owned distribution utilities in the U.S., the U.K. or elsewhere? If so, please provide the analyses.

A39 Board staff has not conducted any such analyses, but has relied on the expert analysis provided by staff's consultant, Dr. Lowry.

Q40 At p. 19 of the Staff Discussion Paper of July 25, 2006, Board staff indicates that its proposed approach for Ontario was informed by a report prepared by Dr. Mark Lowry. Evidently, less than 3 pages of Dr. Lowry's 88 page report (Second-Generation Incentive Regulation for Ontario Power Distributors, June 13, 2006, pages 86-88), are devoted specifically to a discussion of a 2nd generation incentive regulation plan for Ontario distributors. Please provide copies of any additional analyses, reports or correspondence, prepared by Dr. Lowry or others, that Board staff has relied upon in arriving at its proposed 2nd generation approach.

A40 In addition to Dr. Lowry's report, Board staff has relied on its own knowledge and expertise regarding both incentive regulation and Ontario distributors. For example, incentive regulation has been examined in detail in proceedings RP-1999-0034 and RP-1999-0017, as well as in the Natural Gas Forum. Materials associated with those initiatives are available for inspection at the Board's offices during regular business hours. Some of the materials (including final decisions and reports) are also available on the Board's website.

Q41 In calibrating the proposed price-cap rule, what analyses has Board staff relied upon to ensure that rates are sufficient so that utilities can meet their OM&A costs, their needed capital program costs and at the same time achieve regulated rates of return? Please provide copies of any such analyses.

A41 A core principle in incentive regulation is that, unlike in cost of service regulation, there is not a one-to-one relationship between costs and revenues.

Staff has assumed that the 2006 Board-approved rates is the appropriate starting base for 2nd Generation IRM.

Staff is not clear what is meant by "calibrating the proposed price-cap rule". However, staff is of the view that it is not necessary for the methodology proposed by staff to result in the same revenue requirement as that which would be achieved by a cost of service review.

Q42 At p. 19 of the Staff Discussion Paper, it is stated that "The objectives of the 2nd Generation IRM are to: provide regulatory certainty to distributors during the Rate Plan as several rate-related studies are carried out; drive efficiency improvements in the distribution sector; and lay a foundation for the 3rd Generation IRM." Please explain how the proposed price-cap rule will drive efficiency improvements in electricity distribution. What new incentives are likely to be generated that were not already present? Please explain in what sense the proposal will lay a foundation for 3rd Generation IRM, keeping in mind that at page 19 it is stated that "The approach suggested below is independent of the development of 3rd Generation IRM."

A42 With regard to efficiencies, please see response to CLD Q7.

The experience gained during 2nd Generation IRM will inform the development of 3rd Generation IRM.

Q43 At p. 21 of the Staff Discussion Paper, Board staff report that preliminary calculations of the "K-factor" indicate that for 2007, the value could be between -2% and +2% and for 2008 it could be between -1% and -3%. Please provide copies of the preliminary calculations that were performed. Could some utilities experience a two-year cumulative impact of -5%?

A43 Please see response to EDA Q3.

Q44 At p. 39 of the Staff Discussion Paper, Board staff proposes that the forthcoming 2008-2010 reviews be based on a forward test-year cost of service filing. Please provide any analyses or reasoning upon which this proposal is based. Would such an approach be consistent with a "British-style" approach to incentive regulation? Is Board staff recommending against an approach which would be based upon a multi-year filing?

A44 The Board has identified in its multiyear rate setting plan for electricity LDCs that it would conduct a cost of service rebasing for LDCs in three tranches in 2008, 2009, and 2010. A forward test year application is a standard methodology to conduct such a rebasing, in particular if it leads to a multi-year incentive mechanism.

With regard to rate-making subsequent to the rebasing, work on 3rd Generation IRM has not started.

Q45 Has Board Staff given any consideration to improving the incentive properties of the price-cap rule that has been proposed for the interim period? If so, please provide specific details. Have any mechanisms for ensuring that realized savings are retained for a reasonable period of time been considered? If such mechanisms were considered, please provide specific details.

A45 If the CLD believes there are ways to improve incentives during the interim period and ways to facilitate appropriate retention and sharing of savings, the CLD in their final written comments to the Board can identify their preferred approaches, how they differ from staff's, and why they are preferred.

Q46 Please provide Board staff's analysis of the appropriateness of proposing a higher productivity factor after a period of imposed distribution rate freeze and a period of protracted rate stability. Please analyze the advantages and disadvantages of permitting LDCs to file individual productivity factors.

A46 Staff is not proposing a higher productivity factor. Staff notes that the value for the X-factor in first generation PBR was 1.5%.

If the CLD is of the view that distributors should be able to file individual productivity factors for 2nd Generation IRM, the CLD in their final written comments to the Board can outline the detail of the option, its rationale, and its implementation.

Q47 Please analyze the correlation between:

- GDP-IPI and LDC costs; and
- CPI and LDC costs.

A47 Staff has not commissioned empirical research on this. However, a discussion of these macroeconomic inflation measures that have been used in approved indexing mechanisms is available in Dr. Lowry's report (page 38), and in staff's Discussion Paper.

Q48 Please provide the staff's position and supporting rationale with respect to the Capital Investment Factor proposed by Hydro One's expert. Please describe any alternatives to such a factor.

A48 Please see response to HONI Q3(b) under heading "2nd Generation IRM - How will the proposals be implemented?"

Q49 Staff contemplates reviewing and refining the IPI methodology employed in 1st generation PBR for consideration in 3rd Generation IRM.

(a) With 2nd Generation IRM to be in place for up to 3 years, are there any refinements to the GDP-IPI approach recommended for 2nd Generation IRM that staff would consider appropriate?

(b) How has Ontario GDP-IPI differed historically from Canada GDP-IPI for Final Domestic Demand?

(c) What adjustments could be made to Canada GDP-IPI for Final Domestic Demand in order to more closely approximate Ontario GDP-IPI data?

A49 (a) No.

(b) Please see the following table:

GDP-IPI (Final Domestic Demand) – Canada and Ontario:
Annual – 1981 to 2005 (1997 =100)

	1980	**1981**	**1982**	**1983**	**1984**	**1985**	**1986**	**1987**	**1988**	**1989**
Canada		58.6	64.1	67.7	70.4	72.9	75.7	78.7	81.6	85.2
Ontario		57.1	62.4	66.2	69.1	72.0	75.2	78.8	82.3	86.2
	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Canada	88.4	91.4	93.0	94.9	96.3	97.4	98.5	100.0	101.3	102.6
Ontario	89.2	92.3	93.4	95.3	96.4	97.6	98.6	100.0	101.5	102.6
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Canada	105.0	106.8	109.3	110.8	112.7	114.7				
Ontario	105.1	106.9	109.2	110.7	112.5	114.3				

Source: Statistics Canada CANSIM
GDP-IPI (Final Domestic Demand) – Canada: Table 384-006, series V3840594
GDP-IPI (Final Domestic Demand) – Ontario: Table 384-006, series V3840768

(c) Given that the two indices track closely, Board staff does not consider that adjustments to Canadian GDP-IPI (Final Domestic Demand) are necessary.

D. Data

Q50 Please identify and discuss the appropriateness of linking the term of the risk free rate to expected life of distribution assets. Please discuss the risk free rate used by bond and credit rating analysts. Please discuss whether the use of the zero coupon bond rate biases the allowed rate of return.

A50 Staff is of the view that as a general principle the term structure of liabilities should match that of assets. For long lived assets, like those of distributors, since yield curves vary continuously, the best that can be done is to choose a single rate that best reflects the likely riskless rate over the life of the assets. Lazar and Prisman discuss the relative advantages of different methods. Staff does note that the question seems to misunderstand the proposed method in that Lazar and Prisman fit their curves to the full range of inferred zero-coupon bond yields, up to 30 years. The averaging method focuses on the 5, 10 and 15 year values of the fitted curve but the curve itself is fitted to inferred bond yields of up to 30 years.

Lazar and Prisman add that the use of other methods, than the zero coupon bond rate, would cause a bias in the ROE. The riskless or risk-free rate is not constant over time. Periodic adjustments are to be made to both the riskless rate and the ROE and cost of debt (in the case of LDCs with no third party debt) because the riskless rate, as well as the market returns and risk spreads do change over time. The frequency and nature of these adjustments are much more important than minor differences that may arise because our methodology is used rather than some other, or that we smooth the yield curve.

Q51 Please provide Board staff's working papers concerning the diagnostic statistics of the computed beta for the sample firms. Please provide the rolling 5 year beta and the rolling business cycle beta for each firm. Please provide the 90% and 95% confidence bands for the calculated beta. Please describe all normalizing calculations and supporting assumptions.

A51 The betas were provided by Lazar and Prisman. Please see response to CLD Q16.

Electricity Distributors Association (EDA)

Q1 Please provide the source(s) for the data used in arriving at the ratios used in Tables 1, 2, 6 & 8 of the report "Calculating the Cost of Capital for LDCs in Ontario." Please provide definition(s) of the ratios used in the tables, and cite any references employed to develop these definitions.

