Exhibit K 6.10

EB-2007-0681

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity.

DOCUMENT BRIEF

BOARD STAFF CROSS-EXAMINATION
PANEL #4
RE: DEFERRAL AND VARIANCE ACCOUNTS
ISSUES 6.1 AND 6.2

JULY 18, 2008

Deferral and Variance Accounts Issues 6.1 and 6.2

RP-2004-0117
RP-2004-0118
RP-2004-0100
RP-2004-0069
RP-2004-0064

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

AND IN THE MATTER OF an Application by Hydro One Networks Inc, Toronto Hydro-Electric System Limited, Enersource Hydro Mississauga Inc., and London Hydro Inc for an order or orders approving or fixing just and reasonable rates pertaining to the Recovery of Regulatory Assets - Phase 2.

BEFORE: Paul Vlahos
Presiding Member

Jan Carr
Vice Chair and Member

Cynthia Chaplin
Member

DECISION WITH REASONS

December 09, 2004

2.0.24 A number of inconsistencies were identified during the proceeding which must be addressed by the Applicants. While Enersource used the accrual approach, it appears to have used the billed approach in determining interest costs. As stated earlier, in the case of Toronto Hydro, the recording of revenues from Legacy Rates is not consistent with the accrual method it otherwise used. In the case of London Hydro, which uses the billed method, it accrued load transfers from Hydro One. The Board expects each distributor to adhere to its chosen method of accounting and reflect this in its refiling.

Line Loss Variances: All Applicants

2.0.25 ECMI noted that Toronto Hydro, Enersource and London Hydro have identified the specific losses and unaccounted for variances in Account 1588 and Account 1571 (Pre-Market Opening Energy Variance). ECMI noted that Hydro One, on the other hand, did not "trap" the loss factor variances in Account 1588, and as a result the Board has no way of knowing if Hydro One has overcharged its customers for commodity costs. ECMI suggested that the Board order Hydro One to report these amounts in Account 1588 (as opposed to reporting them in an unbilled revenue account), rather than wait until the amounts become material enough for Hydro One to seek recovery.

2.0.26 Hydro One disagreed with ECMI, maintaining that there was no examination undertaken on the mechanics of determining actual losses for the other three Applicants and that actual losses were not the subject of this proceeding.

Board Findings

2.0.27 Toronto Hydro, London Hydro, and Enersource recorded variances between the Board-approved distribution losses and actual losses in RSVA-Power Account 1588. Hydro One did not record any variances. We find that there should be a standardized approach for reporting variances in line losses in Account 1588, as stipulated in APH490. The recording and tracking of variances in line losses in Account 1588 will have the benefit of enhancing visibility and awareness of these losses for management, stakeholders and the Board. We accept that Hydro One does not have information on actual distribution losses for 2002 and 2003. However, in future, the Board directs Hydro One to include line loss variances in Account 1588, consistent with the other three Applicants and APH490.

Carrying Costs: Hydro One

2.0.28 VECC recommended that the Board order Hydro One to re-calculate the carrying costs associated with the RSVAs using the annual debt rate of 6.8% as outlined in the DRH, instead of its embedded cost of debt which ranged from 7.14% to 8.3%. This was rejected by Hydro One arguing that it makes no sense for a distributor to use a proxy rate when a real rate exists. Hydro One argued that the deemed debt rate in the DRH is for utilities that do not have actual debt.

Board Findings

2.0.29 There needs to be consistency in the interest rate applied to the RSVAs and all other relevant regulatory asset accounts. The rate of interest should be the rate that is reflected in the currently-approved rates for a distributor. We note that Toronto Hydro, Enersource, and London Hydro used their deemed debt rate in calculating carrying charges stipulated in the Rate Handbook. We accept the use of such rates since they are reflected in the Board-authorized rates for these Applicants. We do not accept that Hydro One should use the 6.8% stipulated in the Rate Handbook, as argued by some parties, because this is not the debt rate that underpins Hydro One's current rates. For the same reason, we do not accept Hydro One's use of its embedded cost of debt as it changes from time to time. The Board-approved debt rate that underpins Hydro One's current rates is the 7.71% debt rate agreed to by the parties, and accepted by the Board, in the March 11, 2002 Settlement Conference regarding proceeding RP-2000-0023/EB-2001-0016. The Board therefore directs Hydro One to use the 7.71% rate to recalculate interest in all of its deferral accounts.

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Pollution Probe (PP) INTERROGATORY #25 List 1

Interrogatory

Issue Number: 6.1
Issue: Is the proposal for the amounts, disposition and continuance of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate?

Ref. A/Tab 15/Sch 3- Attachment A- page 26

Are the variances between Hydro One's forecasted and actual electricity system losses recorded in a variance or deferral account?

Response

Hydro One uses the accrual method to record and report its financial results, and assumes that actual losses are the same as the OEB approved Distribution losses. Therefore, no variation exists between approved and actual losses, and consequently there is no variance or deferral account that would record the variation.

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Accounting for Specific Items

Retail Services and Settlement Variances

Table of Contents

c) Power Charges

i) $RSVA_{Power}$: The Retail Settlement Variance Account used to record net differences between the initial and final bills from the IESO (or a host distributor).

ii) $RSVA_{Power}$: Sub-account used to record the Global Adjustment/ Provincial Benefit net differences between the initial and final bills from the IESO (or a host distributor).

d) Other Recoveries and Charges

i) SSS Administration
ii) Distribution Wheeling Service
iii) Debt Retirement Charge
iv) Rural Rate Assistance

Purpose and Scope

Chapters 11 of the 2000 Electricity Distribution Rate Handbook make reference to variance accounts used to capture revenue and expense flows related to specific transactions. Generally, the variance accounts deal with the costs of certain Independent Electricity System Operator ("IESO")/ host distributor charges and their recovery from customers (includes the cost of the energy itself) as well as expenses and revenues relating to the provisions of retail services by the distributor.

Accordingly, the purpose of this Article is to:

- Provide additional guidance relating to accounting for the variance accounts (and the related revenues and expense streams) mentioned in Chapter 11 of the 2000 Electricity Distribution Rate Handbook and arising out of the requirements of the Retail Settlement Code.
- Provide additional guidance relating to accounting for various other recoveries and charges mentioned in Chapter 11 of the 2000 Electricity Distribution Rate Handbook.

charged by the Independent Electricity System Operator (based on the settlement invoice) for retail transmission network services.

This account may include monthly accruals for amounts not yet invoiced by the IESO, host distributor or embedded generator. The distributor must ensure a proper matching of the billed amounts recorded in Account 4066 to those charges recorded in this account.

If applicable, embedded distributors shall also establish and use this account to record the amount charged by the host distributor (based on the settlement invoice) for retail transmission network services.

- account 4716, Charges - CN. This account is to be used by distributors deemed by the Board to be transmission customers to record the amount charged by the Independent Electricity System Operator (based on the settlement invoice) for retail transmission connection service.

  This account may include monthly accruals for amounts not yet invoiced by the IESO, host distributor or embedded generator. The distributor must ensure a proper matching of the billed amounts recorded in Account 4068 to those charges recorded in this account.

  If applicable, embedded distributors shall also establish and use this account to record the amount charged by the host distributor (based on the settlement invoice) for retail transmission connection services.

c) Power Charges

i) Retail Settlement Variance Account for Power ($RSVA_{Power}$)

The $RSVA_{Power}$ account is established for the purpose of recording the "net difference" in energy cost only. "Net difference" refers to the difference between the amount charged by the IESO, host distributor or embedded generator based on the settlement invoice for the energy cost and the amount billed to customers for the energy cost. Note that these differences could be composed of differences in energy price and/ or energy quantities as well as the difference between estimated and actual line loss factors.

As indicated in Section b) above, a distributor may elect to use the accrual method for all RSVAs. With respect to $RSVA_{Power}$ account, a distributor may include accruals for monthly unbilled estimates in Sales of Electricity and monthly accruals for amounts not yet invoiced by the IESO, host distributor or embedded generator for Power Purchased. The distributor must ensure a proper matching of the billed amounts recorded in the electricity sales accounts to those charges recorded in Account 4705.

For the purposes of the $RSVA_{Power}$, it is important to note that under either the billed or accrual method all components of energy differences shall be recognized and recorded in this account. These components include price and quantity differences (e.g. using the IESO preliminary data compared to the monthly settlement invoices for billing) and the difference between the Board-approved historic loss factor and the actual loss experienced by the distributor.

Mechanics
The amounts to be posted to the $RSVA_{Power}$ are determined by comparing the energy cost on the settlement invoice to the energy cost billed to customers.

Recording practices similar to those listed for the RSVA mentioned earlier in this Article apply to the $RSVA_{Power}$ account (see pages 10 to 13).

Maintenance and recording
Similar to practices for the other RSVA mentioned earlier in this Article. See page 13.

Carrying Charges
Similar to those for other RSVA mentioned earlier in this Article. See page 13.

Disposition
Instructions specifically related to $RSVA_{Power}$ are discussed on page 13 to 15 of this Article or as otherwise specified by the Board.

Monitoring Requirements
Similar to those for other RSVA mentioned earlier in this Article. See page 11.

Account
The following account will be used for the purposes of recording the $RSVA_{Power}$ variance:

- Account 1588, $RSVA_{Power}$.

This account shall be used to record the net difference between:

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Ontario Energy Board (Board Staff) INTERROGATORY #121 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1
Hydro One is requesting to dispose of the RSVA Provincial Benefit account.

a. Please confirm that this refers to account 1588 sub-account Global Adjustment according to the USoA. If it is not, then please identify in which account this is being tracked.
b. Is Hydro One proposing to clear only the sub-account and not clear the entire balance in account 1588 RSVA Power?

Response

a. Yes, the RSVA Provincial Benefit account that Hydro One Distribution is requesting disposition of refers to the account 1588 sub-account Global Adjustment.

b. Yes, Hydro One Distribution is proposing to clear only the sub-account. Hydro One Distribution does not have RSVA for Power.

REGULATORY ASSETS

1.0 INTRODUCTION

The purpose of this evidence is to provide a description of the Distribution Regulatory Assets and a detailed account of their balances.

All of the Regulatory Assets reported by Hydro One Distribution have been established consistent with the Board's requirements as set out in the Accounting Procedures Handbook, subsequent Board direction, or per specific requests initiated by Hydro One Distribution.

The Distribution Regulatory Asset balances are summarized in Table 1 below:

Table 1
Distribution
Summary of Regulatory Asset Balances for Approval
$ million

Description	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Total Regulatory Assets for Approval	**8.4**	**(1.7)**	**(30.0)**	**(48.7)**

Hydro One Distribution is forecasting Regulatory Asset values up to April 30, 2008. It is expected that new Distribution rates will be implemented at the start of May 2008. Details on the forecast basis will be described for each account.

Disposition of the following accounts is discussed in Exhibit F1, Tab 2, Schedule 1.

2.0 REGULATORY ASSETS REQUESTED FOR APPROVAL

The following table provides a summary of the Regulatory Asset requested for approval:

Table 2
Distribution
Regulatory Assets Requested for Approval
$ million

Description	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
OEB Costs Account	(0.8)	(0.9)	(0.9)	(0.9)
Tax Changes Account	0.0	(2.8)	(4.7)	(5.0)
Smart Meter Minimum Functionality Under-recovery to May 31, 2007	0	3.6	5.8	6.9
Smart Meter Exceeding Minimum Functionality Under-recovery	0	0.6	3.4	5.7
Smart Meter Minimum Functionality Under-recovery between June 1, 2007 and April 30, 2008	0	0.0	3.7	9.4
Retail Settlement Variance Accounts	9.2	(2.2)	(37.3)	(64.8)
Total Regulatory Assets for Approval	**8.4**	**(1.7)**	**(30.0)**	**(48.7)**

In the Board's December 9, 2004 *Decision with Reasons* in the Review and Recovery of Regulatory Assets Phase 2 (RP-2004-0117/0118), Hydro One was directed to use a fixed rate of 7.71% for all Regulatory Asset accounts. Accordingly, simple interest at 7.71% was applied to the monthly opening principal balance in these accounts from May 1, 2006 to November 30, 2006.

