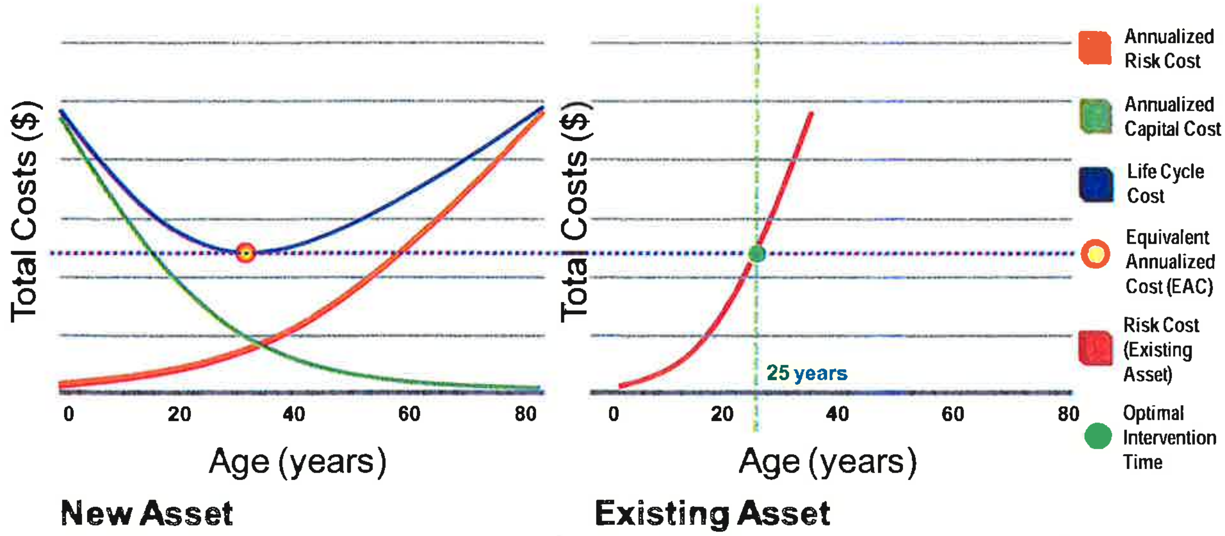

FIGURE 2: LIFE-CYCLE COSTING ANALYSIS (WHERE OPTIMAL INTERVENTION TIME IS A KEY INPUT USED WHEN CALCULATING THE STEADY STATE OF THE DISTRIBUTION SYSTEM AS PER RISK-BASED OPTIMIZATION APPROACH)

By applying this risk-based optimization approach to the broader population of major distribution assets across the system – such that the actual timing of asset renewal investments is, on average, aligned to the economic end-of-life criteria – a capital investment approach can be produced that allows for a optimal steady state to be achieved. Maintaining a steady state investment program is the most prudent approach to system investment, as it ensures that, on average, total life cycle costs of the assets across the system are minimized.

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The first deliverable in this review process – the derived capital investment approach for the five-year planning horizon from 2015 onwards to 2019 – can be broken down into three areas of investment as illustrated in Figure 3 and further detailed below.

D1.2 Asset Management Process Overview

This section outlines the major elements of Toronto Hydro's AM process, the inter-relationships between these elements, and the key inputs and outputs between these elements.

As illustrated in Figure 1 below, the AM process consists of five elements: (i) the planning process itself; (ii) the enterprise systems that support both the planning process and decision-support systems; (iii) the decision-support systems; (iv) the produced Distribution System Plan; and (v) measurement and enhancement activities that are conducted during the term of the CIR filing period (2015-2019).

The first element – the planning process – can be further subdivided into three stages:

- Long-term planning
- Short-term planning
- Maintenance planning

Long-term planning involves the development of a capital investment approach, execution strategy and associated investment spending levels, derived from long-term system studies and current-state assessments of the distribution system, which ultimately allow for the production of capital investment programs targeting prioritized assets and issues. This long-term planning process is further discussed in Section D1.2.1, with specific details on the process elements provided in Section D3.2.1.

Short-term planning involves the development of discrete projects that intervene upon prioritized assets and issues identified within the long-term investment programs. These projects are scheduled based upon system, resource and external constraints, and are executed accordingly. Project development, scheduling and execution result in further refinement and finalization of the investment spending levels for each capital investment program. The short-term planning process is further discussed in Section D1.2.2, with specific details on the process elements provided in Section D3.2.2.

Maintenance planning focuses on extracting the maximum value out of Toronto Hydro's distribution system assets through regular inspections, upkeep and repair activities. Maintenance planning also produces condition-related data which feeds back into enterprise databases and

While specific projects may change in scope, cost and timing during the CIR period, the utility has confidence that, over the course of the five-year planning horizon, the overall work program presented in the DSP can be executed as described. Prudence dictates that Toronto Hydro must retain the flexibility to execute an optimal mix of work in each given year. It is not possible to predict the specific work that will comprise Toronto Hydro's execution work program in 2019, but the utility can be certain that, over the five years of the application, this level of work, as set out in the DSP programs, is required.