A1 The data used in arriving at the ratios used in Tables 1, 2, 6 and 8 of the report "Calculating the Cost of Capital for LDCs in Ontario" was provided by Board staff. The data comes from reporting by LDCs under the Board's Reporting and Record-Keeping Requirements (RRR) system. The financial information comes from the trial balance of the Uniform System of Accounts filed by distributors under section 2.1.7 of the RRR. Consistent with the approach used in the process associated with the development of the 2006 EDR Handbook, the data was used at an aggregated level.

Q2 On page 13 of the Staff Discussion Paper, issued July 25, 2006, it is stated that "While there are several dimensions of risk that vary across utilities, such as load concentration, total load, etc., staff finds that there is no reasonable way to differentiate them". Have Board staff completed any studies of the differences in risks across utilities in Ontario to support this finding? If so, please provide these studies or analyses.

A2 If the EDA believes that additional information (from any source, including distributors) would allow assessment of significant differentiation, the EDA in its final written comments to the Board can detail those studies or analyses. Absent such information, staff does not have a way to support a non-arbitrary way to differentiate between distributors.

Q3 On page 21 of the Staff Discussion Paper, issued July 25, 2006, it is stated "Staff has carried out some preliminary calculations on this proposed approach to calculating "K". Based on these calculations the 2007 K-factor could be between -2% and +2%, depending on the Board's determination of the 2007 ROE. The 2008 K-factor to adjust for capital structure change could be between -1% and -3%". Please provide the calculations that were used in arriving at the K-Factor for 2007 and 2008. Please cite any references used in developing these calculations, and provide any supporting documentation used.

A3 The range cited in Board staff's Discussion Paper is intended to be illustrative. If Board staff's proposed approach is adopted, then the K-factors will be calculated based on the methodology documented in the Cost of Capital Code and based on the parameters to be used for setting the ROE.

The preliminary estimates of the K-factor were done using the methodology documented in Appendix A of the July 25th staff Discussion Paper. Using the final 2006 EDR spreadsheets corresponding to Board-approved tariffs for a random sample of distributors of various sizes, staff applied the methodology to determine the percentage changes in the base revenue requirement for: first, the change in the ROE to an estimated value of 8.7% for 2007 (as a potential real ROE based on the Cannon methodology); and second, the change from the deemed size-related capital structure applicable to the utility in its 2006 EDR application to a common 60:40 D/E structure. The variability and convergence of results were then assessed. Some alternative values of ROE were examined for some files to assess the sensitivity of the approach to various values of ROE. Based on the analysis of limited data, staff has estimated this range of K-factor values, which may correspond generally to a range in the ROE from about 8.3% to 9.8%, but Board staff cautions that these are preliminary estimates. However, preliminary analysis indicates that the K-factors that would apply to most utilities may have less of an impact than is suggested by the range of the estimates provided in the staff Discussion Paper.

The spreadsheets are not attached given their size, but are available upon request.

Hydro One Networks, Inc.

<u>Cost of Capital</u> - Where do we go from here?

Q1 The Board's Staff proposal for a common capital structure and a common ROE simplifies the requirements for the Rate Plan period during the 2nd Generation IRM. It is a well know fact that the distribution businesses in Ontario are not uniform in either a financial or physical sense. Therefore, looking forward beyond that period there are concerns with maintaining a common approach which does not recognize diversity of utility structures (urban vs. rural), the varying customer base (customer density and proportion of industrial customers), cost levels (Capital & OM&A), and business risks (financial structures).

(a) What factors need to be considered by the Board to give consideration to move away from the common cost of capital consideration and what information would have to be gathered in this respect?

(b) If the Board is not prepared to recognize the need to differentiate between utilities, how will the Board propose to deal with the fact that differences will continue to exist in the utility sector despite the Board's intent to rationalize the industry to a common financial model where there is no accompanying physical rationalization?

A1 (a) Staff is of the view that distributors are more alike than they are different with respect to the risks that they face. The factors that might be considered for exemption may include the unique business and operational risks of an LDC.

(b) If Hydro One is of the view that distributors should be differentiated in their capital structure, Hydro One in its final written comments to the Board can detail why and how such differentiation should occur.

Also, please see response to CLD 32.

Q2 The Board's proposal to enshrine the cost of capital parameters in a Code raises a number of questions looking beyond the 2nd Generation IRM.

(a) How would the proposed Code accommodate the move to 3rd Generation IRM and would it be necessary to continue with the Code post 2nd Generation IRM?

(b) Could the cost of capital parameters be a part of the incentive mechanisms under a 3rd Generation IRM?

(c) Will the capital parameters be set uniform for all utilities or will the Board take into consideration the difference in business risks across the utility sector to establish parameters to be utility specific or to group utilities into categories? If not why not? What criteria would the Board use to differentiate risk between utilities?

A2 At this time, the mechanism to implement 3rd generation IRM has not been determined by the Board. Board staff has not considered how the proposed code would be affected by a 3rd generation incentive mechanism. The cost of capital code would remain in effect until changed.

Q3 There is an enduring concern about the use of appropriate industry references for the purpose of assessing cost of capital requirements for the electricity distribution sector in Ontario. The norm is to use the natural gas and electric utilities in North America as the applicable reference.

(a) What does the Board envisage as a suitable industry reference moving forward beyond rebasing and into the 3rd generation IRM?

(b) By what process will the Board determine the suitability of the industry reference?

A3 Please see response to HONI Q2 under heading "Cost of Capital – Where do we go from here?"

Cost of Capital – How will the proposals be implemented?

Q1 The Board proposes to establish a separate Code (under proceeding RP 2006-0087) that will confirm the cost of capital to be used in adjusting the LDCs annual revenue requirements for 2007 and during the Rate Plan period. It is assumed that the proposed Code will include the same amount of detail in respect of the level of RoE and the capital structure as is currently contained in the Distribution Rate Handbook.

(a) What process will the Board adopt to amend the Code to deal with changes to the cost of capital parameters beyond 2007 and what will be the associated timelines?

(b) Will these timelines be established to coincide with the current timelines for adjusting distribution rates in May 1 of the year?

(c) Will the process allow sufficient time for LDCs to make the necessary changes to their rate schedules for implementation by the required rate change date, particularly for those utilities that to date have not been able to harmonize their distribution rates?

A1 (a) A mechanistic process for annually adjusting cost of capital parameters is expected to be built into the Code. Any necessary Code amendments would proceed through a typical Code amendment process. The timelines would be reflective of the requirements under section 70.2 of the Act.

(b)&(c) Under the current rate plan, annual adjustments are expected to be effective May 1.

Q2 As proposed by the Board Staff the process to establish the cost of capital entails the determination of (i) the capital structure, (ii) the equity risk premium, (iii) return on equity, and (iv) the debt rate.

(a) Will the Board set the above parameters on an annual basis or one time for the duration of the Rate Plan?

(b) Will the Code be prescriptive and contain specific formulae to calculate the parameter adjustments or will it contain a description of the approach to do the calculations? What information will be required to perform the calculations and what will be the source of that information?

(c) Is there a requirement for LDCs to provide any information to assist the Board in setting the parameters or will the Board establish these parameters without any LDC input?

A2 (a)&(b) Please see response to CLD Q34

(c) If the methodology set out in the staff Discussion Paper is adopted, staff foresees no requirement for electricity distributors to provide any input on these parameters because all of the data is from publicly available sources.

Cost of Capital – Specific Request for Clarification

Board Staff

Q1 Reference: Board Staff Discussion Paper dated July 25, 2006, Appendix A.

(a) Would Staff agree that it would be appropriate to remove Coast Mountain Power from their samples since it has been acquired?
(b) If the answer to (a) is yes, would Staff then agree that the average levered 60-week beta for the sample of All Rate Regulated Companies is approximately .70?
(c) Would Staff also agree that the approximately .70 beta for the sample excluding Coast Mountain is virtually identical to the unlevered .357 beta originally proposed by Drs. Lazar and Prisman when relevered for a 60%/40% debt/equity capital structure as shown in their June 20, 2006 presentation?

A1 If Hydro One is of the view that there is a more appropriate sample of companies to be referenced, Hydro One in its final written comments to the Board can identify its preferred sample, how it differs from staff's, and why it is preferred.

Q2 Reference: Board Staff Discussion Paper dated July 25, 2006, p.12.

Preamble: Staff recommends that only the inputs to the formula be updated annually to minimize uncertainty about changing formulae or parameters. Could Staff please clarify what the formula is to which they are referring, and specifically what parameters they are recommending be updated?

A2 The formula is: WACC = %D*Drate + %E*ROE, where the latter is given by riskless rate + beta*MRP (where MRP = MR-riskless rate) and the debt rate (Drate) by the riskless rate plus the spread of a sample of A/BBB corporate bonds over the Canadas of the same duration.