In a letter dated November 28, 2006, the Board directed Electricity LDC's to implement a new prescribed interest rate. This new rate was to be effective May 1, 2006. On December 12, 2006 Hydro One wrote to the Board saying that Hydro One would be implementing this new interest rate effective December 1, 2006 since retroactive application of the interest rates could result in financial impacts different from those included in Hydro One's previously published financial statements. Accordingly, the interest rate for these accounts was changed to 4.59% (the OEB prescribed rate effective at that time) effective December 1, 2006. Hydro One has applied the OEB prescribed rate of 4.59% since December 1, 2006 for all Regulatory Asset accounts.

2.1 Ontario Energy Board Costs Account

In a letter dated December 20, 2004 the Board announced an amendment to the Accounting Procedures Handbook and the Uniform System of Accounts to establish a deferral account to record Ontario Energy Board Cost Assessments.

The intent of this account was to record Ontario Energy Board cost assessments incremental to the 1999 base year for the Board's fiscal year 2004 and subsequent fiscal year(s) determined in accordance with the following Board requirements.

In the Board's April 12, 2006 Decision with Reasons (RP-2005-0020 / EB-2005-0378) regarding Hydro One's 2006 Distribution Rates, the Board approved Hydro One Distributions OEB Costs Deferral Account amounts as submitted. Those amounts were forecast to April 30, 2006 based on the 2005/2006 OEB Q2 Invoice to Hydro One Distribution.

The 2005/2006 OEB Q3 and Q4 Invoices to Hydro One Distribution were lower than the 2005/2006 OEB Q2 Invoice, therefore the amount approved for recovery in the Board's April 12, 2006 Decision with Reasons was higher than the actual value in the OEB Costs Regulatory Asset account on May 1, 2006.

Hydro One Distribution transferred the approved value of the account into the Regulatory Asset Recovery account on May 1, 2006 leaving the excess of the approved amount over

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the actual amount as a credit in the OEB Costs Regulatory Asset account. No additional principal amounts have been added to this account since May 1, 2006.

Table 3 provides a summary of Ontario Energy Board Cost Assessments related deferral balances for the Hydro One Distribution business:

Table 3
Distribution
OEB Costs Deferral Account Balances
$ million

Description	USofA Account Ref	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
OEB Costs Account	1508	(0.8)	(0.9)	(0.9)	(0.9)

After approval by the Board, this account will be closed.

2.2 Tax Changes Account

In the Board communique of December 2005 (to LDC's), and the Board's April 12, 2006 Decision with Reasons (RP-2005-0020 / EB-2005-0378) regarding Hydro One's 2006 Distribution Rates, the Board authorized the creation of an account to capture the tax impact of the following differences:

- differences that result from a legislative or regulatory change to the tax rates or rules, and
- differences that result from a change in, or a disclosure of, a new assessing or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities

Hydro One Distribution has been charging the amount related to the reduction of the Capital Tax rate to this account since May 1, 2007. The amount related to the elimination of the Large Corporation Tax was charged to this account from May 1, 2006 to April 30, 2007.

The balance in Hydro One Distribution's Tax Rate Changes Account is summarized in Table 4 below:

Table 4
Distribution
Tax Rate Changes Account Balances
$ million

Description	USofA Account Ref	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Tax Rate Changes	1592	0	(2.8)	(4.7)	(5.0)

2.3 Smart Metering Minimum Functionality Expenditures incurred before May 31, 2007

As part of the RP-2005-0020/EB-2005-0378 Proceeding the OEB approved an incremental fixed monthly charge of $0.27 per metered customer, applicable as of May 1, 2006, to start collecting funds for the deployment of Smart Meters. Subsequently, as part of the EB-2007-0542 Proceeding, the monthly amount was increased to $0.93 per metered customer as of May 1, 2007. The revenues collected per the above are recorded in a variance account set up for Smart Meter revenue.

On May 2, 2007, the Board issued a notice of combined proceeding (EB-2007-0063) to determine the prudence and recovery of costs associated with smart metering activities for 13 licensed distributors, including Hydro One Networks

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The issues considered in the combined proceeding included:

1. Costs recovery relating to minimum functionality pursuant to Ontario Reg. 426/06.
2. Prudence of costs incurred.
3. The mechanism for re-setting rates for smart meter costs that are found to be prudent through this proceeding.
4. Accounting Procedures.
5. Regulatory treatment of stranded meter costs and recovery through rates.
6. The mechanisms for re-setting rates for smart meter costs incurred on a go forward basis.
7. Mechanism for dealing with costs not part of this proceeding.

The Board's Decision was released on August 8, 2007. The Board determined that the purchasing decisions of the thirteen utilities involved in this proceeding were implemented with the necessary due diligence and the terms of the contracts are prudent. The Board agreed with the overall costs incurred to May 31, 2007 related to the minimum functionality of all installed meters. These approved amounts were OM&A costs of $8.366 million, and Capital costs of $21.799 million. The approved amounts include only one half of the $1.348 million of project management capital costs incurred to May 31, 2007, and the Board requested Hydro One to include the remainder, or $0.674 million, in this application with a further explanation of these costs. This is included in Section 2.5 below. The Board also requested that the $70,000 of costs for repairing or replacing meter bases incurred to date and in the future be tracked in a variance account. This is included in Section 2.4 below.

Table 5 below details the revenue requirement (net of revenue received) related to smart meter minimum functionality up to May 31, 2007 that Hydro One is requesting recovery

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for in this proceeding. The revenue requirement was calculated based on the approach illustrated in Appendix E of the decision for proceeding EB-2007-0063.

Table 5
Distribution
Smart Meter Minimum Functionality Under-Recovery to May 31, 2007
$ million

Description	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Revenue Requirement	6.1	10.6	11.7
Less: Revenue	(2.5)	(4.8)	(4.8)
Net Revenue Requirement to be Recovered	**3.6**	**5.8**	**6.9**

2.4 Smart Metering Expenditures Exceeding Minimum Functionality

The Smart Metering Expenditures Exceeding Minimum Functionality primarily includes TOU capability as well as some costs for outage detection capability as described below:

Meter Outage Detection Capability

Super capacitors are being installed in the meters so they have the power to communicate outage event information after loss of electrical supply. In cases where meters can notify Hydro One of "nested" outages, this will enable Hydro One to become aware of outages in our rural areas in a timely manner, resulting in increased customer satisfaction and efficiency. Currently Hydro One has to rely on customer calls to be made aware of initial and remaining power outages.

Collector Outage Detections Capability

Battery backup for the collectors is included to ensure the meter outage events can be communicated through the collectors even when power supply to them has been interrupted. This capability is important as it ensures that the outage capability in the meter described above follows through to our central control offices.

TOU (Time of Use) Capability and Integration

The ultimate benefit of smart meters is to provide proper price signals to customers based on when they use electricity. TOU functionality is therefore an imperative element of the smart meter program. The TOU functionality will be provided through the communication network work as discussed in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2. This will integrate the meter information into the format needed for the IESO to use in the meter data management and meter data repository (MDMR).

The review of these costs were not part of the Combined Smart Metering Hearing (EB-2007-0063) since the proceeding only reviewed costs associated with minimum functionality.

The $70,000 of costs for repairing or replacing meter bases incurred to date were initially included in minimum functionality. The Board in their decision for EB-2007-0063 directed that these costs be separated out and tracked in a variance account. These costs and future repair costs through April 2008 are included in the table below and are being split between OM&A and capital as requested in the decision in EB-2007-0063.

The Hydro One Smart Meter revenue requirement associated with these elements is summarized in Table 6 below:

Table 6
Distribution
Smart Meter Exceeding Minimum Functionality Under-Recovery
$ million

Description	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Revenue Requirement	0.6	3.4	5.7

2.5 Smart Metering Minimum Functionality Expenditures between June 1, 2007 and April 30, 2008

The final area of Smart Meter expenditures include elements that were reviewed and approved in the Combined Smart Meter Proceeding (EB-2007-0063) but are related to the period June 1, 2007 to April 30, 2008 and therefore not part of the Decision delivered on August 8, 2007. These expenditures include the cost of meters that were included in the Smart Meter proceeding but were not yet installed. All of these meters will be installed by April 30, 2008.

The total number of meters that will be installed during this period is 522,086 for a total number of meters of 610,000. Using the Board's unit cost methodology, the unit cost in this time period has decreased from $479.47 to $428.00.

The Project management costs of $0.674 million that were not approved in the Smart Meter proceeding, as discussed in Section 2.3 above, have also been included in the costs below.

Due to the scope, complexity and specialized nature of this work, Hydro One selected Capgemini as its systems integrator, which includes providing the project management function. Capgemini was selected in 2005 as the systems integrator through a competitive RFP process. Hydro One's smart meter program has established detailed requirements to design, build, test, and commission the end to end solution to provide customers the tools and systems needed to take advantage of a smart meter system. Much of this work requires long lead times and is tied to external party timelines such as the IESO's implementation of the MDMR.

The Program Management function provides full Project Management Office (PMO) services and tools for a project that includes 12 work streams:

- Meter installation and field services
- Commissioning of head-end systems (advanced metering control computer, or "AMCC", for 1.2 million meter points)
- Network Engineering
- Integration of AMCC to MDMR to Hydro One's customer information system (CIS)
- Billing and customer care
- Settlements (retail and wholesale impact assessment)
- Customer Contact Centre (call centre to handle meter installation and TOU customer enquiries)
- CIS upgrade for TOU rates
- New systems – data and synchronization gateway and exception management for transactions exceeding 30 million per day upon full implementation
- Integrated business process design for moving from manual meter reading to an advanced metering regional collector (AMRC), including all related service orders, managing a network that encompasses over one million communication nodes, TOU billing, etc.
- Infrastructure Management (managing the procurement and implementation of computer hardware required for AMCCs, Integration, and TOU upgrades, this includes all required environments, e.g. for development, testing and production)
- Project management and tracking, which includes the following activities;
    - tracking cost and schedule performance; management of issues, risks, assumptions and change logs and associated action plans for all workstreams;

- the development and operation of a quality management program for the project;
- the development and operation of a project governance plan; and
- the development and maintenance of the integrated project plan.

The services above are the project related functions typically provided by the systems integrator. Although Hydro One is providing overall project management and direction to Capgemini, the competitively tendered role of PMO described above is not a role that Hydro One is able to resource internally. As noted in Exhibit D1, Tab 3, Schedule 2, the total project management costs on a per installed smart meter unit are forecast to drop from $21.7 per unit, based on costs and units installed to the end of May 2007, to $7.2 per unit based on total costs and units installed to the end of 2008.

The total Minimum Functionality net revenue requirement between June 1, 2007 and April 30, 2008 is summarized in Table 7 below:

Table 7
Distribution
Smart Meter Minimum Functionality Under-Recovery between
June 1, 2007 and April 30, 2008
$ million

Description	Dec 31, 2006	Dec 31, 2007	April 30, 2008
Revenue Requirement	0.0	11.3	21.4
Less: Revenue	0.0	(7.6)	(12.0)
Net Revenue Requirement to be Recovered	**0.0**	**3.7**	**9.4**

2.6 Retail Settlement Variance Accounts (RSVA)

The RSVA accounts have been established pursuant to Article 490 which requires that all distributors establish Retail Settlement Variance Accounts to record the differences between the amount owed to the IESO / host distributors and the amount billed to customers and retailers.

The vast majority of the balance in the RSVA accounts is related to Wholesale Market Services (WMS). The purpose of the WMS account is to capture the net of the amounts charged by the IESO, host distributors, and embedded generators (based on the settlement invoices for the operation of the IESO administered markets and the IESO – controlled grid) and the revenue accrued for customers using the Board approved Wholesale Market Service Rate.

The RSVA accounts were previously reviewed and approved by the Board in RP-2004-0117/0118 and RP-2005-0020 / EB-2005-0378. The balance of the RSVA account has been filed with the Board on a quarterly basis per the Electricity Reporting and Record Keeping Requirements and is included in the Board's annual review of deferral account balances.