IV. The proposed capital program ultimately delivers long-term value for customers

As discussed in part I of this section, the pace of investment during the 2015-2019 period is driven by system needs. The underlying need and establishment of pacing is described in detail in Toronto Hydro's asset management policy and processes[13] and in the capital expenditure plan.[14] At a high level, the long-term objective of Toronto Hydro's asset management policy is to achieve an optimal "steady-state", in which the number of assets that are past their economic end-of-life (explained below) is minimized. When the system is in that theoretical steady state, the total operating (or lifecycle) costs associated with the broader in-service asset population are minimized, meaning that customer value is maximized.

The concept of a steady state is based on Toronto Hydro's risk-based optimization approach to investment planning, which relies largely on use of the utility's Feeder Investment Model ("FIM") and other age and condition based information. Using these tools, Toronto Hydro determines the optimal asset renewal timing based on the economic end-of-life criteria for each asset. An asset reaches its economic end-of-life when the risk cost of continuing to operate the asset, which increases over time, becomes equal to or

[13] Exhibit 2B, Section D.
[14] Exhibit 2B, Section E.

THESL has consistently applied FIM to proposed renewal investments, which should result in least cost investment choices based on end-of-life economic evaluation criteria. The FIM results, coupled with other critical replacements THESL has identified, indicates up to a $2.5 billion backlog of assets exists for 2015 with another $1.55 billion for the remaining four years for a total of about $4 billion that is justified based on DSP economic end-of-life criterion. However, proposed spending for asset replacement over the five-year rate period is much less, reflecting a desire to balance risk and cost via paced spending.[5] The validity of the levelized approach is supported by THESL's reliability metric projections, which indicate proposed spending will maintain or improve system performance up to 2019.

Reliability Projections (RP)

The RP is an important process and set of analyses THESL uses to predict the reliability benefits associated with proposed upgrades and renewal replacements, including the impact on reliability for reinforcement and replacement options.[6] This capability is important, as the accuracy of the RP is contingent upon ACA data and predictive methods that quantify reliability impacts over time, including accelerated degradation for "do nothing" or "run to failure" strategies.

Databases

THESL relies on several data bases, collectively referred to as its Enterprise system, for use in its planning process and decision support tools described above. It includes asset records and condition data contained in THESL's Ellipse data base, a system commonly used by utilities for tracking and recording of maintenance and performance data. Similarly, the AM/FM GIS contains diagrams and feeder attribute data needed for planning, design and construction of the distribution system. It also provides requisite links or inputs to GEAR, and plant record keeping systems. The reliability data base provides failure history and cause code information needed to assess risk factors and the extent to which candidate solutions will impact reliability, safety and performance. As noted in our ACA review, THESL reports that the accuracy and quantity of data stored has risen over the past several years, commensurate with increases in sample size and quantity of information collected.

Feeder loadings are continually read and downloaded from the SCADA system and captured in a Feeder Loading Information System (FLIS) to provide information distribution planners use to conduct short- and long-term capacity studies. The data also ensure distribution simulation studies of feeder performance and operation are based on accurate loading data. This process is similar to those applied by most utilities to evaluate capacity alternatives and proposed spending.

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[5] Replacement spending of up to $4 billion over five years also would create disproportionate and unacceptable rate increases.

[6] In the absence of proposed spending programs, reliability would degrade to a SAIFI of 1.99 and SAIDI of 1.50.

If Toronto Hydro were to continue at the proposed annual average pace of investment beyond 2019, the system is forecasted to reach steady state by approximately 2037. This paced approach has the advantage of more predictable and tolerable bill increases during the 2015-2019 period and alignment with Toronto Hydro's immediate execution capacity. The paced strategy also helps to ensure more predictable bill impacts and system performance beyond the achievement of steady-state, due to the more gradual or dispersed approach to clearing the backlog of end-of-life assets.

3. STRUCTURE AND COMPLIANCE OF TORONTO HYDRO'S DSP

Toronto Hydro has organized its 2015-2019 Distribution System Plan ("DSP")[15] in a manner consistent with Chapter 5 of the Filing Requirements. Toronto Hydro has worked to provide DSP content that aligns with the spirit of the RRFE Report, as expressed through the Chapter 5 Filing Requirements, and that allows the OEB to evaluate all aspects of the utility's detailed and integrated five-year capital plan within the context of this Customer IR application. Key features of the DSP include the following.

- The five major sections of Toronto Hydro's DSP adhere to the organizational structure outlined in sections 5.2 and 5.3 of Chapter 5. This includes:
    - **Section A**: DSP Overview
    - **Section B**: Coordinated Planning with Third Parties
    - **Section C**: Performance Measurement for Continuous Improvement
    - **Section D**: Asset Management (AM) Process
    - **Section E**: Capital Expenditure Plan

[15] Exhibit 2B.

feeder, the entire feeder and the customers on that feeder would experience an outage until the failure is resolved. Looped-connected feeders have inter-feeder distribution tie points. Should an asset failure occur at either the distribution or station levels, power system controllers can perform sectionalizing and restore parts of the system by either remotely controlling Supervisory Control and Data Acquisition (SCADA) enabled switches, or directing field crews to perform manual switching on the switches that are strategically positioned along the feeder trunk circuits. This allows load to be restored using available capacity in adjacent feeders and or stations. In general, feeders in the Horseshoe area have inter-feeder tie points, while feeders in the central core do not.