The inputs are the riskless rate and debt and equity ratios; the parameters are beta and MRP (and the underlying samples); and the samples for the spread between corporate A/BBB and Canadas.

Q3 Reference: Board Staff Discussion Paper dated July 25, 2006, p.12

Preamble: Staff states that Lazar and Prisman provide a simple spreadsheet mechanism that smooths the Bank of Canada data over a rolling six year period. Could Staff explain in more detail what the rolling six year period is to which they are referring?

A3 The six year rolling period is the six years prior to the year of calculation (e.g. the average for year six is the average of the six years to that point) – a standard way to compute rolling averages. However, Lazar and Prisman actually recommend a sixth degree polynomial curve-fitting which is similar way of smoothing the yield curves but not exactly the same.

Q4 Reference: Board Staff Discussion Paper dated July 25, 2006, p.16

Preamble: Staff states that they have focused on using the shortest and longest terms available.

(a) Could Staff please verify that the forward rate that they used to derive the 8.37% ROE was not the 15 year rate, but was an average of the 5, 10, and 15 year rates?
(b) Could Staff please verify that the 15-year forward rate, according to the Lazar and Prisman interest rate file was 5.54%?
(c) Please explain why a longer term forward rate could not be estimated from the data and equations that were made available by Drs. Lazar and Prisman?

A4 (a) Yes, that is correct.
(b)&(c) Please see HONI Q3 to Drs. Lazar and Prisman under heading "Cost of Capital – Specific Request for Clarification"

Q5 Reference: Board Staff Discussion Paper dated July 25, 2006, Appendix A

(a) Would Staff verify that the market returns of 8.09% and 10.06% used to estimate the risk premium are geometric averages?
(c) Would Staff please confirm that both Ms. McShane and Dr. Booth are of the view that arithmetic averages should be used to estimate the cost of equity?
(d) Could Staff please confirm that the EUB in their generic cost of capital Decision 2004-052 and the BCUC in its March 2, 2006 ROE decision for Terasen Gas both concluded that it was appropriate to use arithmetic averages in estimating the market risk premium?
(e) Could Staff please provide the arithmetic average returns corresponding to the 8.09% and 10.06% used in Appendix A?

A5 (a) Staff is seeking a response from Drs. Lazar and Prisman.

(c)(sic) & (d)
The views of Ms. McShane or Dr. Booth should be confirmed with them, and not with Board staff. Similarly, regard should be had to the EUB's decision for confirmation of the EUB's conclusions in the decision referred to. If Hydro One believes that arithmetic averages should be used to estimate the cost of equity, then it can make that comment and provide reasons why this is a preferred methodology.

(e) Staff is seeking a response from Drs. Lazar and Prisman.

Q6 Reference: Board Staff Discussion Paper dated July 25, 2006, pp. 12-13

Preamble: Staff recommends a common equity ratio of 40%, but included in the 40% are any preferred shares issued by the distributor up to a maximum of 4%.

(a) Is it Staff's opinion that preferred shares are equivalent to common equity? If not, please explain the justification for the proposal to include in the 40% up to 4% preferred shares?
(b) Staff says that a thicker common equity ratio is justified for the LDCs than for the gas distributors. Can Staff confirm that both Enbridge Gas and Union Gas also have some preferred shares in their regulated capital structures?
(c) If an electric LDC had 36% common equity and 4% preferred shares, would its total equity ratio be significantly different from that recently approved for Union Gas?
(d) If it is Staff's intention for the electric LDCs to have thicker equity than the gas LDCs, and the gas LDCs have preferred shares in addition to common equity, would Staff's objective be met if its proposal to include up to 4% preferred shares in the 40% equity were approved by the Board?

A6 (a) The Discussion Paper identifies preferred shares as a component of equity.
(b) In its last rate application decided by the Board (EB-2005-0001/EB-2005-0437), Enbridge has an allowed 35% common equity and 2.77% preferred shares. In its last rate application decided on by the Board (EB-2005-0520) Union Gas has an allowed 36% common equity and 3.4% preferred shares.
(c) No, they would be the same.
(d) If Hydro One believes there is an approach that is preferable to staff's, Hydro One in its final written comments to the Board may wish to identify its preferred approach, how it differs from staff's, and how it is preferable.

2nd Generation IRM - Where do we go from here?

Q1 Hydro One supports the adjustment proposal for transition; and is of the view that the industry needs to progress quickly to conclude its implementation and to start consultations on the longer term 3rd Generation IRM (3GIRM) regime.

(a) When will the Board release a timetable for process and stakeholder consultations for developing the 3GIRM.
(b) Since the Board is disposed to LDCs nominating their submission in respect of rebasing to any of the recommend cohorts, can the Board provide guidelines on the type of information it will need from the LDCs for self-nomination?

A1 (a) Stakeholder consultations for developing the third generation incentive regulation framework are expected to begin in the first quarter of calendar 2007.

(b) Within the next few months, Board staff will provide an opportunity for industry participants to comment on the selection criteria that will be recommended for the Board to use in deciding which LDCs to map to one of 2008, 2009 or 2010 for rebasing.

Q2 The board had not set out an indicative threshold for quality assurance but rather proposes to use the current SQI's and performance measurements.

(a) What procedure will the Board adopt to ensure adherence to the standards of service; for example, penalties for deterioration and rewards for improvements.
(b) What incentives does the Board intend to use in the 3GIRM and how will they be determined? How will the Board assess whether a LDC can attain the proposed thresholds?
(c) How will the Board link SQI thresholds with the investments that an LDC needs to maintain the minimum standards of service?

A2 As indicated on page 20 of its June 20, 2006 report and on page 29 of its July 25, 2005 Discussion Paper, Board staff has recommended that the Board resume its SQR review. The issues referred to in your question have not yet been determined, and may be addressed as part of that review.

Q3 The Board has provided factors that need to be considered in developing the 3GRIM. Looking beyond the transition period,

(a) What are the principles that underpin the incentive plans that the Board intends for the LDCs after 2nd Generation IRM (2GIRM)?

(b) What lessons has the Board learned from other jurisdictions that successfully implemented incentive regulation; and how is the Board going to apply these to the design of an effective 3GIRM?

(c) What procedures and plans does the Board have to constituting stakeholder Work Groups that will assist it in developing the 3GIRM?

(d) Please describe how the Board intends to encourage the LDCs to make efficiency savings during the incentive regulatory periods; and how the Board might link investments and efficiency?

(e) To what extent has the Board gone to confirm whether beyond 2007, its 1% productivity factor proposal will be an appropriate level in Ontario? What types of information will the Board require to ensure that its long term incentive regime reflects the inherent features of the Ontario electricity distribution industry?

(f) Will the Board move to judge productivity on an individual basis? If so, Hydro One believes that LDCs may need to demonstrate viability to serve their customers; therefore, can the Board provide some guidelines on the following:

i. Information about the condition of assets.
ii. How might the Board consider linking rewards and penalties to a LDCs ability to serve?

(g) Given the differences in the efficiency levels between LDCs in Ontario, what procedure can the Board use to categorize or perhaps implement LDC specific productivity levels?

(h) How does the Board plan to deal with negative productivity factors; where relevant, how will the Board apply lower productivity factor across all LDCs?

A3 Work on 3rd Generation IRM has not started. Please also see response to HONI Q1(a) under heading "2nd Generation IRM - Where do we go from here?"

2nd Generation IRM – How will the proposals be implemented?

Q1 The Board proposes a simplified and transparent regime, in which the governance of the IRM will be done by a Code.

(a) What procedure will it use to establish the components of IRM; for example the inflation factor?

(b) If necessary, how will the Board modify these components; who can raise the need for a modification; the timetable for industry consultations and dissemination of final decisions?

A1 (a) This process will establish the components of IRM.

(b) Please see response to HONI Q1(b) under heading "Cost of Capital - Where do we go from here?"

Q2 It is assumed that the Board will define the productivity factor.

(a) If the Board needs to alter the productivity factor in response to low growth and / or to capital investment, can the Board reveal how it might calculate the new factor? Has the Board performed any scenario analysis in this respect and if so could it share that analysis with the industry?

A2 Staff has not carried out scenario analysis in relation to these matters.

Board staff does not currently see the need for any adjustment to be made to the productivity factor while the 2nd generation incentive mechanism is in place. However, staff in its September 27th questions to parties seek input on the issues of low growth (please see staff question #11) and capital investment (please see staff question #9).

If Hydro One believes that such adjustment may be appropriate, Hydro One in its final written comments to the Board can detail what the adjustment might be and how it might be calculated.

Q3 The Board has recommended a price cap formula for the transition period.

(a) What plan and procedure will the Board use for periodic assessments of the LDCs operations to ensure applicability throughout the Rate Plan period?

(b) How will the Board treat new investments? Hydro One recommended that the Board includes a CI factor in the 2GIRM model; reference Hydro One's presentation at the technical conference. There was significant discussion on the topic at the Technical Conference but Hydro One did not hear any dismissal of the proposal. Can the Board provide feedback on the proposal and identify any shortcomings that it feels might inhibit its implementation in the 2GIRM?