Pursuant to the Board's October 29, 2007 letter to Electricity Distributors re: "Ontario Uniform Transmission Rate Order, EB-2007-0759: Effect on Distributor Retail Transmission Rates", which directs Distributors to incorporate the disposition of variance account balances relating to retail transmission rates in their 2008 Cost of Service application, Hydro One is requesting disposition of RSVA balances in this submission.

The total Retail Settlement Variance Accounts balance is summarized in Table 8 below:

Table 8
Distribution
Retail Settlement Variance Accounts
$ million

Description	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
RSVA Wholesale Market Services	0.6	(23.8)	(60.3)	(72.6)
RSVA Tx Network & Tx Network Aggregation	1.4	7.6	12.5	1.4
RSVA Tx Connection & Tx Connection Aggregation	1.6	5.4	7.5	2.5
RSVA Provincial Benefit	5.6	7.8	0.0	0.0
RSVA Low Voltage	0.0	0.8	3.0	3.8
Total RSVA	9.2	(2.2)	(37.3)	(64.8)

2.7 Accounts Not Being Requested For Recovery

2.7.1 RCVA and RRRP Accounts

RCVA and RRRP deferral accounts are currently being tracked by Hydro One Distribution but are not being requested for recovery as part of this proceeding. Balances in these accounts will continue to be filed with the Board on a quarterly basis per the Electricity Reporting and Record Keeping Requirements and included in the Board's annual review of deferral account balances.

2.7.2 Regulatory Asset Recovery Account – Phase I

Ontario's local electricity distribution companies (LDCs or distributors) incurred costs in preparation for the competitive market which opened in May 2002. In addition to these transition costs, utilities incurred other costs associated with regulatory directives related to market restructuring and the ongoing competitive market.

On January 10, 2005, the Board issued an *Order* (RP-2004-0117/0118) granting Hydro One approval for its regulatory asset account balance of $155 million as filed on December 20, 2004.

Simple interest is applied to the monthly opening principal balance in this account.

The Recovery of Regulatory Asset Balances – Phase I account (USofA 1590) is monitored and reported on a quarterly basis to the Board per the Electricity Reporting and Record Keeping Requirements. A final reconciliation (and true up adjustment) will be done at the end of the three year duration of the rate rider (April 30, 2008 for Distribution customers with volumetric rate riders, and March 31, 2008 for Embedded LDCs and Directs with fixed dollar amount rate riders).

2.7.3 Regulatory Asset Recovery Account – Phase II

On August 17, 2005, Hydro One Distribution filed an application with the Board for an order approving or fixing just and reasonable rates for the distribution of electricity effective May 1, 2006. On April 12, 2006, the Board issued a *Decision with Reasons* (RP-2005-0020 / EB-2005-0378) granting Hydro One approval for its regulatory asset account balances of $100 million as approved for Rate Rider recovery under that application.

Simple interest is applied to the monthly opening principal balance in this account.

The Recovery of Regulatory Asset Balances – Phase II account (USofA 1590) is monitored and reported on a quarterly basis to the Board per the Electricity Reporting and Record Keeping Requirements. A final reconciliation (and true up adjustment) will be done at the end of the four year duration of the rate rider (April 30, 2010).

PLANNED DISPOSITION OF REGULATORY ASSETS

1.0 INTRODUCTION

The purpose of this evidence is to outline the planned disposition of Regulatory Assets.

2.0 PLANNED DISPOSITION OF REGULATORY ASSETS

Hydro One Distribution is requesting approval to reduce the annual revenue requirements over a four year period by the Regulatory Asset total balance of $(48.7) million, or $(12.2) million per year.

Hydro One Distribution is requesting disposition of Regulatory Asset balances up to April 30, 2008. Balances as of April 30, 2008 are reasonably predictable. Allowing disposition of balances up to April 30, 2008 is more efficient as it provides the opportunity to close out certain deferral accounts. For the purposes of this filing, April 30, 2008 was chosen as it is assumed approved Distribution rates will be in place at the beginning of May 2008.

Hydro One Distribution's requested reduction to the Revenue Requirement of $(48.7) million is detailed in Table 1:

Table 1
Distribution
Disposition of Regulatory Asset Balances ($ Millions)

Description	Balance April 30, 2008
OEB Costs Account	(0.9)
Tax Changes Account	(5.0)
Smart Meter Minimum Functionality Under-recovery to May 31, 2007	6.9
Smart Meter Exceeding Minimum Functionality Under-recovery	5.7
Smart Meter Minimum Functionality Under-recovery between June 1, 2007 and April 30, 2008	9.4
Retail Settlement Variance Accounts	(64.8)
Total Requested for Disposition	**(48.7)**

Hydro One Distribution is requesting a reduction to the Revenue Requirement by the amounts detailed in Table 1 over a four year period to maintain consistency with previous recovery periods approved for Regulatory Accounts within the Electricity Transmission and Distribution Businesses, such as the 2006 Distribution Rate Proceeding (RP-2005-0020 / EB-2005-0378) and the 2004 Regulatory Assets Review Proceeding (RP-2004-0117/0118).

A Regulatory Asset Recovery Account will be established for any difference between the amount of Regulatory Assets approved and the actual value of the Regulatory Assets detailed above as at April 30, 2008. This variance will continue to be tracked and will be interest improved on a monthly basis (using a simple interest calculation) at the OEB approved rate. This account will be reported to the Board on a quarterly basis consistent with the Electricity Reporting and Record Keeping Requirements and subject to the Board's annual Regulatory Asset Review.

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VARIANCE ACCOUNTS REQUESTED

This exhibit requests approval to establish new variance accounts for Hydro One Distribution as follows:

- Pension Cost Differential
- OEB Cost Differential
- Bill Impact Mitigation

The need for these accounts and the accounting and control process is described in further detail in the remainder of this exhibit.

1.0 PENSION COST DIFFERENTIAL

Hydro One Distribution proposes to track the difference between actual pension costs booked using the actuarial assessment, provided by Mercer Human Resource Consulting, and the estimated pension costs used in this rate filing. Hydro One's actuarial valuation was prepared as at December 31, 2006 and was filed with FSCO in September 2007.

2.0 OEB COST DIFFERENTIAL

This account will track the difference between the annual OEB Cost Assessments, intervenor cost awards, and costs associated with OEB-initiated studies and the amount for these expenditures approved by the OEB as part of the 2008 Distribution Rates until these rates are rebased.

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3.0 BILL IMPACT MITIGATION

This account will record the difference between Hydro One's requested revenue requirement and distribution rates resulting from the Application of the Cost Allocation for Electricity Distributors report issued by the Board on November 28, 2007. In this report the Board indicated that Distributors should endeavor to move their revenue-to-cost ratios within an acceptable range which is closer to one but should not move them away from one and be cognizant of customer bill impacts. To comply with these requirements, Hydro One Distribution proposed rates will result in a revenue differential of $2.5 million. The establishment of the Bill Impact Mitigation variance account will enable this balance to be recorded and submitted for recovery at a future proceeding. The intent of this account is similar in nature to the MEU Rate Mitigation account approved by the Board in their RP-2005-0014/EB-2005-0099 to 0185 decision At that time, the Board directed Hydro One to limit the rate increase to no more than 10 percent on the average customer's total bill and recognized that Hydro One would have a revenue shortfall. The Board wrote that they would allow for the recovery of this deferred revenue in future years.

4.0 ACCOUNTING AND CONTROL PROCESS

The variance accounts requested above will be managed in the same manner as existing Hydro One Distribution variance accounts. Accounts will be updated monthly and interest applied consistent with the Board approved rate. Balances will be reported to the Board as part of the quarterly reporting process. The outstanding balance whether in a debit or credit position will be submitted for approval by the Board as part of Hydro One Distribution's next rate filing.

HYDRO ONE NETWORKS INC.
DISTRIBUTION
Regulatory Assets for Approval
As at April 30, 2008
($ Millions)

Line No.	Particulars	Principal (a)	Interest (b)	Total (c)
1	OEB Costs	(0.8)	(0.1)	(0.9)
2	Tax Rate Change	(4.7)	(0.3)	(5.0)
3	Smart Meter Minimum Functionality to May 31, 2007	6.5	0.4	6.9
4	Smart Meter Costs Exceeding Minimum Functionality	5.5	0.2	5.7
5	Smart Meter Minimum Functionality after May 31, 2007	9.2	0.2	9.4
6	Retail Settlement Variance Accounts	(63.3)	(1.5)	(64.8)
7	**Total Regulatory Assets for Approval**	**$ (47.6)**	**$ (1.1)**	**$ (48.7)**

HYDRO ONE NETWORKS INC.
DISTRIBUTION

Schedule of Annual Recoveries*
Year Ending December 31
($ Millions)

Line No.	Particulars	2008 (a)	2009 (b)	2010 (c)	2011 (d)	2012 (e)	Total (f)
1	Requested Recovery of Pending Assets	(8.1)	(12.2)	(12.2)	(12.2)	(4.1)	(48.7)

* Note: above figures do not include interest improvement

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Ontario Energy Board (Board Staff) INTERROGATORY #119 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1

Usual practice in the electricity sector is to use audited numbers for the last fiscal years as the basis for balances in the deferral and variance accounts for disposition, with interest forecasted up to the start of the new rate year.

a. Please provide the regulatory precedent for principal transactions being forecasted beyond December 31, 2006 for accounts requested for disposition.
b. Please recalculate the appropriate rate rider schedules using the December 31, 2006 balances with interest forecasted to April 30, 2008.

Response

a. The regulatory precedent can be found in RP-2005-0020 (EB-2005-0378), 2006 Electricity Distribution Rates. In the Hydro One Distribution submitted evidence, audited financial statements were provided up to December 31, 2004 and Regulatory Asset balances were projected to April 30, 2006. Those projected balances were approved by the Board on April 12, 2006 (subject to interest rate changes).

b. See Attachment A for recalculated rate rider schedule.