Toronto Hydro continues to manage its aging infrastructure and is in the process of renewing its assets to prevent system performance degradation. Approximately 26% of Toronto Hydro's assets are at the end of useful life and an additional 7% expected to reach end of useful life by the end of the decade.

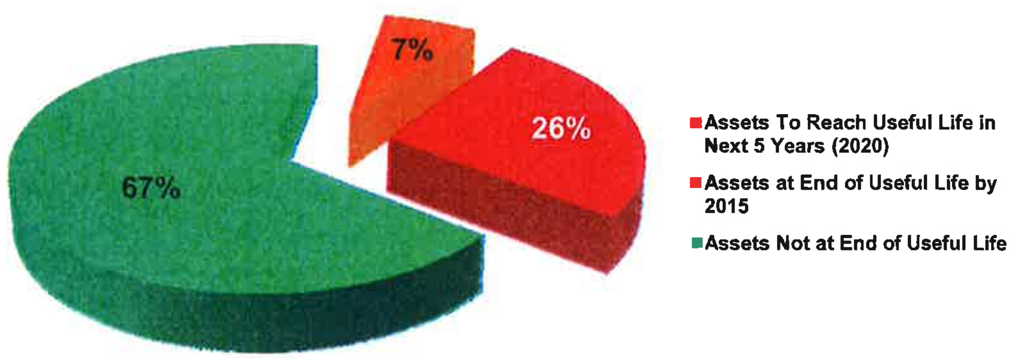


FIGURE 7: ASSETS PAST USEFUL LIFE DEMOGRAPHICS - 2015

Toronto Hydro is not the only utility in Toronto facing this "aging infrastructure" problem. For instance, Toronto Water and Sewage has infrastructure that is over 80 to 100 years old, with 17 presence of which would have been identified by the Predictive Maintenance task of Dissolved Gas Analysis.

Corrective Maintenance can also be required as a result of an unplanned system event or emergency. For example, a faulted section of underground cable that had been isolated from the system during an emergency response would be unearthed and replaced as a corrective maintenance action. For additional information, please see Exhibit 4A, Tab 2, Schedule 2.

D3.2.4 Emergency Maintenance

This type of maintenance involves the urgent repair or replacement of equipment that has failed or is in imminent danger of failure, in order to either restore or maintain power. This type of maintenance may also involve an immediate response to a safety or environmental hazard. It emphasizes safe and prompt response to restore service or prevent a service disruption. An example of Emergency Maintenance would be restoration of service to customers that have lost power due to a broken tree branch on the overhead lines. Exhibit 4A, Tab 2, Schedule 2 of the CIR evidence provides further information in this regard.

D3.3 Business Case Evaluation (BCE) Approach

Toronto Hydro uses the FIM to determine optimal intervention timing on an individual asset or the optimal timing for the replacement of a set of assets together. In addition to determining the optimal intervention timing for individual assets, FIM provides a quantification of the estimated risk based benefits of executing a program.

A BCE cannot be produced for capital investment programs which are not "dynamic" in nature (i.e., where discrete assets to be intervened upon and/or specific locations where new assets are to be installed cannot be identified, as explained in Section D3.1.1.3).

There are two types of business case evaluations based on program type that are used to estimate the benefits of a capital investment program:

- Avoided Risk Cost – Capital investment programs with like-for-like renewal of assets
- Cost of Ownership – Capital investment programs with non-in-kind intervention

D3.3.1 Avoided Risk Cost

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

e) Please explain how the end-of-life for the asset is combined with the Health Index for the asset to determine that a particular asset should be replaced;

f) For the asset reference 2 it is stated at page 2 that "By 2015, an estimated 51.6% of in-service station power transformers will be beyond their expected useful lives of 45 years…" Please indicate:

   i) The depreciation life of these transformers for accounting purposes.
   ii) The population of transformers under consideration and how many transformers are represented by the 51.6%.
   iii) The sensitivity of the data, by determining what percent (and how many) of the transformers would be beyond their expected useful lives if the useful life had been calculated as 50 years.

RESPONSE:

a) Please see Appendices A, B and C to this Schedule.

b) The end-of-useful life for an asset, also known as useful life or mean life of the asset, is determined by identifying the exact mid-point between the minimum useful life ("UL") and maximum UL as defined by Kinectrics within their "Useful Life of Assets" report, which was filed in the EB-2010-0142 application (Exhibit Q1, Tab 2). For Stations Power Transformers, the minimum UL is 32 years and the maximum UL is 55 years. Therefore, the exact midpoint would be 43.5 years, rounded up to 44 years, which represents the statistical mean or useful life of the asset in question. In this instance, the Stations Power Transformer Renewal program references the Typical UL value provided within the Kinectrics report of 45 years, since this value is very close to the statistical mean or useful life value.

the distribution system. In order to determine a life cycle cost, both the estimated risk cost and the replacement cost of an asset are annualized, as shown in Figure 4. The life cycle cost of the asset is then the simple sum of the annualized risk and annualized capital cost. The annualized capital cost is the cost of replacement annualized over its projected life. As shown in Figure 4, the minimum point of the life cycle cost curve, the Equivalent Annualized Cost (EAC) point, defines the life cycle at which the lowest operating cost is incurred and thus the optimal life cycle for a new asset.