A3 (a) The Board currently requires LDCs to submit periodic RRR filings. These filings are reviewed by the Regulatory Audit group, whose functions include monitoring the financial status of electricity distributors.

(b) Staff has not taken a position with respect to the proposed CI-factor or to alternatives to it, but is seeking further elaboration on the CI-factor as proposed and on other approaches through questions addressed to other parties, including Hydro One Networks (please see staff questions 9 and 10).

Q4 The Board Staff proposes allowance for 'Z' Factors in the 2GIRM model. There was some discussion at the Technical Conference regarding the process for utilities to make submissions for Z-factor consideration.

(a) What process is the Board planning to adopt in this respect that will reflect the mechanistic nature of adjustments to prices during 2GIRM?

(b) What should LDCs expect to be required to submit as supportive material for the 'Z' factor adjustments?

(c) Given the nature of 2GIRM can the LDCs assume that approvals of such submissions will not require a public review, and if not then why not? What requirements would the Board need to expedite the process and make it mechanistic?

A4 As part of its filings for rate-setting purposes, each distributor would provide information that would enable the Board to determine whether a Z factor adjustment is required based on the criteria set out in the Code. These filings will be publicly available.

Q5 If the Board has concerns about Hydro One's CI factor and considers using deferral account regime as a way by which to capture incremental capital costs during 2GIRM,

(a) What will be the basis for a LDCs qualification to use the deferral accounts?

(b) What tracking period as well as timetable for reviews of the amounts in the accounts should the LDCs' expect?

A5 (a) Board staff has not yet considered what qualifying criteria would be necessary and appropriate for approval of deferral accounts to track incremental non-load growth-related capital investments.

(b) The tracking of approved deferral accounts is reported to the Board under section 2.1.1 of the Board's Reporting and Record-Keeping Requirements. This requirement is due quarterly using the Board's RIFS System. Under section 78(6.2) of the *Ontario Energy Board Act, 1998*, the Board is required to determine, at least annually, whether and how amounts recorded in a deferral or variance account that does not relate to the commodity of electricity are to be reflected in rates.

If Hydro One Networks believes there is a preferable approach ("CI factor" or other) for regulatory treatment of incremental capital investments in terms of both qualifying, and of subsequently disposing of booked amounts, then Hydro One in its final written comments to the Board can outline its proposal(s) and the rationale for its proposal(s).

Q6 Has the Board assessed whether the existing SQIs and performance measurement metrics adequately represent the utility sector in Ontario and if not what procedure will the Board follow to redress this matter? Does the Board plan to review the SQIs during the period of 2GIRM?

A6 Please see response to HONI Q2 under "2nd Generation IRM – Where do we go from here?"

Bluewater Power

Page 1 **Q1** Given that the Board Staff is recommending one debt/equity structure for all LDC's, please explain why Board Staff did not commission Dr Lazar and Dr. Prisman to conduct an anaylsis to determine whether one debt/ structure is appropriate for all LDCs?

A1 Staff contracted with Drs. Lazar and Prisman to provide advice on the cost of capital; they were not asked to recommend on any particular capital structure.

Q2 Does Board Staff agree that such an analysis would be of assistance to the Board in determining whether it is appropriate to move from the current deemed debt/equity structures? Why or why not?

A2 Lazar and Prisman considered different approaches to establishing the debt/equity structure(s) for distributors. If there are additional analyses regarding the move from the current debt/equity structures that Bluewater Power believes may be of assistance to the Board, then Bluewater Power may wish to include those analyses in its final written comments to the Board for its consideration.

Q5 Does Board Staff have any evidence that suggests the current deemed debt/equity structures for LDCs in Ontario are wrong (i.e. do not accurately reflect the risks faced by LDCs)? If so, please provide that evidence.

A5 Staff has found no evidence to suggest that the current debt/equity structures are reflective of utility risk.

Page 2 **Q4** If Dr. Lazar and Dr. Prisman's recommendation for 2 debt/equity structures was <u>not</u> based on transitional reasons, but was rather based on actual reported data, would Board Staff support the debt/equity structures recommended by Dr. Lazar and Dr. Prisman? Why or why not?

A4 As discussed at the technical conference (please see page 120, September 20, 2006 transcript of technical conference) Drs. Lazar and Prisman suggested the two-tiered treatment as a transitional approach.

Page 3 Q4 If question #3 above [directed to Lazar and Prisman] is confirmed, please explain why "suspect" data was used by your consultants as the basis for their report instead of the 2006 EDR data on file and reviewed by the Board.

A4 Board staff notes that the RRR data provided to Drs. Lazar and Prisman for their analysis is the same RRR data that, in "rolled up" form, underlies the data filed by electricity distributors in their 2006 distribution rate applications and reviewed by the Board. While individual numbers may be subject to some measurement and reporting errors, this RRR data is filed by distributors and was verified by the distributors in 2005 through a process undertaken by the Regulatory Audit office. As such, it is the best data currently available.

Q6 Please provide the RRR data used by your consultants in a format that maintains the confidentiality of the LDCs (i.e. redacted).

A6 The information provided to the consultants was from the information LDCs supply pursuant to the Board's Reporting and Record-Keeping Requirements (RRR). It is attached. The redacted fields are those that reflect information filed under the RRR on a confidential basis (trial balance of the Uniform System of Accounts under section 2.1.7 and labour information under section 2.1.5) and provided to Board staff's consultants also on a confidential basis.

Page 5 Q1 Please list and explain each and every way that a stratified deemed debt/equity structure could represent a barrier to amalgamation?

A1 One example would be where a larger LDC acquired a smaller one which had a higher equity component. It would be in the financial interest of the larger LDC to maintain the smaller LDC as a separate company. Amalgamation would result in a loss of income.

Another example would be where two smaller LDCs merge to form one larger LDC. There would also be a loss of income if the combined larger LDC moved into a different size category.

These examples assume that the new amalgamated LDC would seek after amalgamation to have new rates set by the Board. Such rates would be calculated based on a revenue requirement of the combined rate bases. This may result in a lower revenue requirement.

Q2 Please provide any evidence and/or concrete examples of differing deemed debt/equity structures acting as a barrier to amalgamation.

A2 Please see response to Bluewater Power, Page 5 - Q1.

Q3 Please explain how the objective of not creating barriers to amalgamation fits within the Board's mandate to set just and reasonable rates.

A3 In setting just and reasonable rates, the Board is not precluded from having regard to broader policy considerations.

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)	ASPHODEL NORWOOD DISTRIBUTION INC.	ATIKOKAN HYDRO INC.	ATTAWAPISKAT POWER CORPORATION	AURORA HYDRO CONNECTIONS LTD	BARRIE HYDRO DISTRIBUTION INC.	BLUEWATER POWER DISTRIBUTION CORP.	BRANT COUNTY POWER INC.	BRANTFORD POWER INC.	BURLINGTON HYDRO INC.	CAMBRIDGE AND NORTH DUMFRIES HYDRO INC.
Approved Regulatory Return Information										
2002 RUD Rate Base	502,176	2,647,326	N/A	28,804,790	108,021,367	42,469,525	12,710,337	46,980,726	95,757,217	75,714,622
Deemed Equity	50.00%	50.00%	N/A	50.00%	45.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Debt	50.00%	50.00%	N/A	50.00%	55.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.25%	7.25%	6.80%	7.25%	7.00%	7.25%	7.25%	7.25%	7.25%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	397,086	1,956,135		20,425,503	100,478,632	35,255,051	9,312,615	41,025,878	74,685,392	75,459,000
2003 Net Property Plant and Equipment	430,636	1,830,355	9,245	21,427,373	109,771,565	34,548,150	9,734,003	41,154,648	79,405,017	76,889,000
2004 Net Property Plant and Equipment	518,613	1,887,623	309,413	20,757,031	109,083,060	35,549,427	10,639,901	41,925,897	81,939,501	75,452,000
Retained Earnings										
2002 AFS Retained Earnings	(23,297)	245,084	N/A	1,409,077	856,038	2,989,938	(522,042)	554,349	3,668,702	4,506,000
2003 AFS Retained Earnings	(5,988)	(505,888)	(21,446)	1,629,814	7,369,077	5,312,920	332,060	1,089,410	7,172,882	8,477,000
2004 AFS Retained Earnings	(1,366)	(418,283)	102,957	1,990,957	10,531,501	5,976,405	1,048,104	1,490,962	8,414,922	10,909,000
Dividends										
2004 AFS Dividend	-	-	-	-	1,100,000	300,000	-	-	2,825,000	-
2003 AFS Dividend	-	-	-	-	-	-	-	-	3,575,000	-
2002 AFS Dividend	-	-	-	-	-	-	-	-	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	575	1,514	N/A	12,807	52,941	30,200	6,972	31,042	50,113	39,494
Residential Customers 2003	578	1,488	N/A	13,428	55,195	30,451	7,259	31,468	51,456	40,795
Residential Customers 2004	580	1,475	284	14,408	57,473	30,648	7,471	32,108	52,787	41,372
General Service Customers 2002	104	277	N/A	1,380	6,279	4,197	1,459	3,333	5,310	4,876
General Service Customers 2003	100	256	N/A	1,396	6,395	4,280	1,481	3,336	5,417	4,967
General Service Customers 2004	102	248	113	1,432	6,500	4,331	1,406	3,375	5,469	5,084
Large Use Customers 2002	0	23	N/A	-	0	5	1	0	0	3
Large Use Customers 2003	0	20	N/A	-	0	5	1	-	0	3
Large Use Customers 2004	0	22	-	-	0	5	1	-	-	3
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	12,691,624	48,452,299	N/A	404,580,973	1,338,636,805	1,142,049,563	242,175,761	906,997,411	1,648,001,699	1,450,044,760
kWh Consumed 2003	12,407,678									
kWh Consumed 2004	12,535,309	36,191,444	8,801,243	411,574,787	1,418,931,519	1,149,895,557	220,131,892	954,917,378	1,638,103,136	1,566,869,038
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	523,401	4,581,344	N/A	36,629,773	59,420,314	53,400,513	13,488,089	16,441,283	68,037,677	68,991,434
Distribution System Losses (kWh) 2003	530,984	371,561	N/A	40,382,376	67,503,366	39,896,734	11,546,616	32,471,288	69,981,248	65,766,413
Distribution System Losses (kWh) 2004	655,856	2,590,726	688,584	38,331,514	63,822,831	32,939,702	9,789,120	38,323,994	69,716,073	57,878,799
Location										
Rural?	No	No	No	No	Yes	Yes	Yes	No	Yes	Yes
Urban?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	11.8	92.5	9.8	372.2	1517	783.5	432	446	1383	1082
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)