Regulatory Asset Recovery 2007 Scenario

Stats for Allocation			Formula	UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	Dgen	ST
Cust	1,177,552		A	162,058	376,430	364,938	155,177	97,005	7,015	12,744	1,429	-	-	84	673
GWh	38,411		B	1,494	4,407	5,624	707	2,299	3,237	424	831	121	22	3.4	19,240
GWh excl WMP	24,267		C	1,494	4,407	5,624	707	2,299	3,237	424	831	121	22	3.4	5,096
GWh excl WMP & excl RRP	9,167		D						3,237		831			3	5,096
Billing kWs	56,293,509		E						11,019,445		2,203,297			48,843	43,021,924
Dx Rev excl Riders [$M]	1,024		F	53.9	186.5	392.6	74.8	113.9	105.5	11.6	15.7	4.8	0.9	0.6	63.4
OMA	100%		G	6.76%	24.04%	38.79%	8.06%	10.48%	7.19%	0.93%	0.96%	0.64%	0.18%	0.01%	1.96%
NFA	100%		H	5.78%	21.57%	35.38%	7.62%	10.52%	12.37%	0.90%	2.13%	0.89%	0.19%	0.01%	2.64%
Balances	$ 1000s	**Allocator**													
Provincial Benefit	8,308	GWh excl WMP & RRP	I	$ -	$ -	$ -	$ -	$ -	$ 2,933.9	$ -	$ 752.9	$ -	$ -	$ 3.1	$ 4,618.2
RSVA Wholesale Market Service Charges	(25,354)	GWh excl WMP	J	$ (1,561.1)	$ (4,604.9)	$ (5,876.5)	$ (738.4)	$ (2,402.3)	$ (3,382.4)	$ (443.2)	$ (868.0)	$ (126.0)	$ (23.4)	$ (3.5)	$ (5,324.3)
RSVA Tx Network	8,026	GWh	K	$ 312.2	$ 921.0	$ 1,175.3	$ 147.7	$ 480.5	$ 676.5	$ 88.6	$ 173.6	$ 25.2	$ 4.7	$ 0.7	$ 4,020.4
RSVA Tx Connection	5,763	GWh	L	$ 224.2	$ 661.2	$ 843.8	$ 106.0	$ 345.0	$ 485.7	$ 63.6	$ 124.6	$ 18.1	$ 3.4	$ 0.5	$ 2,886.6
RSVA LV Wheeling	901	GWh	M	$ 35.1	$ 103.4	$ 132.0	$ 16.6	$ 54.0	$ 76.0	$ 10.0	$ 19.5	$ 2.8	$ 0.5	$ 0.1	$ 451.5
OEB Costs	(930)	OMA	N	$ (62.8)	$ (223.5)	$ (360.6)	$ (74.9)	$ (97.4)	$ (66.8)	$ (8.6)	$ (9.0)	$ (5.9)	$ (1.7)	$ (0.1)	$ (18.2)
Tax Change	(2,991)	NFA	O	$ (173.0)	$ (645.1)	$ (1,058.4)	$ (227.9)	$ (314.6)	$ (370.0)	$ (26.9)	$ (63.8)	$ (26.7)	$ (5.7)	$ (0.2)	$ (78.9)
Smart Meter Minimum Functionality to May 31, 2007	3,874	Cust #	P	$ 533.1	$ 1,238.3	$ 1,200.5	$ 510.5	$ 319.1	$ 23.1	$ 41.9	$ 4.7	$ -	$ -	$ 0.3	$ 2.2
Smart Meter Costs Exceeding Minimum Functionality	681	Cust #	Q	$ 93.7	$ 217.8	$ 211.1	$ 89.8	$ 56.1	$ 4.1	$ 7.4	$ 0.8	$ -	$ -	$ 0.0	$ 0.4
Smart Meter Minimum Functionality after May 31, 2007	-	Cust #	R	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Regulatory Assets for Approval	$ (1,722)														
	$ (1,721.5)		S	$ (598.6)	$ (2,331.9)	$ (3,732.8)	$ (170.6)	$ (1,559.8)	$ 379.9	$ (267.2)	$ 135.4	$ (112.5)	$ (22.3)	$ 0.9	$ 6,557.9
Assuming a 4 year recovery	$ (430.4)		T = R/4	$ (149.7)	$ (583.0)	$ (933.2)	$ (42.7)	$ (389.9)	$ 95.0	$ (66.8)	$ 33.9	$ (28.1)	$ (5.6)	$ 0.2	$ 1,639.5
	Rider 3	c/kWh	T/B	(0.010)	(0.013)	(0.017)	(0.006)	(0.017)	0.003	(0.016)	0.004	(0.023)	(0.025)	0.007	0.009
	$ (1,721.5)	$/kW	T/E						0.009		0.015			0.005	0.038
	Rider 3 Filed	c/kWh		(0.025)	(0.037)	(0.049)	0.017	(0.057)	(0.074)	(0.059)	(0.072)	(0.080)	(0.082)	(0.061)	(0.015)
	$ (12,170.0)	$/kW		-	-	-	-	-	(0.217)	-	(0.273)	-	-	(0.042)	(0.067)

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Ontario Energy Board (Board Staff) INTERROGATORY #120 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1
Tables 5, 6 and 7 at Exhibit F1/Tab 1/Schedule 1 relate to "Net Revenue Requirement to be Recovered".

a. Please provide in one consolidated table the Net Revenue Requirement to be Recovered for minimum functionality covered in table 5 and 7 in accordance with Appendix E of the EB-2007-0063 Decision on Smart Meters. Please also include in this table the smart metering capital that the return on equity and interest expense is being calculated from as well as the capital structure being relied on in these calculations.
b. Is Hydro One currently using accounts 1555 and 1556?
c. Please identify any deviations from the Board's guidance with respect to these accounts.
d. Is Hydro One planning to continue these accounts after April 30th, 2008?
e. Is Hydro One planning on continuing to charge the rate rider associated with Smart Metering. If so, why?
f. Please provide a detailed calculation of revenue requirement for Table 6, Smart Meter Exceeding Minimum Functionality Under-Recovery

Response

a. The attached (Attachment A) spreadsheet provides the calculation of net revenue requirement for each of the three smart meter regulatory assets, consistent with the amounts shown in Tables 5, 6, and 7 in Exhibit F1, Tab 1, Schedule 1. The spreadsheet contains the calculation of forecast annual rate base, annual revenue requirement, and cumulative net revenue requirement as at year-end 2006, year-end 2007, and April 30, 2008 for each of the smart meter regulatory assets.

b. Yes

c. Hydro One is in compliance with Board guidance for use of these accounts.

d. Yes, except that we are not expecting to use the interim recoveries account after the date of implementation of the 2008 Distribution rate change.

e. No, Hydro One will stop recovery of the rate rider related to recovery of interim smart meter costs effective the date of the implementation of the 2008 Distribution rate change.

f. See response to part a.

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - up to May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Return on rate base				
Opening fixed assets:				
Gross assets	0.0	2.2	21.1	
Less: Accumulated depreciation	0.0	(0.1)	(0.9)	
Net fixed assets	0.0	2.1	20.3	
Closing fixed assets:				
Gross assets	2.2	21.1	21.1	
Less: Accumulated depreciation	(0.1)	(0.9)	(1.3)	
Net fixed assets	2.1	20.3	19.8	
Average fixed assets	1.1	11.2	20.0	
Working capital	0.9	0.4	0.0	
Total rate base	1.9	11.6	20.0	
Cost of debt	0.1	0.4	0.2	Pro-rated for number of months in period
Return on equity	0.1	0.4	0.2	Pro-rated for number of months in period
Return on rate base	0.1	0.8	0.5	
Revenue requirement before PILs				
OM&A	5.8	2.6	0.0	Pro-rated for number of months in period
Depreciation	0.1	0.8	0.5	Pro-rated for number of months in period
Return on rate base	0.1	0.8	0.5	
Revenue requirement before PILs	6.0	4.1	0.9	
PILs				
Revenue requirement before PILs	6.0	4.1	0.9	
Less: OM&A	(5.8)	(2.6)	0.0	
Less: Depreciation	(0.1)	(0.8)	(0.5)	
Less: Interest	(0.1)	(0.4)	(0.2)	
Income for PILs purposes	0.1	0.4	0.2	
Add depreciation	0.1	0.8	0.5	
Deduct CCA	(0.1)	(0.9)	(0.5)	Pro-rated for number of months in period
Taxable income for PILs purposes	0.1	0.3	0.2	
PILs before gross up	0.0	0.1	0.1	
Grossed up PILs	0.0	0.1	0.1	
Revenue requirement				
Revenue requirement before PILs	6.0	4.1	0.9	
Grossed up PILs	0.0	0.1	0.1	
Revenue requirement	6.0	4.3	1.0	
Under-recovery				
Revenue requirement	6.0	4.3	1.0	
Less: Revenue earned	(2.5)	(2.3)	0.0	
	3.6	2.0	1.0	
Carrying charge	0.1	0.2	0.1	Pro-rated for number of months in period
Under-recovery	3.6	2.2	1.1	
Cumulative balance	3.6	5.8	6.9	

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Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - up to May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Inputs				
OM&A	5.8	2.6	0.0	Per OEB decision (August 8, 2007)
Capital (I/S additions)	2.2	18.9	0.0	Per OEB decision (August 8, 2007)
Interim revenue	2.5	2.3	0.0	
Number of months in period	12	12	4	
Working capital (% of OM&A)	15%	15%	15%	
Depreciation life (years)	15	15	15	
CCA rate (%)	8%	8%	8%	
Cost of debt (%)	5.93%	5.93%	5.93%	Weighted average cost of debt per 2006 Dx filing
Cost of equity (%)	8.65%	8.65%	8.65%	Weighted average cost of equity per 2006 Dx filing
Deemed equity (%)	40%	40%	40%	Per 2006 Dx filing
Tax rate (%)	36.12%	36.12%	34.50%	
Interest rate on reg assets	4.59%	4.64%	4.74%	

Detailed calculations

Depreciation	2006	2007	Jan-Apr 2008
Opening gross fixed assets	0.0	2.2	21.1
Closing gross fixed assets	2.2	21.1	21.1
Average gross fixed assets	1.1	11.7	21.1
Depreciation	0.1	0.8	1.4

CCA	2006	2007	Jan-Apr 2008
Opening UCC	0.0	2.1	20.1
Plus: Additions	2.2	18.9	0.0
Less: CCA	(0.1)	(0.9)	(1.6)
Closing UCC	2.1	20.1	18.5
UCC for CCA	1.1	11.6	20.1
CCA	0.1	0.9	1.6

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - post May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Return on rate base				
Opening fixed assets:				
Gross assets	0.0	0.3	77.5	
Less: Accumulated depreciation	0.0	(0.0)	(2.6)	
Net fixed assets	0.0	0.3	74.9	
Closing fixed assets:				
Gross assets	0.3	77.5	209.3	
Less: Accumulated depreciation	(0.0)	(2.6)	(5.8)	
Net fixed assets	0.3	74.9	203.5	
Average fixed assets	0.1	37.6	139.2	
Working capital	0.0	0.8	1.3	
Total rate base	0.1	38.4	140.5	
Cost of debt	0.0	1.4	1.7	Pro-rated for number of months in period
Return on equity	0.0	1.3	1.6	Pro-rated for number of months in period
Return on rate base	0.0	2.7	3.3	
Revenue requirement before PILs				
OM&A	0.0	5.5	2.9	Pro-rated for number of months in period
Depreciation	0.0	2.6	3.2	Pro-rated for number of months in period
Return on rate base	0.0	2.7	3.3	
Revenue requirement before PILs	0.0	10.7	9.4	
PILs				
Revenue requirement before PILs	0.0	10.7	9.4	
Less: OM&A	0.0	(5.5)	(2.9)	
Less: Depreciation	(0.0)	(2.6)	(3.2)	
Less: Interest	(0.0)	(1.4)	(1.7)	
Income for PILs purposes	0.0	1.3	1.6	
Add depreciation	0.0	2.6	3.2	
Deduct CCA	(0.0)	(3.1)	(3.7)	Pro-rated for number of months in period
Taxable income for PILs purposes	0.0	0.8	1.1	
PILs before gross up	0.0	0.3	0.4	
Grossed up PILs	0.0	0.5	0.6	
Revenue requirement				
Revenue requirement before PILs	0.0	10.7	9.4	
Grossed up PILs	0.0	0.5	0.6	
Revenue requirement	0.0	11.2	10.0	
Under-recovery				
Revenue requirement	0.0	11.2	10.0	
Less: Revenue earned	0.0	(7.6)	(4.4)	
	0.0	3.6	5.6	
Carrying charge	0.0	0.1	0.1	Pro-rated for number of months in period
Under-recovery	0.0	3.7	5.7	
Cumulative balance	0.0	3.7	9.4	

Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Minimum Functionality - post May 31, 2007

($ millions)	2006	2007	Jan-Apr 2008	Comments
Inputs				
OM&A	0.0	5.5	8.8	
Capital (I/S additions)	0.3	77.2	131.8	
Interim revenue	0.0	7.6	4.4	
Number of months in period	12	12	4	
Working capital (% of OM&A)	15%	15%	15%	
Depreciation life (years)	15	15	15	
CCA rate (%)	8%	8%	8%	
Cost of debt (%)	5.93%	5.93%	5.93%	Weighted average cost of debt per 2006 Dx filing
Cost of equity (%)	8.65%	8.65%	8.65%	Weighted average cost of equity per 2006 Dx filing
Deemed equity (%)	40%	40%	40%	Per 2006 Dx filing
Tax rate (%)	36.12%	36.12%	34.50%	
Interest rate on reg assets	4.59%	4.64%	4.74%	
Detailed calculations				
Depreciation				
Opening gross fixed assets	0.0	0.3	77.5	
Closing gross fixed assets	0.3	77.5	209.3	
Average gross fixed assets	0.2	38.9	143.4	
Depreciation	0.0	2.6	9.6	
CCA				
Opening UCC	0.0	0.3	74.3	
Plus: Additions	0.3	77.2	131.8	
Less: CCA	(0.0)	(3.1)	(11.2)	
Closing UCC	0.3	74.3	194.9	
UCC for CCA	0.2	38.9	140.3	
CCA	0.0	3.1	11.2	