By extending the EAC point determined for a new asset to the existing asset within the system (which shares the same configuration), the optimal intervention time (OIT) for that particular asset can be determined, which is detailed in Figure 4.

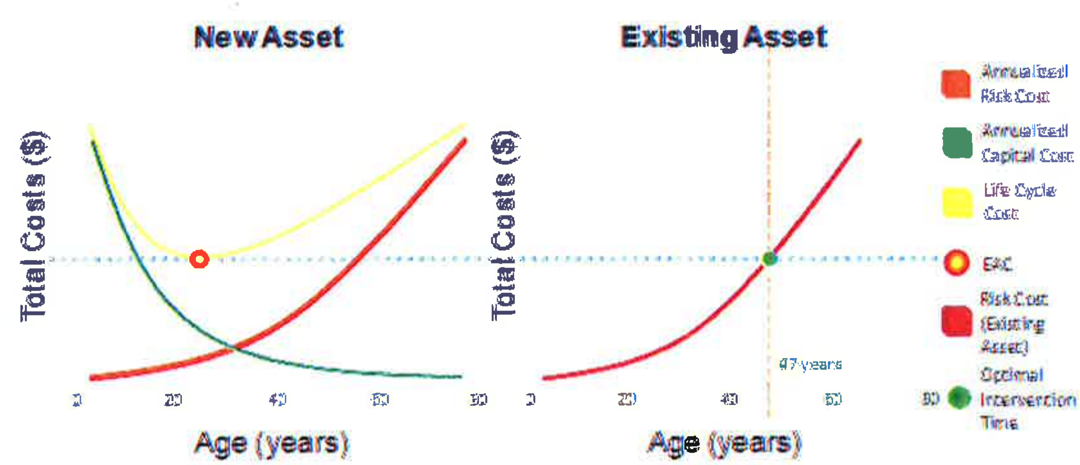


FIGURE 4: TYPICAL EXAMPLE OF ESTABLISHING THE OPTIMAL INTERVENTION TIME FOR AN EXISTING ASSET

Therefore, by using both the probability of asset failure and the impact to both Toronto Hydro and its customers upon asset failure, the FIM determines a risk cost for a particular asset. Comparing this cost against the capital cost of replacement, the OIT for each asset is established. Thus, the FIM allows Toronto Hydro to evaluate major asset classes within its system and determine a replacement program for each of these asset classes based on a risk mitigation approach.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

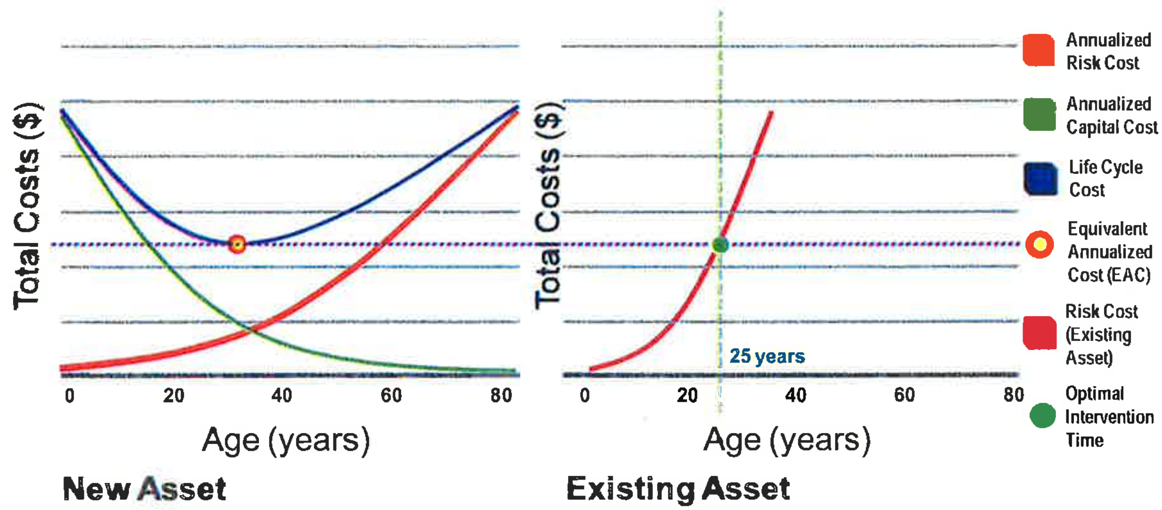
f)

i) For accounting purposes, Toronto Hydro uses a depreciation life of 32 years. This depreciation life was adopted January 1, 2011, based on the independent detailed review of useful lives conducted by Kinectrics. Refer to Exhibit 4B, Tab 1, Schedule 1 for background information on Toronto Hydro's depreciation and amortization policies. The 32 years depreciation life was selected for accounting purposes to align with the lower-end expected life identified by Kinectrics. This decision was made based on a commonly held industry perception that, due to a persistent incentive for suppliers to minimize cost, a newly designed and manufactured power transformer is not as robust and "over-engineered" as units built in the past. In development of the Distribution System Plan ("DSP"), Toronto Hydro decided to use the midpoint from the Kinectrics typical life study (45 years) because the DSP deals with lifecycle management of transformers that were designed and manufacturer multiple decades ago.

ii) The population of 248 power transformers is shown on page 16, line 22 of Exhibit 2B, Section E6.14. It is also shown at the bottom right corner of Figure 8 on page 17 of Exhibit 2B, Section E6.14. The 51.6% is derived by dividing the 128 transformers over 45 years old (typical useful life) by the total population of 248 transformers.

iii) For sensitivity analysis, if the useful life of a power transformer is changed to a theoretical value of 50 years old, then the percentage of power transformers exceeding the theoretical useful life would be 36.3% – equivalent to 90 power transformers.