	CENTRE WELLINGTON HYDRO LTD.	CHAPLEAU PUBLIC UTILITIES CORP.	CHATHAM KENT HYDRO INC.	CLINTON POWER CORPORATION	COLLUS POWER CORP	COOPERATIVE HYDRO EMBRUN INC.	DUTTON HYDRO LIMITED	Eastern Ontario Power (CNP)	E.L.K. ENERGY INC.	ENERSOURCE HYDRO MISSISSAUGA
Approved Regulatory Return Information										
2002 RUD Rate Base	8,553,726	1,609,408	45,653,588	1,400,263	13,535,678	1,505,986	405,154	3,157,217	11,068,045	451,388,902
Deemed Equity	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	40.00%
Deemed Debt	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	60.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	6.90%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	7,242,270	957,517	39,216,367		9,263,540	1,835,036	275,210		8,301,679	398,536,000
2003 Net Property Plant and Equipment	7,055,290	929,994	39,362,281	951,708	9,013,249	1,865,414	255,785	3,726,000	7,905,312	395,815,000
2004 Net Property Plant and Equipment	7,081,762	926,890	40,014,768	953,528	8,910,185	1,836,037	231,710	3,295,000	7,713,192	393,844,000
Retained Earnings										
2002 AFS Retained Earnings	1,230,150	(19,941)	2,844,886		(259,603)	196,667	(119,273)		3,623,826	21,529,000
2003 AFS Retained Earnings	1,560,568	(192,022)	3,745,215	58,555	5,824	290,522	(150,495)		5,698,273	31,502,000
2004 AFS Retained Earnings	1,889,894	(488,681)	4,726,800	79,343	217,573	383,927	(186,042)		6,986,379	16,250,000
Dividends										
2004 AFS Dividend	-	-	500,000	-	-	-	-	-	-	25,742,000
2003 AFS Dividend	-	-	475,000	-	-	-	-	-	-	-
2002 AFS Dividend	-	-	-	-	-	-	-	-	6,500,000	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	4,986	1,175	28,087	1,366	11,420	1,301	469	-	9,132	146,914
Residential Customers 2003	5,163	1,164	28,204	1,367	11,756	1,417	482	3,037	9,132	153,732
Residential Customers 2004	5,319	1,166	28,200	1,354	11,800	1,522	486	3,261	9,488	156,410
General Service Customers 2002	676	196	3,733	245	1,740	184	88	#N/A	1,134	19,698
General Service Customers 2003	670	182	3,715	246	1,639	184	87	475	1,020	20,120
General Service Customers 2004	683	182	3,670	251	1,657	185	86	463	1,036	20,453
Large Use Customers 2002	0	-	3	-	2	0	0	#N/A	-	10
Large Use Customers 2003	0	-	3	-	2	0	0	0	111	10
Large Use Customers 2004	0	-	2	-	2	0	-	0	-	8
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	152,849,099	33,581,386	907,648,364	30,918,632	354,595,657	25,472,898	7,800,635	N/A	186,236,990	7,582,464,082
kWh Consumed 2003										
kWh Consumed 2004	149,606,725	30,651,703	867,960,111	31,297,146	367,636,669	29,167,075	8,340,432	85,370,757	199,496,976	7,689,582,883
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	6,306,201	605,298	30,640,874	1,821,107	15,347,319	1,763,254	338,490	N/A	2,156,632	310,735,764
Distribution System Losses (kWh) 2003	6,091,991	1,153,247	37,629,589	1,738,022	11,432,137	1,498,355	336,857	3,429,836	5,102,209	241,907,672
Distribution System Losses (kWh) 2004	6,604,824	2,003,243	36,193,015	N/A	14,298,373	416,671	347,517	4,493,198	13,565,526	246,046,737
Location										
Rural?	No	No	No	No	No	No	No	Yes	No	No
Urban?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	140.3	27.5	745	21	320	28.1	7.6	142	136.1	11369
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)	ENWIN POWERLINES LTD	ERIE THAMES POWERLINES CORP.	ESPANOLA REGIONAL HYDRO DISTRIBUTION CORPORATION	ESSEX POWERLINES CORPORATION	FESTIVAL HYDRO INC.	FORT ALBANY POWER CORPORATION	Fort Erie (CNP)	FORT FRANCES POWER CORPORATION	GRAND VALLEY ENERGY INC.	GRAVENHURST HYDRO ELECTRIC INC.
Approved Regulatory Return Information										
2002 RUD Rate Base	161,325,087	16,104,265	2,668,643	28,722,176	31,136,775	N/A	21,170,240	4,894,305	550,846	8,718,402
Deemed Equity	45.00%	50.00%	50.00%	50.00%	50.00%	N/A	50.00%	50.00%	50.00%	50.00%
Deemed Debt	55.00%	50.00%	50.00%	50.00%	50.00%	N/A	50.00%	50.00%	50.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.00%	7.25%	7.25%	7.25%	7.25%	6.80%	7.25%	7.25%	7.25%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	149,421,219	13,263,547	2,011,333	23,023,901	27,325,837	17,748		3,813,210	369,917	7,130,234
2003 Net Property Plant and Equipment	149,521,330	14,260,170	2,085,317	23,103,769	27,632,957		26,955,000	3,567,772	356,796	7,128,513
2004 Net Property Plant and Equipment	148,718,020	14,877,793	1,994,918	22,946,597	28,175,014		31,567,000	3,389,922	363,897	7,067,737
Retained Earnings										
2002 AFS Retained Earnings	(2,441,072)	74,573	(221,598)	149,563	1,429,763	(369,834)		(11,662)	645,333	255,668
2003 AFS Retained Earnings	68,401	845,948	(62,879)	854,801	2,594,932			(64,616)		1,021,237
2004 AFS Retained Earnings	(4,685,143)	753,462	(187,386)	807,774	2,790,089			(93,894)		1,481,066
Dividends										
2004 AFS Dividend	-	-	-	300,000	1,025,957	-	-	-	-	-
2003 AFS Dividend	-	-	-	-	1,025,872	-	-	-	-	-
2002 AFS Dividend	-	-	-	-	305,000	-	-	-	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	72,501	11,856	2,853	24,213	16,064	208	13,846	3,319	583	5,097
Residential Customers 2003	73,872	11,895	2,853	24,600	16,253	214	13,492	3,321	583	5,139
Residential Customers 2004	75,107	12,075	2,843	24,909	16,463	181	14,280	3,583	591	5,189
General Service Customers 2002	8,222	1,547	472	2,072	2,302	75	1,316	499	89	690
General Service Customers 2003	8,250	1,569	472	2,134	2,233	86	1,378	466	83	698
General Service Customers 2004	8,310	1,573	455	2,158	2,220	81	1,431	474	89	704
Large Use Customers 2002	10	1	-	0	1	-	0	0	-	-
Large Use Customers 2003	10	1	-	0	1	-	0	-	6	-
Large Use Customers 2004	9	1	-	0	1	-	0	-	-	-
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	2,963,574,789	366,079,169	63,927,147	538,507,764	624,925,472	9,128,091	286,928,596	79,455,425	8,587,478	91,827,152
kWh Consumed 2003										
kWh Consumed 2004	2,647,727,977	408,997,604	64,638,104	531,403,805	632,340,069	8,582,311	286,529,694	82,412,827	9,225,189	91,791,284
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	79,045,901	7,909,829	1,626,640	23,505,468	13,775,211	116,979	18,314,591	3,088,359	963,675	6,575,660
Distribution System Losses (kWh) 2003	72,986,558	4,516,133	771,824	19,768,734	10,439,485	482,328	18,185,147	2,769,292	412,381	7,604,340
Distribution System Losses (kWh) 2004	88,540,359	5,180,691	384,376	25,560,128	16,968,472	381,011	18,289,129	3,052,839	517,623	8,950,283
Location										
Rural?	No	No	Yes	Yes	No	No	Yes	No	No	Yes
Urban?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	1184	258	136.2	462.9	274.9	10.6	487.6	84.6	8.1	246.2
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)