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Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Exceed Minimum Functionality

($ millions)	2006	2007	Jan-Apr 2008	Comments
Return on rate base				
Opening fixed assets:				
Gross assets	0.0	0.6	24.6	
Less: Accumulated depreciation	0.0	(0.0)	(0.9)	
Net fixed assets	0.0	0.6	23.8	
Closing fixed assets:				
Gross assets	0.6	24.6	57.6	
Less: Accumulated depreciation	(0.0)	(0.9)	(1.8)	
Net fixed assets	0.6	23.8	55.8	
Average fixed assets	0.3	12.2	39.8	
Working capital	0.1	0.1	0.1	
Total rate base	0.4	12.3	39.9	
Cost of debt	0.0	0.4	0.5	Pro-rated for number of months in period
Return on equity	0.0	0.4	0.5	Pro-rated for number of months in period
Return on rate base	0.0	0.9	0.9	
Revenue requirement before PILs				
OM&A	0.6	0.8	0.3	Pro-rated for number of months in period
Depreciation	0.0	0.8	0.9	Pro-rated for number of months in period
Return on rate base	0.0	0.9	0.9	
Revenue requirement before PILs	0.6	2.5	2.1	
PILs				
Revenue requirement before PILs	0.6	2.5	2.1	
Less: OM&A	(0.6)	(0.8)	(0.3)	
Less: Depreciation	(0.0)	(0.8)	(0.9)	
Less: Interest	(0.0)	(0.4)	(0.5)	
Income for PILs purposes	0.0	0.4	0.5	
Add depreciation	0.0	0.8	0.9	
Deduct CCA	(0.0)	(1.0)	(1.1)	Pro-rated for number of months in period
Taxable income for PILs purposes	0.0	0.3	0.3	
PILs before gross up	0.0	0.1	0.1	
Grossed up PILs	0.0	0.1	0.2	
Revenue requirement				
Revenue requirement before PILs	0.6	2.5	2.1	
Grossed up PILs	0.0	0.1	0.2	
Revenue requirement	0.6	2.6	2.3	
Under-recovery				
Revenue requirement	0.6	2.6	2.3	
Less: Revenue earned	0.0	0.0	0.0	
	0.6	2.6	2.3	
Carrying charge	0.0	0.1	0.1	Pro-rated for number of months in period
Under-recovery	0.6	2.7	2.4	
Cumulative balance	0.6	3.4	5.7	

Filed: April 4, 2008
EB-2007-0681
Exhibit H-1-120
Attachment A
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Calculation of Smart Meter Under-Recovery (to April 30, 2008)
Exceed Minimum Functionality

($ millions)	2006	2007	Jan-Apr 2008	Comments
Inputs				
OM&A	0.6	0.8	0.9	
Capital (I/S additions)	0.6	24.0	33.0	
Interim revenue	0.0	0.0	0.0	
Number of months in period	12	12	4	
Working capital (% of OM&A)	15%	15%	15%	
Depreciation life (years)	15	15	15	
CCA rate (%)	8%	8%	8%	
Cost of debt (%)	5.93%	5.93%	5.93%	Weighted average cost of debt per 2006 Dx filing
Cost of equity (%)	8.65%	8.65%	8.65%	Weighted average cost of equity per 2006 Dx filing
Deemed equity (%)	40%	40%	40%	Per 2006 Dx filing
Tax rate (%)	36.12%	36.12%	34.50%	
Interest rate on reg assets	4.59%	4.64%	4.74%	
Detailed calculations				
Depreciation				
Opening gross fixed assets	0.0	0.6	24.6	
Closing gross fixed assets	0.6	24.6	57.6	
Average gross fixed assets	0.3	12.6	41.1	
Depreciation	0.0	0.8	2.7	
CCA				
Opening UCC	0.0	0.6	23.6	
Plus: Additions	0.6	24.0	33.0	
Less: CCA	(0.0)	(1.0)	(3.2)	
Closing UCC	0.6	23.6	53.4	
UCC for CCA	0.3	12.6	40.1	
CCA	0.0	1.0	3.2	

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Ontario Energy Board (Board Staff) INTERROGATORY #117 List 1

Interrogatory

Ref: ExF1/Tab1/Sch1/ Issue 6.1
Hydro One stated that the amount related to the elimination of the Large Corporation Tax (LCT) was charged to account 1592 from May 1, 2006 to April 30, 2007. In July 2007, the Board released the 'APH Frequently Asked Questions' detailing how utilities were expected to account for the retroactive repeal of the LCT.

a. To what account did Hydro One book the period January 1st 2006 to April 30th 2006 repeal of the LCT?
b. If Hydro One has not recorded for the repeal of the LCT, please explain why?
c. Please provide a table similar to Exhibit F1/Tab1/Schedule1 page 5 Distribution Tax Rate Changes Account Balances to reflect the amount related to the elimination of the LCT from January 1st, 2006 to April 30th, 2007 into account1592.

Response

a. Hydro One Distribution calculated the impact of the elimination of the LCT as being a reduction in revenue requirement of $4.1M for the calendar year 2006. The full amount of this impact was booked to account 1592 over the rate year period from May 1, 2006 to April 30, 2007 (as this is the period during which Hydro One over-collected the revenue), and is included in the deferral account balance shown in Exhibit F1-1-1, Table 4.

b. See response to part a.

c. See response to part a.

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

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

Ontario

BY E-MAIL

March 3, 2008

To: All Licensed Electricity Distributors
All Intervenors in 2008 Electricity Distribution Rate Proceedings

Re: Review Initiative
Account 1562, Deferred Payments in Lieu of Taxes ("PILs")
Board file number EB-2007-0820

The majority of electricity distributors that are rate regulated by the Board became subject to PILs effective October 1, 2001 with the proclamation of section 93 of the *Electricity Act, 1998* (the "Act"). As of the date of this letter, seven distributors subject to section 93 of the Act that filed cost of service applications for 2008 rates have requested the disposition of account 1562, Deferred PILs. To date, the Board has not reviewed the methodology or account balances for account 1562 for any distributor subject to section 93 of the Act.

It is apparent from a review of applications before the Board that distributors have used a variety of methods to record balances in account 1562 for the time period applicable to this account, October 1, 2001 to April 30, 2006. This letter is to notify electricity distributors subject to section 93 of the Act and interested parties that the Board intends to initiate a combined proceeding to determine the methodology that should be used for the calculation and disposition of these balances.

Going forward, it is the Board's expectation that the decision stemming from the combined proceeding will be used to determine the final account balances with respect to account 1562, Deferred PILs for the remaining distributors. The Board intends to proceed with the review and disposition of the account 1562, Deferred PILs balances for the remaining distributors subsequent to the completion of the combined proceeding.

Further information regarding this initiative, including how to participate in it, will be made available in the near future. If you have any questions regarding this initiative, please contact Harold Thiessen, Senior Advisor, at 416-440-7637 or by e-mail at harold.thiessen@oeb.gov.on.ca.

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0680

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

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2008, May 1, 2009, and May 1, 2010.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

David Balsillie
Member

DECISION

May 15, 2008

distribution sector it is not the Board's practice to clear forecast balances which include principal.

Board staff also referred to the Board's Phase 2 Decision for the Review and Recovery of Regulatory Assets for the five large distributors (RP-2004-0117, RP-2004-0118, RP-2004-0100, RP-2004-0069, RP-2004-0064), and submitted that the Company's proposal to dispose of account 1590 before the final balance has been determined does not reflect a proper true-up. The Phase 2 Decision specifies that the rate rider associated with account 1590 be removed as of May 1, 2008. Once the residual balance in account 1590 is finalized, the residual balance is to be disposed at a future hearing. The final balance in account 1590 cannot be confirmed until after the current recovery period has expired, i.e. after April 30, 2008.

Board Findings

To the extent possible and practical, the balances of variance and deferral accounts that are approved for clearance should be measured at the same date for all distributors. In a few electricity rate cases, the Board has accepted settlement agreements that include clearance of deferral and variance accounts based on measurement dates other than the date of the most recent audited financial statements. In most other cases not involving settlement agreements, the Board usually approved only the disposition of actual audited balances.

The Board does not find any compelling reasons to make an exception to its general policy in this case and will not dispose of the 1590 account at this time.

With respect to account 1592, as the Board has commenced a combined proceeding which was announced on March 3, 2008 to deal with matters concerning pre April 30, 2006 PILs variances in account 1562, which may inform matters pertaining to the post April 30, 2006 PILs variance in account 1592, it will not dispose of this account in this proceeding. The Board notes that the Company withdrew its request in its initial filing to dispose of the balances in the 1562 account.

The Company requested the following two deferral/variance accounts: OEB Cost Assessments/Intervenors' Costs Awards/OEB Mandated Studies Account (for convenience "regulatory costs" account) and Capital Contributions account.

The regulatory costs account would track the differences in expenses reflected in rates and actual expenses associated with the named activities. The proposed amounts to be reflected in rates were $8.2 Million for 2008 and $7.8 Million for 2009.

The Capital Contributions account would track the difference between the rate impacts associated with actual capital contributions to Hydro One Networks and the impacts of contributions included in rates. The rate impacts included in the proposed rates were based on contributions of $5.0 Million for 2008 and $10.0 Million for 2009.

Board Findings

Variance and deferral accounts are governed by the Accounting Procedures Handbook (APH) and associated letters of the Board. All deferral and variance accounts are open to all electricity distributors and may be used according to the rules stated in the APH and associated documentation, unless specific Board findings apply for a utility with respect to the use of these accounts or other accounts. Therefore, there is no need for the Board in this proceeding to approve or not approve of the continuation of existing accounts. Similarly, the two proposed new accounts are of general sector applicability; they are not exclusive to the Applicant. As such, this matter requires a sector-wide approach through the APH or direction by the Board through another instrument.

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Ontario Energy Board
Accounting Procedures Handbook
Frequently Asked Questions
July 2007

INDEX

ACCOUNTING PROCEDURES HANDBOOK

Frequently Asked Questions

Q.1 The federal Large Corporation Tax ("LCT") was repealed in the Federal Government's 2006 Budget and was retroactive to January 1, 2006. Which APH accounts should be used to record the changes in tax legislation?

A.1 The Board approved accounts 1562 and 1592 to deal with changes in tax legislation and tax rules with respect to PILs and taxes. Account 1562 applies to entries up to April 30, 2006, while account 1592 relates to tax changes that affect the period after April 30, 2006. Account 1592 was specifically approved by the Board effective for the start of the 2006 rate year on May 1, 2006. Please refer to December 2005 FAQs, Q.19, for additional information on account 1592. Since there was no LCT cost to the distributor in 2006 (and beyond), no cost recovery is needed from rate-payers. Accordingly, both accounts should be used to record adjusting entries for LCT in the applicable periods indicated above.

Q.2 The distributor did not apply for 2006 rates, but had an LCT amount included in its previous rates. Which account should be used to record the LCT PILs tax entries?

A.2 Account 1562 should be used to record the adjusting entries for the period starting from January 1, 2006, up to the date the LCT component is removed from rates (e.g., May 1, 2007 or upon rates rebasing), since the previous distribution rates approved in the distributor's 2005 application, which included LCT, continued in rates during the period when the LCT legislative repeal came into effect (i.e., January 1, 2006).

Q.3 There is no schedule in the Rate Adjustment Model ("RAM") that isolated the LCT rate component in 2005 or in 2006. How does the distributor identify the amount that should be recorded?

A.3 If the distributor cannot identify how much LCT has been billed, or collected, from its customers, the amount can be estimated from the grossed-up LCT PILs or tax proxy included in rates for the 2005 and the 2006 rates applications, as applicable.

Q.4 How can the distributor calculate the required LCT amounts for the different time periods from the PILs or tax proxy?

A.4 The LCT amounts are in two parts since they relate to two rate years. The 2005 grossed-up LCT PILs or tax proxy was incorporated in rates for the period from April 1, 2005 to April 30, 2006. The 2006 EDR grossed-up LCT PILs or tax proxy was included in rates with effect from May 1, 2006 to April 30, 2007 for those distributors that applied for rate changes.