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO



The annualized capital cost is derived from the cost of replacing the existing asset with the new asset – this cost has been annualized as a yearly cost across the life-cycle of the new asset. The minimum life-cycle cost – also referred to as the Equivalent Annualized Cost (EAC) – will be cross-referenced against the existing asset's risk cost curve – illustrated by the red curve on the right side of the figure – in order to determine the optimal intervention time, also known as the Economic End-of-Life of the existing asset. At this point, it becomes more cost-efficient to replace the existing asset than to continue operating it.

Comparison of Metrics Values

To compare the three metrics, Toronto Hydro has included a table in Appendix A that shows the Financial Useful Life for each of Toronto Hydro's distribution asset classes, along with the Useful Life and Economic End-of-Life for each of these classes where applicable and available. The Economic End-of-Life results are presented as a range of

MR. ZWARENSTEIN: And is there a source where I might investigate or where you might have provided some indication of the variability of the shape of these curves or the source of these curves so that we can investigate them? Because it might have a similar variability, as might the useful end of life.

MR. OTAL: To answer that question, we don't show any sort of variability or sensitivity to the economic end of life result, but I would say on a more broader basis, our a.m. planning process, because it is a multi-faceted approach, it's using a number of different decision support systems to arrive at our final decision-making accounts for those sensitivities and those variabilities when we're making the final investment decisions in our distribution system.

MR. ZWARENSTEIN: Would it be possible to get a precise curve for a particular asset so that we can understand that, the orange and the red graph for a particular asset, say power transformer, so that we can understand exactly how that appears?

MR. OTAL: Sure, we could provide a specific calculation for a specific power transformer asset.

MR. ZWARENSTEIN: That would be great, thank you.

MS. HELT: That'll be Undertaking TCJ1.15.

UNDERTAKING NO. TCJ1.15: TO PROVIDE A SPECIFIC CALCULATION FOR A SPECIFIC POWER TRANSFORMER ASSET.

MR. ZWARENSTEIN: So my next question relates to OEB Staff 37. And it's indicated that nine of the planned 21

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

f)

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TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. J1.15:

Reference(s):

To provide a specific calculation for a specific power transformer asset.

RESPONSE:

To illustrate the variability in actual asset level optimal intervention time calculations, Toronto Hydro has provided two contrasting examples for power transformers.

Figure 1 below shows the calculation for power transformer TR2 at High Level MS, which is discussed in the Power Transformer Renewal program – Section E6.14 of the DSP.

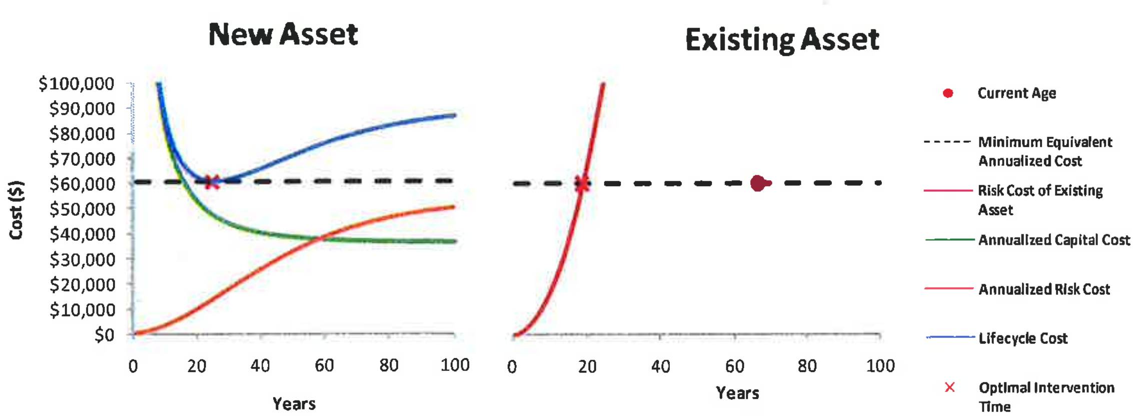


Figure 1: Lifecycle Cost for a Power Transformer – TR2 High Level MS

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

Figure 2 below shows the calculation for power transformer TR1 at Underwriters Crouse MS, which is also identified in the Power Transformer Renewal program.