	GREAT LAKES POWER LIMITED - DISTRIBUTION	GREATER SUDBURY HYDRO INC.	GRIMSBY POWER INCORPORATED	GUELPH HYDRO ELECTRIC SYSTEM INC.	HALDIMAND COUNTY HYDRO INC.	HALTON HILLS HYDRO INC.	HAMILTON HYDRO INC.	HEARST POWER DISTRIBUTION COMPANY LIMITED	HYDRO 2000 INC.	HYDRO HAWKESBURY INC.
Approved Regulatory Return Information										
2002 RUD Rate Base	36,596,100	73,815,864	11,829,863	82,918,060	33,509,753	25,052,968	247,324,048	2,246,313	732,727	4,596,179
Deemed Equity	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	45.00%	50.00%	50.00%	50.00%
Deemed Debt	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	55.00%	50.00%	50.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.00%	7.25%	7.25%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	39,913,000	62,502,498	9,834,852	72,478,000	29,785,502	23,568,769	204,593,000	1,258,419	380,357	2,244,640
2003 Net Property Plant and Equipment	42,604,000	62,313,022	9,992,980	71,988,000	30,385,057	23,498,521	208,239,000	1,174,223	352,521	2,107,397
2004 Net Property Plant and Equipment	46,903,000	60,485,079	10,353,491	71,849,000	30,439,501	24,022,240	208,398,000	1,090,723	350,216	2,028,533
Retained Earnings										
2002 AFS Retained Earnings	20,664,000	(3,489,151)	559,688	7,297,000	3,115,573	233,887	17,315,000	2,180,207	190,657	(31,925)
2003 AFS Retained Earnings	21,452,000	(3,170,185)	1,119,202	10,902,000	2,706,070	1,404,876	22,106,000	2,182,437	314,877	585,108
2004 AFS Retained Earnings	21,991,000	(3,875,426)	1,533,444	14,143,000	2,840,547	2,394,782	29,559,000	2,223,412	418,548	625,383
Dividends										
2004 AFS Dividend	-	-	-	-	19,654	-	2,150,000	-	-	84,467
2003 AFS Dividend	-	-	-	-	500,652	-	2,250,000	-	-	-
2002 AFS Dividend	-	-	-	-	-	-	-	-	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	10,378	38,643	7,848	36,892	17,407	-	158,221	2,308	955	4,521
Residential Customers 2003	10,459	39,841	8,156	39,126	17,585	16,787	159,055	2,317	955	4,553
Residential Customers 2004	10,453	39,492	8,535	39,145	17,776	17,004	160,464	2,338	969	4,580
General Service Customers 2002	992	4,228	817	3,721	2,529	-	15,026	434	164	632
General Service Customers 2003	1,006	2,840	813	3,814	2,527	1,578	16,956	438	167	660
General Service Customers 2004	1,002	3,761	821	3,848	2,536	1,715	17,021	459	164	646
Large Use Customers 2002	2	-	-	3	0	-	10	-	0	1
Large Use Customers 2003	2	-	-	3	0	-	10	-	0	1
Large Use Customers 2004	2	-	-	4	-	-	10	-	-	1
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	125,925,257	841,692,200	158,666,749	1,468,479,033	386,268,293	422,232,661	5,303,642,768	119,108,138	25,609,211	198,637,486
kWh Consumed 2003										
kWh Consumed 2004	176,523,633	923,635,963	158,485,848	1,554,235,644	362,422,451	454,683,669	4,165,965,258	114,832,667	27,530,422	202,287,578
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	11,322,946	36,620,176	4,321,648	44,505,856	27,647,298	178,343,104	131,833,320	654,952	1,165,504	8,495,944
Distribution System Losses (kWh) 2003	18,336,971	44,967,303	2,969,647	28,293,505	24,964,530	16,299,861	132,690,315	3,109,836	1,780,915	9,649,738
Distribution System Losses (kWh) 2004	17,717,667	1,815,481	4,793,427	18,051,541	20,095,130	16,858,472	152,981,779	2,793,050	324,875	8,856,782
Location										
Rural?	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	No
Urban?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	1832.5	833.6	233.4	916	350	1301.1	2481	68.4	22.8	65.4
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)