Take the 2005 grossed-up LCT proxy from the 2005 application PILs model, and divide the number by 12. Multiply this amount by four (4) to calculate the amount applicable to the period January to April 2006, and enter the credit for the amount in 1562. The debit entry is posted to account 4080. If the distributor did not apply for 2006 rates, the 12-month grossed-up LCT proxy from the 2005 application will be the amount to be recorded in 1562 for all of 2006 including up to the period indicated in A.2 above.

For the 1592 entry, take the 2006 EDR grossed-up LCT proxy from the PILs model and divide it by 12. Multiply this amount by 8 to calculate the amount for the period May 1 to December 31, 2006. Also, multiply this amount by four (4) to calculate the amount for the period from January 1 to April 30, 2007. The credit entries will be made to account 1592 and the debit entries will be made to account 4080 for the applicable periods.

The 2007 rate applications included an adjustment that removed the LCT component in PILs or taxes effective in rates on May 1, 2007 for those distributors that applied.

Q.5 Which interest rate should be used to calculate the simple interest carrying charge or credit in accounts 1562 and 1592?

A.5 Carrying charge amounts shall be calculated using simple interest applied to the monthly opening debit or credit balances in accounts 1562 and 1592 (exclusive of accumulated interest) and recorded in separate sub-accounts. In account 1562 for carrying charges up to the period ended April 30, 2006, the distributor shall use a rate of interest equal to its deemed debt rate set out in Chapter 3 of the 2000 Electricity Distribution Rate Handbook, Table 3-1. In account 1592

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

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

Ontario

BY E-MAIL

February 19, 2008

To: All Licensed Electricity Distributors
All Intervenors in 2008 Electricity Distribution Rate Proceedings
All Participants in Consultation Process EB-2007-0673

Re: Deferral Account Review Initiative
Board File Number: EB-2008-0046

The Board is required by section 78(6.1) of the *Ontario Energy Board Act, 1998* (the "Act") to make an order at least every three months to determine whether and how the amounts recorded in the commodity deferral or variance accounts of each electricity distributor shall be reflected in rates. Currently, these amounts are recorded in Account 1588 of the Uniform System of Accounts. The Board is also required by section 78(6.2) of the Act to make a similar order in respect of all non-commodity deferral or variance accounts at least annually.

This letter is to notify electricity distributors and interested parties that the Board intends to launch an initiative for the review and disposition of Account 1588. As part of that initiative, the Board will consider the use of account disposition thresholds or "disposition triggers", which would allow for a process commensurate with the nature of the deferral accounts in question. The Board will also consider whether to extend this initiative to deferral accounts that are similar in nature to Account 1588, such as the RSVA deferral accounts and RCVA deferral accounts.

Similar to other current Board initiatives, such as the Electricity Service Quality Regulation consultation (EB-2008-0001) and the Comparison of Ontario Electricity Distributor Costs consultation (EB-2006-0268), the Board expects that this new deferral account review initiative will inform the consultation regarding the development of the 3rd generation incentive rate regulation mechanism (EB-2007-0673).

Further information regarding this initiative, including how to participate in it, will be made available in the near future. If you have any questions regarding this initiative, please contact Adrian Pye, Manager, at 416-440-8139, or by e-mail at BoardSec@oeb.gov.on.ca. Any matters sent to the Board in relation to this consultation must quote file number **EB-2008-0046.**

Yours truly,

Original signed by

Kirsten Walli
Board Secretary

Ontario Energy Board (Board Staff) INTERROGATORY #123 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2

Hydro One is requesting a new deferral and variance account for the Pension Cost Differential.

a. Please provide the justification for this request, particularly identifying, when the actuarial valuation was prepared as at December 31, 2006, and when it was filed with FSCO and included in forecasted rates.
b. What is the proposed methodology for recording pension costs into this account (cash or accrual)? If Hydro One is proposing a change to the accrual method, is the company also proposing to record the difference between the expense embedded in rates and the accrual expense as per the audited financial statements, into this account?
c. In Hydro One's view what would the impact of its proposal be on the IRM 3 mechanism?
d. Can Hydro One identify any regulatory precedent in support of its proposal?
e. Please provide an estimate of the variance to be recorded in this account, if any.
f. What account number does Hydro One propose to use in the USoA?
g. What are the journal entries to be recorded?
h. When does Hydro One plan to ask for its disposition?
i. How does Hydro One plan to allocate this amount by rate class?
j. What new or additional information is available since the December 18, 2007 filing of this application that would improve the Board's ability to make a decision on this request?

Response

a. The actuarial valuation report as at December 31, 2006 was prepared during 2007, completed in August 2007 and filed with FSCO in September 2007. The actuarial report sets out the minimum funding requirements for the company that includes both a variable component as a function of base pensionable earnings, plus a fixed component for the deficiency in the plan. Given there is a variable component to the funding amount, there could be a difference between estimated pension costs being sought for recovery and actual pension costs. Since the actuarial valuation was filed with FSCO subsequent to the EB-2007-0681 evidence being filed with the OEB on August 15, 2007, the forecast amount of pension contribution was based on an estimate, rather than the final valuation. Thus, Hydro One Distribution is requesting a deferral account.

b. The Board has allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). Consistent with its prior Distribution rate application (RP-2005-0020/EB-2005-0378), Hydro One does not use the accrual method for rate setting purposes nor in its audited financial statements. Pension costs continue to be recorded on a cash basis and as such, there is no change from this basis.

c. It is premature to speculate as the IRM3 mechanism has not yet been established.

d. On July 14, 2004 the Board issued its Decision and Order (RP-2004-0180) approving the creation of a deferral account for Hydro One Distribution to record the pension costs and related interest. A similar account was approved as part of Hydro One Transmission's rate application (EB-2006-0501).

e. The estimated amount to be recorded in the variance account for 2008 is approximately $130 thousand (liability) per month.

f. Hydro One would use Account 1508 Other Regulatory Assets; Sub Account Pension Contributions

g. Where pension costs recovered through rates are higher than actual pension costs incurred, the entry will be:

   Dr. Revenue
      Cr. Pension Deferral Account (liability)

   Where pension costs recovered are less than actual pension costs incurred, the opposite entry would apply.

h. Hydro One would ask for disposition of this account as part of the next Cost of Service hearing.

i. This amount would be allocated to all rate classes. Consistent with the proposed allocator in Regulatory Rate Rider #3 for both OM&A costs, Exhibit G1, Tab 5, Schedule 1, Page 2, lines 13 to 16, OM&A costs would be the allocator used by Hydro One to allocate the amount amongst customer classes.

j. The rate application in this filing was based on an estimate of about $104 million for pension costs in 2008. The actual pension costs for 2007 were about $95 million. While the actual pension contribution is expected to be higher in 2008 as a result of higher base pensionable earnings, the expectation is that the deferral account will be in an over-recovery (liability) position. See response to (e) above.

Ontario Energy Board (Board Staff) INTERROGATORY #124 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2

Hydro One is requesting for a new deferral and variance account related to the OEB Cost Differential.

a. What is the regulatory precedent for the collection of each of the identified costs proposed to be included in this deferral account?
b. What is the justification for this account?
c. What account number does Hydro One propose to use in the USoA?
d. What are the journal entries to be recorded?
e. If the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?
f. What new or additional information is available that would improve the Board's ability to make a decision on this request?

Response

a. The regulatory precedent can be found in a letter from the Board dated December 20, 2004 to electricity distributors. In that letter the Board authorized the establishment of a deferral account to record OEB cost assessments that may not be included in rates. Hydro One Distribution established the deferral account pursuant to the Board letter and received approval for recovery of costs recorded in the deferral account in RP-2005-0020 (EB-2005-0378) Hydro One Networks Inc., Electricity Distribution Rates 2006. In that same decision, the Board approved Hydro One Distribution's request for establishment of a new variance account for the OEB Cost Assessment Differential.

b. Hydro One Distribution budgets for costs associated with the annual OEB assessment, intervenor awards, and OEB-initiated studies. However the actual amounts of these payments are subject to variability and are outside of the Company's control. As such, it is appropriate that any differences between budgeted and actual costs be tracked and recovered from or paid back to customers.

c. Hydro One Distribution proposes to use USofA 1508.

d. The journal entry will be as follows, if the amount of the payment to be made is greater than the amount approved in rates:

Debit: Regulatory Asset OEB Cost Assessment (Balance Sheet Account),
Credit: OM&A Program Account recording the payment

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The amount of the journal will be calculated as the difference between the actual annual OEB Cost Assessments, intervenor cost awards, and costs associated with OEB-initiated studies and the amount for these expenditures approved by the OEB as part of 2008 Distribution Rates.

e. Costs or fees would only be booked to this account once they are known.

f. The support and precedent for this request is provided in the Exhibit F1, Tab 3, Schedule 1 and in the response to (a) above.

Ontario Energy Board (Board Staff) INTERROGATORY #125 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2
Hydro One is requesting for a new deferral and variance account for the Bill Impact Mitigation.

a. What is the regulatory precedent for the collection of the difference between the Hydro One requested revenue requirement and the distribution rates from the application of the Cost Allocation for Electricity Distributors report in this proposed deferral account?
b. What is the justification for this account?
c. What account number does Hydro One propose to use in the USoA?
d. What are the journal entries to be recorded?
e. Please provide a continuity schedule of the incentive rate years outlining expected transactions into this variance account if approved.
f. What new or additional information is available that would improve the Board's ability to make a decision on this request?

Response

a. Please see Exhibit F1, Tab 3, Schedule 1, page 2, lines 11 to 17 for regulatory precedent.

b. The justification is to limit bill impacts to customers to a maximum of 10% on total bill.

c. Hydro One is proposing to use account 1508.

d. The journal entries are Debit to Regulatory Assets / Credit to Revenue.

e. Hydro One is expecting that $2.5M would be added to this account every year, beginning May 1, 2008. An illustrative continuity schedule for the period from May 2008 to April 2011 is provided in the table below:

$ millions	May 2008	Dec 2009	Dec 2010	Dec 2011	Apr 2011
Principal	0.0	1.7	4.2	6.7	7.5
Interest	0.0	0.0	0.2	0.4	0.6
Total	**0.0**	**1.7**	**4.3**	**7.1**	**8.1**

f. There is no new information.

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COST ALLOCATION OF REVENUE REQUIREMENT

This exhibit presents an overview of the process to allocate Hydro One Distribution related revenue requirement costs to Legacy, Acquired, and Sub-Transmission customer groups (including current Embedded LV customers).

1.0 INTRODUCTION

The 2008 revenue requirement of $1,067 million for Hydro One Distribution was derived in Exhibit E1, Tab 1, Schedule 1, and is attributed to the Retail, (Legacy and Acquired), and Sub-Transmission customers.

This revenue requirement is allocated to the proposed customer groups using the Cost Allocation methodology issued by the OEB on September 29, 2006 in the RP-2005-0317 proceeding. Hydro One modified the OEB methodology to reflect its unique circumstances related to the provision of an LV system and a very large number of rates. The modifications are detailed in Exhibit G2, Tab 1, Schedule 1, and are similar to the modifications applied in Hydro One's Cost Allocation Information Filing of January 15, 2007 as part of Proceeding RP-2007-0001.

2.0 APPORTIONMENT OF REVENUE REQUIREMENT

Hydro One used the OEB Cost Allocation Methodology to allocate the proposed $1,067 million revenue requirement to customer classes. The allocated revenue requirement was compared to the revenues that would be collected from customers at adjusted 2007 Distribution rates. The adjustment consisted of increasing the 2007 approved rates proportionally to recover the 2008 Revenue Requirement of $1,067 million. Revenue to cost ratios were then calculated. Revenue to cost ratios above 1 mean that the customer class is over-contributing and revenue to cost ratios below 1 mean that the customer class is under-contributing. The results of the cost allocation study are summarized in the Table below.