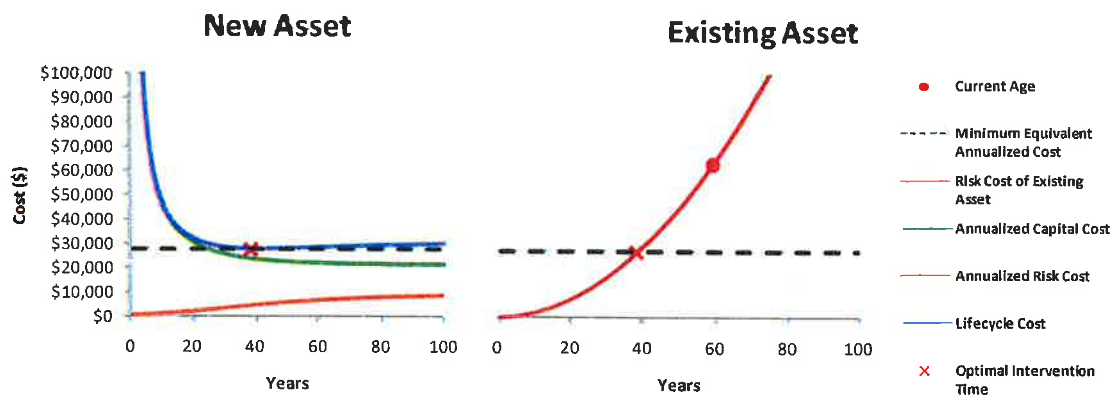


Figure 2: Lifecycle Cost for a Power Transformer – TR1 Underwriters Crouse MS

In order to determine the Optimal Intervention Timing for a power transformer, first the Annualized Capital Cost and the Annualized Risk Cost of a new transformer in the location of the exiting asset are developed, as shown by the green and orange curves in the two figures. The Annualized Capital Cost curve decreases as the lifecycle is extended because, as the transformer ages, the initial cost of purchasing and installing the transformer is amortized over a greater number of years.

The Annualized Risk Cost curve represents the amortized risk for a new asset. Figure 1 and Figure 2 show two possible scenarios for the risk costs of different power transformers. As shown, the Annualized Risk Cost curve of the transformer in Figure 1 is steeper than that of Figure 2. The difference in the Annualized Risk Cost curves in the two figures for the new power transformers is driven by their respective configurations within the system at the two locations. The transformer shown in Figure 1 supplies a

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

significantly larger load than the transformer in Figure 2. In the event of a failure, the transformer at High Level MS will impact a larger amount of load. As a result, the Annualized Risk Cost for the transformer at High Level MS, in Figure 1, is higher than the Annualized Risk Cost for the transformer at Underwriters Crouse MS, shown in Figure 2.

The difference in the risk cost curves due to the configuration at the two locations can also be observed for the existing power transformers, as shown by the red curve on the right in the two figures. In addition, the existing power transformer depicted in Figure 1 (TR2 at High Level MS) is older than the power transformer shown in Figure 2 (TR1 at Underwriters Crouse MS). Furthermore, the existing transformer in Figure 1 has a lower Health Index score than the one in Figure 2. Both of these factors contribute to an increased probability of failure and thus a steeper risk cost curve for the existing transformer in Figure 1 when compared to the one in Figure 2.

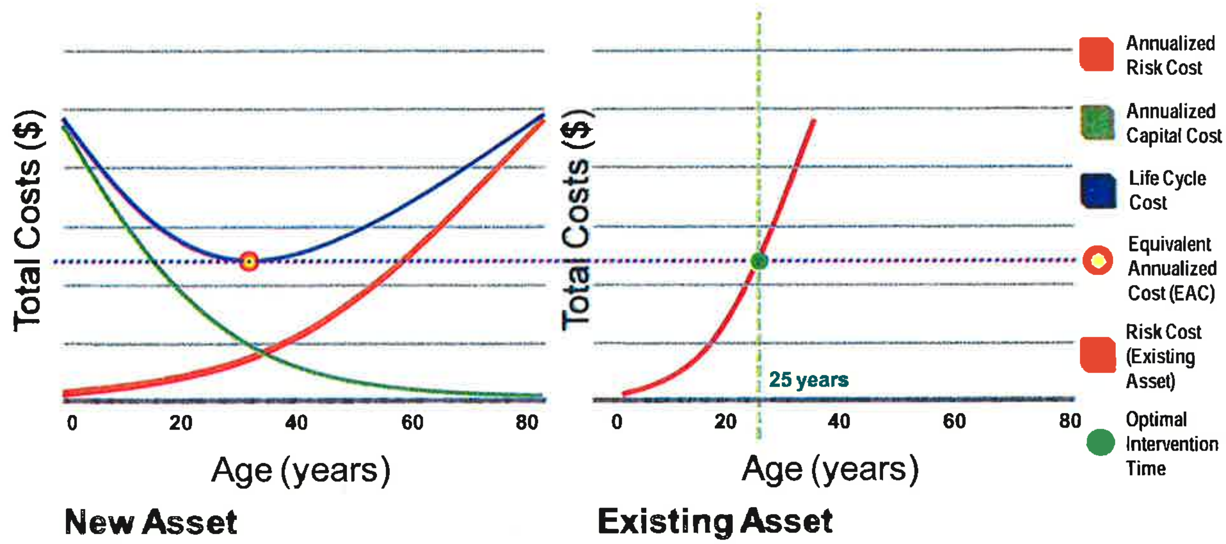
Both the Annualized Capital Cost and Annualized Risk Cost of the power transformer will have a significant impact on the economic end-of-life of these power transformers. The sum of the Annualized Capital Cost and Annualized Risk Cost results in the Total Lifecycle Cost of the asset, represented by the blue curve in the figures.