	HYDRO ONE BRAMPTON NETWORKS INC.	HYDRO ONE NETWORKS INC.	HYDRO ONE REMOTE COMMUNITIES	HYDRO OTTAWA LIMITED	INNISFIL HYDRO DISTRIBUTION SYSTEMS LIMITED	KASCHEWAN POWER CORPORATION	KENORA HYDRO ELECTRICITY CORP LTD.	KINGSTON ELECTRICITY DISTRIBUTION LIMITED	KITCHENER-WILMOT HYDRO INC.	LAKEFIELD DISTRIBUTION INC.
Approved Regulatory Return Information										
2002 RUD Rate Base	211,672,968	3,053,000,000	N/A	386,493,612	20,162,592	N/A	6,138,558	24,210,042	139,931,166	1,514,121
Deemed Equity	45.00%	35.00%	35.00%	40.00%	50.00%	N/A	50.00%	50.00%	45.00%	50.00%
Deemed Debt	55.00%	65.00%	65.00%	60.00%	50.00%	N/A	50.00%	50.00%	55.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.00%	6.80%	6.80%	6.90%	7.25%	6.80%	7.25%	7.25%	7.00%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	204,252,000	2,927,000,000	23,245,000	320,196,000	17,935,545		5,139,293	25,714,037	124,183,068	1,323,284
2003 Net Property Plant and Equipment	208,717,000	3,088,000,000	23,666,000	352,701,000	17,167,869	141,008	5,061,619	25,743,429	124,912,415	1,362,278
2004 Net Property Plant and Equipment	211,126,000	3,226,000,000	23,752,000	383,162,000	16,729,066	122,118	4,959,560	20,702,239	129,224,134	1,513,856
Retained Earnings										
2002 AFS Retained Earnings	13,166,000		(637,000)	(26,036,000)	79,075		(129,245)	610,782	7,382,142	(4,629)
2003 AFS Retained Earnings	16,228,000		-	(24,821,000)	579,820	21,947	(6,189)	969,534	11,449,841	165,408
2004 AFS Retained Earnings	18,284,000		-	(8,205,000)	759,273	(65,912)	(87,943)	982,998	14,797,363	237,869
Dividends										
2004 AFS Dividend	9,000,000	-	-	-	238,000	-	-	-	542,005	50,000
2003 AFS Dividend	11,000,000	-	-	-	200,000	-	-	-	-	-
2002 AFS Dividend	2,800,000	-	-	(2,207,000)	-	-	-	-	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	88,414	1,005,912	-	237,755	12,227	238	5,186	22,574	65,683	1,146
Residential Customers 2003	95,064	1,021,476	#N/A	242,369	12,409	240	4,834	22,517	67,527	1,151
Residential Customers 2004	102,070	1,031,758	-	247,790	12,670	243	4,980	22,712	69,405	1,164
General Service Customers 2002	7,984	106,576	#N/A	26,754	918	50	805	3,880	7,637	229
General Service Customers 2003	8,136	106,613	#N/A	26,810	953	53	793	3,838	7,738	203
General Service Customers 2004	8,364	107,819	#N/A	26,225	962	54	854	3,762	7,874	214
Large Use Customers 2002	4	27	#N/A	11	-	-	-	4	4	0
Large Use Customers 2003	4	25	#N/A	11	-	-	-	3	4	0
Large Use Customers 2004	3	25	#N/A	10	-	-	-	3	4	0
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	3,418,980,431	21,799,050,000	N/A	7,470,558,035	199,552,665	7,058,464	111,208,080	733,454,031	1,966,638,124	31,750,150
kWh Consumed 2003										
kWh Consumed 2004	3,483,144,427	23,112,070,000	N/A	7,514,934,346	217,001,539	8,258,631	107,420,407	718,541,335	1,947,739,693	32,085,091
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	19,595,896	1,715,950,000	N/A	267,268,519	21,661,933	345,759	3,746,582	9,158,405	71,774,528	731,582
Distribution System Losses (kWh) 2003	98,024,459	1,671,250,000	N/A	271,898,675	12,626,157	497,309	3,966,510	33,079,007	42,826,561	1,229,980
Distribution System Losses (kWh) 2004	116,374,379	1,718,440,000	N/A	187,083,341	8,461,717	497,309	4,568,438	30,107,145	62,192,640	1,098,804
Location										
Rural?	No	Yes	N/A	Yes	Yes	No	No	No	Yes	No
Urban?	Yes	No	N/A	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	2384	119040		5040	596	6.2	98	454	1758	28
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)	LAKEFRONT UTILITIES INC.	LAKELAND POWER DISTRIBUTION LTD	LONDON HYDRO INC.	MIDDLESEX POWER DISTRIBUTION CORPORATION	MIDLAND POWER UTILITY CORPORATION	MILTON HYDRO DISTRIBUTION INC.	NEWBURY POWER	NEWMARKET HYDRO LIMITED	NIAGARA FALLS HYDRO INC.	NIAGARA-ON-THE-LAKE HYDRO INC.
Approved Regulatory Return Information										
2002 RUD Rate Base	13,988,892	15,408,892	174,041,606	10,288,429	8,211,325	29,868,419	176,296	49,063,827	54,089,445	13,859,589
Deemed Equity	50.00%	50.00%	45.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Debt	50.00%	50.00%	55.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.25%	7.25%	7.00%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment		12,259,565	161,375,000	8,329,585	5,434,226	25,616,002	179,688	36,537,525	50,236,990	13,457,402
2003 Net Property Plant and Equipment	9,982,107	12,495,147	163,874,000	8,072,027	5,114,315	27,054,474	168,697	36,627,179	53,729,279	16,451,062
2004 Net Property Plant and Equipment	9,830,870	12,444,235	166,252,000	7,832,122	5,172,341	28,936,859	163,826	38,398,426	60,145,961	16,618,706
Retained Earnings										
2002 AFS Retained Earnings		379,566	8,394,000	(1,150,042)	(209,363)	1,224,936	(18,989)	335,833	6,779,002	248,928
2003 AFS Retained Earnings	1,653,460	1,430,955	13,325,000	(1,419,238)	311,258	2,750,489	(24,543)	777,151	7,757,374	675,441
2004 AFS Retained Earnings	1,657,792	2,455,358	21,433,000	(1,296,658)	767,748	4,235,704	(33,835)	1,579,215	8,890,588	578,460
Dividends										
2004 AFS Dividend	800,000	-	-	-	300,000	-	-	-	-	-
2003 AFS Dividend	-	-	-	-	-	-	-	-	-	-
2002 AFS Dividend	-	-	-	-	-	-	-	-	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	7,339	7,147	119,454	5,823	5,358	12,043	189	20,963	29,126	5,507
Residential Customers 2003	7,438	7,251	121,139	5,879	5,533	14,053	N/A	21,696	29,554	5,661
Residential Customers 2004	7,494	7,300	123,095	5,985	5,568	15,060	160	22,691	31,250	5,902
General Service Customers 2002	1,100	1,631	13,213	778	775	2,047	N/A	2,846	3,573	1,347
General Service Customers 2003	1,101	1,620	13,245	773	830	2,116	N/A	2,630	4,094	1,349
General Service Customers 2004	1,140	1,636	13,389	778	855	2,137	29	2,966	4,128	1,355
Large Use Customers 2002	-	0	3	1	-	2	N/A	-	0	0
Large Use Customers 2003	0	-	3	1	-	2	N/A	0	-	0
Large Use Customers 2004	0	-	3	1	-	2	-	0	-	0
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	273,174,215	216,469,552	3,338,203,398	171,112,472	219,942,839	563,774,417	N/A	638,870,171	793,012,818	169,174,548
kWh Consumed 2003										
kWh Consumed 2004	276,130,945	220,065,577	3,383,633,950	159,788,760	227,207,629	590,836,869	3,764,925	661,514,842	818,506,340	168,165,203
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	12,842,134	18,462,083	58,311,262	10,059,060	7,037,974	19,328,539	N/A	23,028,828	14,273,225	7,745,585
Distribution System Losses (kWh) 2003	12,477,891	7,864,784	12,000	8,004,160	7,528,241	18,611,920	N/A	22,477,824	39,958,139	7,549,523
Distribution System Losses (kWh) 2004	19,261,734	7,453,214	595,654	10,437,029	6,450,826	19,751,271	219,364	23,942,073	42,726,030	9,987,202
Location										
Rural?	No	Yes	Yes	No	Yes	Yes	Yes	No	No	Yes
Urban?	Yes	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	100	659	2498	108	112	730	4	627.5	791	327
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)	NORFOLK POWER DISTRIBUTION INC.	NORTH BAY HYDRO DISTRIBUTION LTD.	NORTHERN ONTARIO WIRES	OAKVILLE HYDRO ELECTRIC DISTRIBUTION INC.	ORANGEVILLE HYDRO LIMITED	ORILLIA POWER DISTRIBUTION CORPORATION	OSHAWA PUC NETWORKS INC.	OTTAWA RIVER POWER CORPORATION	PARRY SOUND POWER CORPORATION	PENINSULA WEST UTILITIES LIMITED
Approved Regulatory Return Information										
2002 RUD Rate Base	28,259,040	38,665,209	6,229,522	111,346,108	14,146,982	17,894,048	52,062,025	11,031,329	6,561,667	24,354,447
Deemed Equity	50.00%	50.00%	50.00%	45.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Debt	50.00%	50.00%	50.00%	55.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.25%	7.25%	7.25%	7.00%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	29,860,974	54,838,938	4,325,284	113,559,000	11,869,631	14,445,000	36,746,000		4,778,029	19,173,129
2003 Net Property Plant and Equipment	31,046,528	30,798,113	4,027,006	109,934,000	12,754,400	14,362,000	38,584,000		4,602,885	
2004 Net Property Plant and Equipment	36,268,394	29,410,003	3,776,924	107,466,000	12,757,436	14,919,000	42,158,000		4,594,146	
Retained Earnings										
2002 AFS Retained Earnings	(167,017)	(1,669,626)	(1,060,239)	2,316,000	1,275,170	921,000	789,000		(14,377)	632,770
2003 AFS Retained Earnings	(248,721)	611,899	(1,019,195)	7,758,000	1,315,787	1,205,000	3,986,000		167,989	
2004 AFS Retained Earnings	(11,139)	1,032,036	(1,165,780)	9,128,000	1,374,105	829,000	6,055,000		282,447	
Dividends										
2004 AFS Dividend	200,000	-	-	-	513,000	2,000,000	(1,000,000)	-	-	-
2003 AFS Dividend	50,000	-	-	-	513,000	940,000	(525,000)	-	-	-
2002 AFS Dividend	-	-	-	-	-	400,000	-	-	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	15,187	20,193	5,403	44,251	8,398	10,538	42,960	8,421	2,607	12,476
Residential Customers 2003	15,444	20,612	5,359	46,167	8,581	10,651	43,679	8,439	2,570	12,413
Residential Customers 2004	15,686	20,364	5,268	47,496	8,801	10,743	44,280	8,501	2,594	12,618
General Service Customers 2002	2,329	3,075	970	5,606	1,016	1,568	4,570	1,590	620	1,712
General Service Customers 2003	2,192	2,991	965	5,645	1,035	1,607	4,515	1,593	621	1,723
General Service Customers 2004	2,281	3,150	964	5,732	1,043	1,505	4,393	1,607	636	1,733
Large Use Customers 2002	0	0	0	3	0	-	2	-	-	-
Large Use Customers 2003	0	-	-	2	-	-	2	-	-	-
Large Use Customers 2004	0	0	-	2	-	-	3	-	-	-
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	352,413,171	583,444,622	142,682,627	1,741,956,882	226,673,621	317,673,033	1,235,943,760	191,317,428	74,567,370	327,821,015
kWh Consumed 2003										
kWh Consumed 2004	350,785,542	590,330,329	124,118,006	1,658,990,490	233,274,463	317,099,431	1,129,177,382	204,676,301	84,098,646	339,148,264
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	24,439,233	10,131,158	2,298,461	82,400,670	8,690,869	10,085,822	N/A	13,615,417	11,581,884	25,443,707
Distribution System Losses (kWh) 2003	18,935,589	7,460,223	5,424,375	66,114,143	6,264,713	12,452,902	N/A	4,909,144	1,000,628	16,429,979
Distribution System Losses (kWh) 2004	20,961,861	8,482,806	16,509,631	56,546,590	6,434,086	12,483,626	49,263,808	4,845,757	3,439,511	13,091,494
Location										
Rural?	Yes	Yes	No	Yes	No	No	Yes	No	No	Yes
Urban?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	770	560	370	1316	236	297.7	1588.8	147.4	128	1300
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)	PETERBOROUGH DISTRIBUTION INC	Port Colborne (CNP)	POWERSTREAM INC.	PUC DISTRIBUTION INC.	RENFREW HYDRO INC.	RIDEAU ST. LAWRENCE DISTRIBUTION INC.	SCUGOG HYDRO ENERGY CORPORATION	SIOUX LOOKOUT HYDRO INC.	ST. CATHERINES HYDRO UTILITY SERVICES INC.	ST. THOMAS ENERGY INC.
Approved Regulatory Return Information										
2002 RUD Rate Base	44,725,919	10,728,020	334,439,260	45,747,269	4,958,520	4,793,601	2,000,887	5,588,188	64,127,964	19,293,900
Deemed Equity	50.00%	50.00%	40.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Debt	50.00%	50.00%	60.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.25%	7.25%	6.90%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	39,310,671			35,822,410	4,151,923	3,191,433	1,597,937	4,900,029	55,027,061	16,651,726
2003 Net Property Plant and Equipment	39,748,119	4,409,000		34,976,660	3,994,483	3,208,083	1,542,282	4,914,951	55,671,440	17,446,149
2004 Net Property Plant and Equipment	40,372,342	6,074,000		34,868,716	4,027,825	3,427,116	1,485,635	4,920,343	56,619,951	17,626,938
Retained Earnings										
2002 AFS Retained Earnings	865,922			9,906	37,865	123,459	(619,483)	362,292	10,550,136	614,758
2003 AFS Retained Earnings	2,575,940			1,273,536	39,793	322,834	(701,888)	538,173	12,841,721	1,168,448
2004 AFS Retained Earnings	3,352,192			(113,545)	95,951	595,062	(316,306)	482,624	15,373,896	2,065,576
Dividends										
2004 AFS Dividend	1,318,683	-	-	-	-	57,000	-	132,538	-	-
2003 AFS Dividend	818,683	-	-	-	-	57,000	-	132,538	76,850	-
2002 AFS Dividend	-	-	-	-	-	-	-	88,359	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	26,633	8,066	157,514	28,526	3,440	4,856	1,942	2,279	46,098	12,666
Residential Customers 2003	27,091	8,071	166,230	28,709	3,471	4,860	1,955	2,274	46,372	12,874
Residential Customers 2004	27,496	8,128	172,636	28,569	3,472	4,869	1,974	2,287	46,724	13,182
General Service Customers 2002	4,161	1,133	23,445	3,714	544	857	352	450	5,207	1,728
General Service Customers 2003	3,722	1,200	23,966	3,734	577	878	363	461	5,237	1,738
General Service Customers 2004	3,880	1,205	24,500	3,796	578	880	366	462	5,251	1,748
Large Use Customers 2002	2	0	5	-	-	0	-	-	4	1
Large Use Customers 2003	2	0	5	-	0	-	-	-	4	1
Large Use Customers 2004	2	0	5	-	-	-	-	-	4	1
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	757,382,137	145,862,401	5,733,481,044	714,673,993	92,806,876	122,481,365	48,849,919	90,462,537	1,412,449,614	362,208,340
kWh Consumed 2003										
kWh Consumed 2004	745,571,055	180,920,536	6,019,556,899	723,592,739	92,881,382	125,748,798	49,750,554	91,105,525	1,328,039,102	368,821,506
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	22,524,647	7,676,968	207,911,415	31,605,217	4,366,413	6,592,850	2,685,233	5,300,280	42,184,386	2,238,470
Distribution System Losses (kWh) 2003	16,009,841	9,829,387	192,949,268	28,342,080	4,926,626	9,441,762	3,462,208	5,674,113	39,564,714	737,908
Distribution System Losses (kWh) 2004	26,551,933	9,522,133	182,266,496	30,377,732	5,637,118	10,310,815	3,414,078	6,965,216	39,663,384	1,042,917
Location										
Rural?	No	Yes	Yes	Yes	No	Yes	No	Yes	Yes	No
Urban?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	494	271	5379	711	70	86	32.8	212	722	233
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted

From information provided by each distributor under the OEB's Reporting and Record Keeping Requirements (includes audited financial statements, trial balance in accordance with the Uniform System of Accounts and other statistical information)	TAY HYDRO ELECTRIC DISTRIBUTION COMPANY INC.	TERRACE BAY SUPERIOR WIRES INC.	THUNDER BAY HYDRO ELECTRICITY DISTRIBUTION INC.	TILLSONBURG HYDRO INC.	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED	VERIDIAN CORPORATION	WASAGA DISTRIBUTION INC.	WATERLOO NORTH HYDRO INC.	WELLAND HYDRO-ELECTRIC SYSTEM CORP.	WELLINGTON ELECTRIC DISTRIBUTION COMPANY INC.
Approved Regulatory Return Information										
2002 RUD Rate Base	4,077,253	1,622,915	66,420,856	8,683,112	1,810,112,668	144,971,438	9,291,089	80,367,575	24,269,440	1,584,985
Deemed Equity	50.00%	50.00%	50.00%	50.00%	35.00%	45.00%	50.00%	50.00%	50.00%	50.00%
Deemed Debt	50.00%	50.00%	50.00%	50.00%	65.00%	55.00%	50.00%	50.00%	50.00%	50.00%
Deemed Equity Rate	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%	9.88%
Deemed Debt Rate	7.25%	7.25%	7.25%	7.25%	6.80%	7.00%	7.25%	7.25%	7.25%	7.25%
From Audited Financial Statements										
Property Plant and Equipment										
2002 Net Property Plant and Equipment	3,186,828			5,510,361	1,546,588,000	111,440,013	14,920,432	83,650,163	19,245,829	1,063,000
2003 Net Property Plant and Equipment	3,016,030	1,326,094	59,173,077	5,774,734	1,537,399,000	109,085,965	15,449,286	82,066,083	18,561,973	1,018,000
2004 Net Property Plant and Equipment	2,899,933	1,244,047	59,685,870	5,338,170	1,518,186,000	106,990,573	16,567,683	83,801,434	18,703,497	1,055,000
Retained Earnings										
2002 AFS Retained Earnings	(153,625)	(43,889)	838,980	478,939	70,189,000	(2,337,094)	(18)	7,553,330	1,111,583	(9,000)
2003 AFS Retained Earnings	28,637	(14,671)	1,529,654	429,285	155,539,000	(2,013,735)	690,869	9,877,896	(308,492)	25,000
2004 AFS Retained Earnings	135,657	44,966	1,908,324	395,002	166,474,000	585,779	1,013,665	12,900,152	239,277	(39,000)
Dividends										
2004 AFS Dividend	-	-	-	-	49,200,000	-	-	-	(2,500)	-
2003 AFS Dividend	-	-	-	-	5,000,000	-	-	-	-	-
2002 AFS Dividend	132,000	-	-	-	-	-	-	-	-	-
Reported Statistical Information (RRR 2.1.5)										
# of Customers										
ResidentialCustomers 2002	3,598	836	43,688	5,338	586,714	80,271	8,534	38,624	18,768	1,071
Residential Customers 2003	3,622	838	44,110	5,420	590,109	82,018	8,843	39,847	19,007	1,159
Residential Customers 2004	3,648	838	44,167	5,523	594,976	84,662	9,329	41,215	19,142	1,411
General Service Customers 2002	306	112	5,129	737	78,283	8,773	845	5,632	2,215	130
General Service Customers 2003	287	112	5,123	745	78,469	8,846	848	5,635	2,145	127
General Service Customers 2004	289	112	5,153	740	78,149	8,968	779	5,664	2,094	148
Large Use Customers 2002	0	0	3	0	46	3	-	2	2	0
Large Use Customers 2003	0	0	3	-	47	3	0	2	3	-
Large Use Customers 2004	0	-	3	-	47	4	-	2	3	-
kWh Consumed (not including Dist'n System Losses)										
kWh Consumed 2002	42,328,700	19,012,531	1,035,885,591	217,790,206	26,177,019,147	2,281,971,130	93,651,360	1,251,191,402	491,264,776	14,444,113
kWh Consumed 2003										
kWh Consumed 2004	41,690,161	19,503,404	1,041,945,675	70,581,368	25,558,066,373	2,277,933,600	99,506,596	1,243,491,867	489,398,304	16,114,195
Distribution System Losses (kWh)										
Distribution System Losses (kWh) 2002	3,611,007	952,693	40,459,516	10,213,434	893,361,160	103,107,148	7,796,103	41,909,726	31,396,753	1,144,589
Distribution System Losses (kWh) 2003	3,840,898	606,627	41,842,871	10,941,598	912,532,285	108,370,514	5,536,311	55,438,844	30,633,401	940,850
Distribution System Losses (kWh) 2004	4,492,409	642,611	39,358,215	11,199,490	859,078,486	113,386,735	5,561,546	59,303,571	11,787,126	455,993
Location										
Rural?	Yes	No	Yes	Yes	No	Yes	Yes	Yes	No	No
Urban?	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Number of Employees	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted
Total line (km)	357.3	20.4	1338.1	231	16869	1510	208	1324.2	417.7	32.4
2.1.7 Trial Balance: USoA Accounts										
All trial balance accounts	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted	Redacted