Table 1
Hydro One Cost Allocation Study Results

	UR	R1	R2	Seasonal	UGSe	UGSd	GS e	GS d	ST	DG	Street Light	Sent. Light	Total
Rev Req $M	66.0	240.2	390.3	83.6	9.3	16.8	111.1	105.4	27.4	0.4	8.1	8.0	1,066.6
Revenue at current rates $M	57.7	197.1	404.6	77.0	12.1	16.0	119.6	107.9	64.2	0.6	4.9	4.9	1,066.6
Rev/cost ratio	**0.87**	**0.82**	**1.04**	**0.92**	**1.29**	**0.95**	**1.08**	**1.02**	**2.35**	**1.63**	**0.60**	**0.62**	**1.00**

More details on the results of the cost allocation study can be found in Exhibit G2, Tab 1, Schedule 1.

3.0 TARGET REVENUE TO COST RATIO

Hydro One is proposing to use the revenue to cost ratio ranges recommended in the Board's report issued November 28, 2007 under proceeding EB-2007-0667, "Application of Cost Allocation for Electricity Distributors". The Board recommended revenue to cost ratios range from 0.7 for street lights to 1.8 for large commercial customers. Given that this is the first time that the OEB's cost allocation methodology is being used as a basis for determining distribution rates, the wider range of revenue to cost ratios proposed by the Board will reduce the potential bill impacts on customers whose distribution rates have to increase to closer reflect cost causality. The proposed range of revenue to cost ratios will result in those customer classes with a revenue to cost ratio above 1 continuing to cross-subsidize those customer classes with a revenue to cost ratio below 1.

Hydro One is proposing the following revenue to cost ratios for the various new proposed customer classes.

For the R2 Residential, General Service energy billed, and General Service demand billed customer classes, the current revenue to cost ratio is proposed to be maintained:

For the Distributed Generation customer class, the revenue to cost ratio is proposed to be set at 1.0 rather than the current 1.63 in support of Government policy to promote Distributed Generation in Ontario.

For Street Light and Sentinel Light classes it is proposed to increase the revenue to cost ratio from about 0.6 to 0.7. This is the lower end of the revenue to cost ratio proposed by the Board for this class of customers.

For the Urban General Service energy billed class it is proposed to reduce the revenue to cost ratio from 1.29 to 1.2. This is the higher end of the revenue to cost ratio proposed by the Board for small commercial customers.

For the Sub-Transmission class it is proposed to reduce the revenue to cost ratio from 2.35 to 1.15. This is the higher end of the revenue to cost ratio proposed by the Board for large users.

In order to recover almost all of the 2008 Revenue Requirement based on the revenue to cost ratios described above, the revenue to cost ratio for Urban Residential, R1 Residential, Seasonal Residential and Urban General Service demand billed customer classes will have to increase. The revenue to cost ratios for the Urban Residential, Seasonal Residential, and Urban General Service demand billed customer classes are proposed to be set to 1.0. For the R1 Residential customer class, the proposed revenue to cost ratio is 0.88, which results in bill impacts that are considered to be the maximum that Acquired residential customers being harmonized to this customer class can sustain.

The proposed revenue to cost ratios result in Hydro One not being able to fully recover its 2008 proposed Revenue Requirement. The shortfall is estimated to be $2.5 million per year, which is the difference in the total proposed revenue requirement shown in Table 2 as compared to Table 1. Hydro One proposes to establish a variance account, as described in Exhibit F1, Tab 3, Schedule 1 to record this revenue shortfall for recovery at a future date from all customers.

Table 2
Proposed Revenue/Cost Ratio by Customer Class

	UR	R1	R2	Seasonal	UGSe	UGSd	GS e	GS d	ST	DG	Street Light	Sent. Light	Total
Proposed Revenue Requirement $M	66.0	211.4	404.6	83.6	11.2	16.8	119.6	107.9	31.5	0.4	5.7	5.6	1,064.1
Proposed revenue to cost ratio	**1.0**	**0.88**	1.04	**1.0**	**1.2**	**1.0**	1.08	1.02	**1.15**	**1.00**	**0.7**	**0.7**	1.0

*Revenue to cost ratios in bold show the proposed change

4.0 REVENUE TO COST RATIO EQUAL TO ONE

In response to feedback received during the stakeholdering process, Hydro One explored the impact of moving all customer classes to a revenue to cost ratio of 1. Table 3 shows the average impacts that would result from making this change. As shown in Table 3, the resulting average total bill impacts under a revenue to cost ratio of 1 is generally greater and could be as much as three times the impact under the proposed revenue to cost ratios. As a result, using a revenue to cost ratio of 1 for all customer classes would result in either unacceptable bill impacts or the need for an excessively long impact mitigation period.

Table 3
Impact to Customer Classes of Revenue/Cost Ratios

	Proposed R/C	Average impact %	R/C = 1	Average impact %
UR	1.0	3.4	1	3.4
R1	0.88	3.0	1	8.3
R2	1.04	1.0	1	(0.8)
Seasonal	1.0	9.7	1	9.7
UGe	1..2	(2.3)	1	(6.3)
UGd	1.0	0.3	1	0.3
GSe	1.08	0.5	1	(2.2)
GSd	1.02	(2.1)	1	(2.7)
DG	1	(29.0)	1	(29.0)
Street Light	0.7	5.0	1	21.7
Sentinel Light	0.7	25.0	1	118.1
ST	1.15	(4.7)	1	(5.0)

hazardous aspects of our jobs. It is necessary. As stewards of Ontario's transmission electricity system and the largest distribution system, we feel it would be irresponsible of us not to bring these people in in advance, while we still have the opportunity to coach and mentor them, so they can take over these jobs.

MR. BUONAGURO: Thank you.

I have some questions on the pension question, much to the chagrin of Mr. Clark, I'm sure.

MR. CLARK: I didn't give him that one.

MR. BUONAGURO: I can tell you it came from Mr. Harper, but I think it is somewhat benign, at least to them.

Exhibit C1, tab 3, schedule 2, appendix A.

MR. VAN DUSEN: Yes, I have that.

MR. BUONAGURO: Take a look at page 3. Could you confirm that this application is based on a total estimated pension contribution for 2008 of $104 million?

MR. VAN DUSEN: Yes, I can confirm that.

MR. BUONAGURO: Then at page 2, it talks about the allocation, and 31.7 percent of the 140 million goes to distribution.

MR. VAN DUSEN: Sorry, the number you're looking at, 31 did you say?

MR. BUONAGURO: 31.7 is the number I have.

MR. VAN DUSEN: I'm seeing a number of 56 million corporate pension costs charged to distribution in mine.

MR. BUONAGURO: Sorry.

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MS. McKELLAR: That's what I have.

MR. VAN DUSEN: I'm looking at page 2 of that exhibit and adding up the total OM&A and capital in association with the distribution system, and getting $56 million dollars, sir.

MR. BUONAGURO: Okay. It must have been a calculation error.

Well, we can say then $56 million of the total, then, so around 50 percent?

MR. VAN DUSEN: Roughly.

MR. BUONAGURO: Okay. And can you confirm that the application which includes these numbers was done prior to the completion and filing of the pension evaluation.

MR. VAN DUSEN: It certainly was done before the filing of the evaluation.

MR. BUONAGURO: All right.

MR. VAN DUSEN: The evaluation which is filed attached to -- H1-76 was filed after our distribution application was filed; yes, that's correct.

MR. BUONAGURO: Okay. And interrogatory response H12-21 says that based on this evaluation, the required pension contribution for the years 2007, 2008 and 2009 is $95 million, total, I guess, per year.

MR. VAN DUSEN: Sorry, what was the reference to the interrogatory, please?

MR. BUONAGURO: H12-21.

MS. McKELLAR: I don't have it.

MR. VAN DUSEN: Just one second, please.

MR. BUONAGURO: Sure. It's on page 2, third full paragraph.

MS. McKELLAR: Have you got it? Thank you.

MR. VAN DUSEN: Sorry, my apologies. I have it now. Sorry, could you repeat your question?

MR. BUONAGURO: Sure. In this interrogatory response at page 2, third full paragraph it says:

> "The valuation report submitted to FSCO in September 2007 will establish a level of contribution of about $95 million for the three-year period 2007 through 2009."

MR. VAN DUSEN: Yes, that's correct.

MR. BUONAGURO: Okay. Does that mean that there's a difference in the numbers between the application and the evaluation of about $9 million per year?

MR. VAN DUSEN: Yes, there is.

Please let me take you, though, to response to Board interrogatory H, tab 1, schedule 123. In the response to part A:

> "Hydro One acknowledges the difference between the amount contained in our application and the amounts indicated by the new actuarial evaluation and as such Hydro One is requesting the deferral account."

Mr. Innis, in his appearance on panel 4, will be able to talk to the deferral account specifically, but the reasoning is straightforward. The application came in based on an older estimate. We have a newer estimate in a deferral account consistent with the Board's past practice on this has been requested.

MR. BUONAGURO: Okay. So -- which is all to say that if that holds up, then we'll be paying your rates, the actual number?

MR. VAN DUSEN: Yes, that's correct.

MR. BUONAGURO: Okay. Obviously I missed that interrogatory response.

I'm thinking back to the first day. Are there any other corrections to the application that you are acknowledging similar to that that we should know about?

MR. VAN DUSEN: This isn't a correction. This is a -- part of our original application, part of our filed material.

MR. BUONAGURO: What I mean is changes in numbers for various reasons. Like, for example, that would be a change in a number because new information came out that you are accepting rather than stumbling upon it like that which is partly my fault --

MR. ROGERS: There are no material changes that we're aware of that would affect the application. The application is what it is. There are no mistakes that I am aware of, of any significance. This is not a mistake, as you heard, it was clearly identified.

MR. KAISER: It's an update?

MR. ROGERS: Yes.

MR. VAN DUSEN: There are other deferral accounts and of course the disposition of the regulatory assets is part

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of panel 4. Mr. Innis will be able to talk about that. I believe there are two other deferral accounts in front of the Board for their consideration, as well. This is one of them, as part of our filed evidence.

MR. BUONAGURO: All right. Thank you.

MR. KAISER: If you're leaving that, can I just ask a question before you go to the next. On the chart you were just referring to C1, schedule 3, 2, this is where you had 45 million in pension costs for transmission, 56 for distribution.

I notice that the material says that you arrived at that allocation based upon pensionable earnings. So these are the actual salary figures, I take it, that you are using for the purpose of splitting the pension costs between the two businesses?

MR. VAN DUSEN: It's almost correct, Mr. Chairman. It has to do with estimated pension earnings for 2008, but, yes, we take a look at an estimate. As Ms. McKellar pointed out, we can do an estimate, at a high level, of the total salary and then an estimate of the total base pensionable earnings and therefore the -- then do an allocation between OM&A and capital.

MR. KAISER: Why do you split the pension costs between OM&A and capital? Is that because there's labour in each?

MR. VAN DUSEN: Yes. There is labour in each. Labour rates that we have had so much discussion on today are applicable to the appropriate OM&A work and the appropriate capital work as well. So it is appropriate that pension costs be attributable to both OM&A and capital work programs.

MR. KAISER: So I understand there are two allocation exercises. But the 104, in total pension costs those are real costs.

MR. VAN DUSEN: Yes, they are.

MR. KAISER: They're real audited costs?

MR. VAN DUSEN: Yes, sir.

MR. KAISER: Then you allocate it once between transmission and distribution, and then within each of those two groups between OM&A and capital?

MR. VAN DUSEN: That's correct, sir.

MR. KAISER: Okay, thank you.

MR. BUONAGURO: Thank you. I have some questions on Cornerstone.

First, in response to earlier questioning, you talked about benefits of the project which would occur or are supposed to occur in 2009 and 2010 during the IR period.

And the answer to the question how would they be captured by ratepayers seems to be they will be captured as part of the IRM process. Did I understand that correctly?

MR. CURTIS: Yes, you did.

MR. BUONAGURO: So for example, when Hydro One applies for 2009 IRM adjustment -- assuming that is what happens -- part of the application will illustrate the benefits associated with Cornerstone for that rate period, the 2009 rate period. Then that will be an adjustment to your base

PENSION COSTS

1.0 PENSION COSTS

Hydro One Networks is a participant in the Hydro One Pension Plan ("the Plan"). The Plan is a contributory, defined-benefit pension plan whose members comprise represented employees of the Power Workers Union ("PWU"), the Society of Energy Professionals ("Society"), MCP employees, pensioners who were employees, and pensioners who are beneficiaries of employees or pensioners.