To determine the optimal lifecycle of a new transformer in a particular location, the minimum value of the lifecycle cost curve is taken, as shown by the red "X" in each figure. The minimum value for the lifecycle cost curve occurs at 25 years in Figure 1. This point defines the Minimum Equivalent Annualized Cost as shown by the dashed line. The intersection of this dashed line with the Risk Cost of the Existing Asset (red

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

curve) indicates the optimal age for replacement of the existing transformer given its age and condition, which determines the optimal intervention time for this asset.

In Figure 1, the optimal intervention time for the existing power transformer, shown on the right, is zero since this transformer is 68 years old in 2015, which is well past the intersection point of the risk cost curve for the existing asset and the Minimum Equivalent Annualized Cost line. Note that the risk cost curves for the existing power transformers, shown on the right in both Figures 1 and 2, are higher and steeper than the Annualized Risk Cost of a new power transformer due to the age and condition of the existing transformers.



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The first deliverable in this review process – the derived capital investment approach for the five-year planning horizon from 2015 onwards to 2019 – can be broken down into three areas of investment as illustrated in Figure 3 and further detailed below.

average of actual and forecasted spending over the three-year ICM period (2012-2014), and (iii) the proposed level of capital spending for each of the five years in the planning horizon.

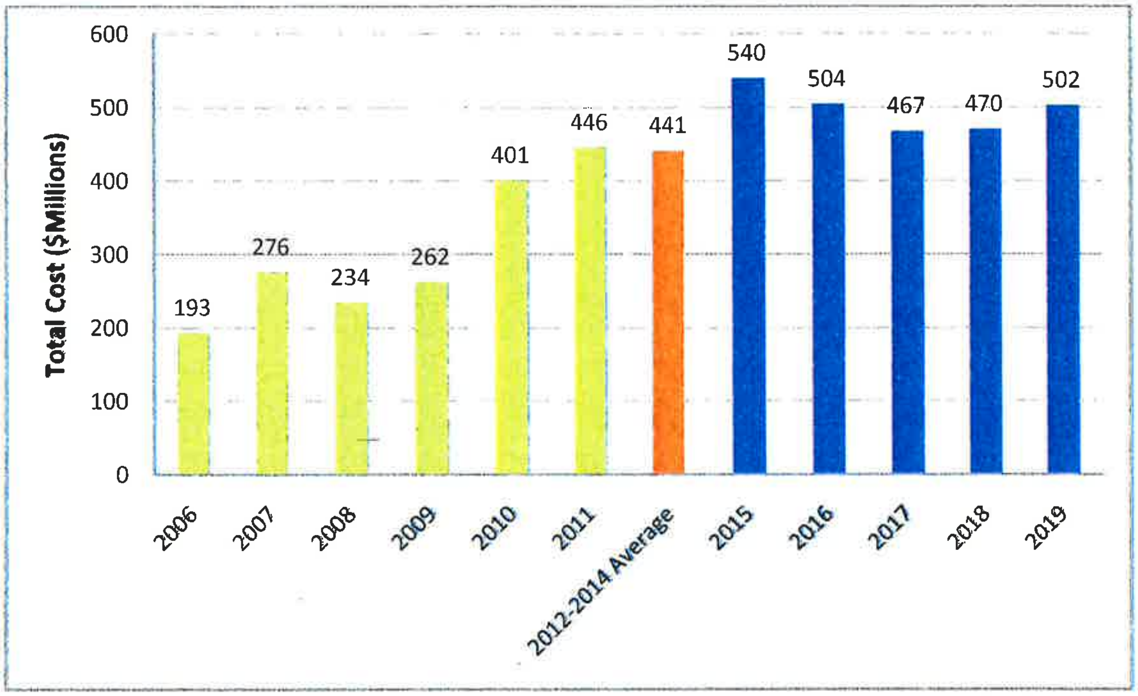

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Figure 1: Historical and Forecast Capital Spending (2006 – 2019) ($Millions)

As shown above, the average annual level of investment for the proposed capital program is comparable to the level of spending during the utility's 2012-2014 IRM/ICM period. This level of investment is required primarily to address the large and growing backlog of end-of-life and obsolete assets, while also addressing critical system challenges and operational needs at a pace and in a manner that moderates rate increases and is consistent with customer preferences. As demonstrated in the DSP, and as validated in the Navigant Report (Appendix B of this Schedule), this level of spending is the minimum level of investment that is appropriate during the 2015-2019 period given the

Further to the direct replacement of an asset, a number of assets have a refurbishment option which involves the replacement of non-standard accessories on overhead assets such as non-standard animal guards or lightning arrestors for overhead transformers and porcelain insulators on poles. The refurbishment option decreases the failure probability of the asset and thus reduces the risk cost of the asset. The FIM considers refurbishment as an option for optimal intervention and weighs the costs of refurbishment against the benefits from the decreased risk achieved by performing the work.