The Board has previously allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). As well, in April 2006, the OEB in its Decision with Reasons, approved full recovery of Distribution pension costs included in OM&A (RP--2005-0020/EB-2005-0378).

Pursuant to the Inergi outsourcing agreement (see Exhibit C1, Tab 2, Schedule 6), Hydro One Networks is also required to pay, directly to Inergi, a predetermined estimate of Inergi's annual current service pension cost in each year for each of the ten years of the outsourcing.

The Hydro One pension cost allocated to Hydro One Networks is based on the ratio of base pensionable earnings for Hydro One Networks' staff, as compared to the total base pensionable earnings for all of Hydro One employees. The method of allocation of the pension cost and the Inergi annual pension charge is consistent among all shared services costs, for operating and capital costs, and is consistent with the methodology reviewed during RP-2005-0020/EB-2005-0378 and EB-2006-05-01.

For the Distribution business, the annual charge to be recovered through rates is estimated as follows:

Annual cash pension cost (millions)
(may not add due to rounding)

2008	Transmission		Distribution		Other		Total	
Corporate Pension Costs								
OM&A	$	27	$	33	$	3	$	63
Capital	$	18	$	23	$	-	$	41
	$	45	$	56	$	3	$	104
Inergi Annual Pension Charge								
OM&A	$	2	$	4	$	-	$	6

2.0 ACTUARIAL CALCULATION

The most recent actuarial valuation for the Hydro One Plan was as at December 31, 2003. In September 2004, Hydro One filed this actuarial valuation with the Financial Services Commission of Ontario (FSCO), which was reviewed during RP-2005-0020/EB-2005-0378. The valuation showed that the Plan had a deficit of $167 million, on a going-concern basis. The required contribution for the Hydro One companies was set at $81 million starting in 2004, variable based on the level of base pensionable earnings. Of this amount, about $60 million represented annual current service costs, and the remaining portion represented special payments over 15 years required toward the going-concern deficiency, and commuted value top-ups.

In accordance with applicable regulations, Hydro One has made all required contributions since January 1, 2004.

Hydro One's next actuarial valuation will be prepared as at December 31, 2006 and will be filed with FSCO in September 2007. The valuation will depend on investment returns, changes in benefits, and actuarial assumptions.

Pension costs for 2008 are estimated at $104 million respectively. These pension costs were derived from estimates prepared by Mercer Human Resource Consulting LCC ("Mercer"), the Plan's actuary. The December 31, 2003 membership data and September 30, 2005 assets were extrapolated to December 31, 2006.

The estimated $104 million contribution in 2008 is comprised of $74 million in current service cost and $30 million in unfunded liability payment. The change from the $81 million contribution estimate in the 2003 actuarial valuation, or $23 million, is due to:

Impact of liability and service cost increase due to assumption changes	$20 million
Increase in current service cost reflecting staff growth	$ 8 million
Impact of asset gains	($5) million
	$ 23 million

Going concerns assumption in the 2003 actuarial valuation and in Mercer's estimate for 2007 are the same except inflation was raised from 2.25% to 2.50%, consistent with market conditions. The inflation estimate is based on the spread between the yield on long-term Government of Canada Bonds and Government of Canada Real Return Bonds. This spread increased by 0.25% between December 31, 2003 and October 31, 2005 (the latest available yields at the time the estimate was prepared). The yield spread at July 31, 2006 is consistent with the yield spread at October 31, 2005.

The staff growth reflected in the increase in current service cost supports the requirements of the work program.

The short-term investment experience in 2004, 2005, and 2006 exceeded the long-term discount rate used to calculate pension plan liabilities at December 31, 2003. This investment experience in 2004, 2005 and 2006 is expected to contribute to a reduction in projected contribution requirements, starting in 2007, from the costs shown in this evidence. However, updated costs, and all other relevant assumptions, have not been finalized at the time this evidence has been prepared.

During 2007, actual contributions have commenced based on an estimated $100 million contribution level, consistent with estimates provided in RP-2005-0020/EB-2005-0378. Actual contribution requirements in 2007 and 2008 may differ that will depend on final membership data, plan assets and economic assumptions used in the actuarial report filed as at December 31, 2006. The difference between the estimated and actual pension costs will be tracked in a variance account (see Exhibit F1, Tab 3, Schedule 1).

3.0 PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One is the Plan sponsor and administers the pension assets and obligations of the Plan. As of December 31, 2006, the Plan had a reported net asset value of $5,199 million and about 11,680 members. One-third of the Plan's members are active. The remaining Plan members are inactive, either retired or beneficiaries of retirees. The Plan governance was reviewed during RP-2005-0020/EB-2005-0378.

The Fund has consistently outperformed market indices. In the period from June 29, 2001 (the Fund's inception) to December 31, 2006, the Fund return was 9.54% and the Fund outperformed its target return number by 0.71%.

In addition, Fund performance has been favourable relative to that of other pension funds. Specifically, the Fund has a 20th percentile rank since inception.

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Accounting Standards Board AcSB CNC Conseil des normes comptables

Accounting Standards Board Decision Summary August 22, 2007

This summary of Accounting Standards Board (AcSB) decisions has been prepared for information purposes only. Decisions reported are tentative and reflect only the current status of discussion on projects, which may change after further deliberations by the AcSB. Decisions to publish Handbook material are final only after a formal ballot process.

For more detailed information on AcSB projects, including the decisions summarized below, please refer to the project summaries under Projects , which will be updated within the month following an AcSB meeting.

Rate-Regulated Operations

The AcSB considered the comments received on its March 2007 Exposure Draft, "Rate-Regulated Operations," and decided to:

- remove the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, pertaining to the application of that Section to the recognition and measurement of assets and liabilities arising from rate regulation;
- amend Section 3465, *Income Taxes*, to require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to future customers; and
- make these changes applicable prospectively to fiscal years beginning on or after January 1, 2009.

The AcSB also decided not to withdraw:

- the existing guidance relating specifically to rate-regulated operations in Section 1600, *Consolidated Financial*

Statements, Section 3061, Property, Plant and Equipment, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*; and
- AcG-19, *Disclosures by Entities Subject to Rate Regulation*, but to make consequential amendments to the Guideline as a result of the above changes.

The changes to Sections 1100 and 3465 will result in consistency between all Handbook Sections providing guidance relating specifically to rate-regulated operations, and the corresponding guidance under US GAAP.

The AcSB believed there was benefit to removing all Handbook recognition and measurement guidance relating specifically to rate-regulated operations prior to the adoption of IFRSs for publicly accountable enterprises, as was proposed in the Exposure Draft, and noted that the decisions summarized above may not have a much different effect on practice than the Exposure Draft proposals. At the same time, it acknowledged the concerns expressed by respondents about the ability of Canadian entities to rely on US GAAP in this area, and to influence the development of any future IFRS guidance on rate-regulated operations, once the Handbook guidance had been removed. The AcSB noted the high degree of support expressed by respondents for retaining AcG-19 during the transition period.

The AcSB also noted that:
- respondents appeared focused on the current uncertainty about whether the accounting prescribed by FASB Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71), and Handbook Sections with recognition and measurement guidance relating specifically to rate-regulated operations, is compatible with IFRSs, and therefore, what will transpire upon changeover to IFRSs; and
- it has brought this issue to the attention of other national standard setters and the IASB, and continues to follow up on it.

The AcSB decided that the final Background Information and Basis for Conclusions for this project would not express any views of the AcSB regarding this issue or the status of FAS 71 as an "other source of GAAP" within the Canadian GAAP hierarchy.

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MR. BUONAGURO: Okay, thank you.

I think I can squeeze in one more topic before 4:30. I was asking the previous panel about pension costs, and I have excerpted the transcript reference, page 13 of the book. It is from the July 10th transcript. Sorry. Yes, page 13.

Sorry. No, that's wrong. It's 14 to 16.

Basically, I went through the pension costs, and if I can summarize, in the application, the total figure for the pension costs was $104 million and the updated figure was $95 million.

MR. INNIS: The 104 million is what is in the filed evidence, and 95 would be the valuation from the financial evaluation of the pension fund.

MR. BUONAGURO: I understood from that conversation from the filing that you have a deferral account that is supposed to track the deviation and, in fact, that would be one type of deviation you would be tracking?

MR. INNIS: That is correct.

MR. BUONAGURO: Okay. Now, I think this was left off on the transcript, and I think it was partially referred to you in terms of deferral account treatment, so perhaps I could ask you the question.

As a result of that update, would the amount that goes into rates in the 2008 be the 104 million or the 95 million based on the new evidence, the 95 million?

MR. INNIS: I can address that. The 104 million is what is in rates for 2008. Of that 104 million, only a portion of that is attributed to the distribution business. The 104 is a full Hydro One amount.

So a portion of that would be based on the -- it would be attributed to the distribution business, the rates.

MR. BUONAGURO: I understand that. When I say 104, I always mean the portion that is attributable to DX for distribution.

MR. INNIS: Okay.

MR. BUONAGURO: You had 104 when you applied for it. You now know the number, according to your evaluation, is going to be 95. You're proposing a deferral account to track the difference, in any event, so presumably whatever number you use, you are going to be held whole; right?

MR. INNIS: Yes, that's correct. If I can just clarify the 95, that was a number based on an estimate for 2007. So what we're expecting is that the actual 2008 experience will be greater than that. There is an adjustment for base pensionable earnings.

So the number will be somewhat higher, we expect, than the 95. So let's assume for the sake of discussion that number is $98 million. So what we would be doing, then, is tracking the difference between the 104, which is currently in rates, and our actual pension costs, the portion that is attributed to distribution, and we would be putting those in a deferral account.

If the value is less than what we have in rates, then we will track that and we will be giving that back to customers at a future date.

MR. BUONAGURO: Now, particularly since this is a deferral account treatment and they're going to be trued up in any event, why wouldn't you put into rates for 2008 the more accurate figure?

MR. INNIS: We don't know what the actual rates will be for 2008 at this point in time.

MR. BUONAGURO: Sorry, you don't know that the actual will be 98 million, for example?

MR. INNIS: We don't know, no. I said as an example, but we don't know what that would be.

The 2008 pension expense will be a function of the base pensionable earnings incurred in 2008. So it is not until the end of the year that we would know the actual amount.

MR. BUONAGURO: So why is 104 a better placeholder than, say, 95?

MR. INNIS: 104 million was the estimate prior to receiving the valuation.

MR. BUONAGURO: Now you have the evaluation, which has refined it.

MR. INNIS: And the valuation is 95. We expect that number to be a bit higher than the 95.

It could be upwards of 104 perhaps, as well. So rather than chase the number, we have locked in on the 104, and the deferral account will be able to true up the difference once the amount for 2008 is known.

MR. BUONAGURO: Just one last question on that. If you stick with the 104, it sounds like you are almost guaranteed, unless something really weird goes on, to over-recover in rates, based on the evaluation you just -- we have been talking about.

MR. INNIS: Not necessarily.

MR. BUONAGURO: Not necessarily?

MR. INNIS: We would have to look at what our experience would be for 2008, and so I couldn't say for sure that we'd be over-recovering.

I think it is important to keep in mind that the 104, as I mentioned, is a Hydro One number.

The portion that gets attributed or that is embedded in rates for 2008 would be approximately 30 percent of that. So we're talking about 30 percent of a difference between 104 and whatever the final number is.

In one of our undertakings, we estimate that amounts to be about $1.5 million, is what we would expect to be in that account.

MR. BUONAGURO: Okay.

MR. INNIS: But that, once again, is an estimate. We don't have the 2008 experience yet. We would have to do that calculation at the end of the year.

MR. BUONAGURO: Is that a good time to break?

MR. KAISER: Yes. We will adjourn until 9:30 Thursday.

MR. BUONAGURO: Thank you.

--- Whereupon the hearing adjourned at 4:32 p.m.