(ii) Asset Condition Assessment (ACA)

Toronto Hydro employs an ACA program to monitor the condition of various key asset classes within its system and produce a health index score to support project planning. The ACA program allows Toronto Hydro to produce a numerical representation of an asset's condition, taking into account key factors that affect its operation, degradation, and lifecycle.

For this rate-setting application, Toronto Hydro asked Kinectrics Inc. to assess the progress that Toronto Hydro has made with its ACA program since Kinectrics' most recent audit in 2012. Toronto Hydro has filed the 2014 Asset Condition Assessment Audit by Kinectrics Inc. as Appendix A to Section D of the DSP.

The basic approach used to develop the health index for each asset class is illustrated in Figure 5.

	Asset	Year	Very Poor		Poor		Fair		Good		Very Good	
			% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change	% Samples	Change
14	3ϕ OH Gang (Rem) Switches	2012	0.0%	0%	0.0%	0%	6.6%	9%	63.2%	14%	30.1%	-22%
		2014	0.0%		0.0%		15.4%		76.9%		7.7%	
15	SCADAMATE Switches	2012	0.0%	0%	0.0%	0%	1.7%	-1%	60.9%	-4%	37.4%	4%
		2014	0.1%		0.0%		1.1%		57.3%		41.4%	
16	Wood Poles	2012	2.5%	0%	7.7%	0%	46.0%	-2%	9.6%	-2%	34.2%	4%
		2014	2.3%		7.6%		44.1%		7.3%		38.6%	
17	ATS	2012	3.4%	-3%	23.7%	-7%	11.9%	20%	35.6%	-5%	25.4%	-5%
		2014	0.0%		17.0%		32.1%		30.2%		20.8%	
18	Network Transformers	2012	0.0%	0%	0.1%	0%	8.0%	8%	34.4%	7%	57.6%	-15%
		2014	0.0%		0.0%		16.4%		41.5%		42.1%	
19	Network Protectors	2010	0.0%	0%	0.0%	0%	0.9%	3%	27.2%	5%	71.9%	-8%
		2014	0.0%		0.0%		3.7%		32.3%		64.0%	
20	Network Vaults	2012	1.1%	1%	5.9%	3%	31.2%	41%	60.9%	-45%	0.9%	0%
		2014	1.7%		8.8%		72.4%		16.1%		1.0%	
21	Cable Chambers	2012	0.1%	0%	1.7%	0%	9.4%	1%	43.5%	7%	45.4%	-8%
		2014	0.3%		1.6%		10.8%		50.2%		37.2%	

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INTERROGATORY 37:

Reference(s): **Exhibit 2B, Schedule D, App. A, Kinectrics Report and THESL EB-2012-0064, Tab 4, Schedule B14**

On page 14 of the first reference, it is stated that 87% of the Oil KSO breakers have a 2014 classification of fair or worse condition leaving only 13% in good condition, a decline from the 26% that were in good condition in 2012.

The second reference, which is THESL's evidence on these breakers from its previous IRM application, states on page 3, line 22 that there were 66 KSO breakers in 2012. On page 1 of this evidence, it is stated that 21 of these breakers were to be replaced in the 2012 to 2014 period.

a) Given the program to replace 21 of the breakers during 2012-2014, please provide an explanation for the increased percentage of "fair or worse" condition breakers and the decreased percentage of "good" condition breakers;
b) If the explanation is that THESL replaced less breakers than planned, please explain why this is the case, given the importance of these devices.

RESPONSE:

a) The KSO circuit breaker condition data collected in 2014 shows that 40% of the KSO circuit breakers which were in "good" condition in 2012 deteriorated to "fair" condition breakers. In addition, more KSO circuit breakers were tested in 2014 and a majority of the circuit breakers that were tested in 2014 were found to be "fair"

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condition breakers. For these two reasons, the percentage of "fair or worse" condition breakers increased and the percentage of "good" condition breakers decreased. In addition, Toronto Hydro has thus far only completed replacement of nine out of 21 circuit breakers planned replacement in for 2012-2014. This has resulted in 18% more "fair" breakers than would have otherwise been expected had all planned replacements been completed.

b) Despite the importance of the work, Toronto Hydro was only able to complete nine out of the 21 KSO circuit breaker replacements in 2012-2014 due to the timing of the rate decision on the 2012-13 capital program and resource constraints in the work group qualified to complete this type of job.

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INTERROGATORY 39:

Reference(s): **Exhibit 2B, Section E.6 and**
THESL EB-2012-0064, Tab 4, Schedule A, App 1, Tab 1

THESL's DSP has expenditures in the asset categories of System Access, System Renewal, System Service and General Plant. Board staff seeks information that will indicate the degree to which programs authorized in THESL's previous application have been achieved, including the impacts completion of these programs have had on OM&A expenditures, in tabular form including:

a) The objectives which were to be completed in the years 2012 to 2013 (Phase 1) and 2014 (Phase 2, projected) for which capital funding was sought from the Board in EB-2012-0064 according to Reference 2;
b) The total dollars that were sought and approved by the Board, in order to achieve the objective;
c) the capital expenditure (for assets that were actually in-service) that have been spent for the achieved objective;
d) the extent to which the objective was achieved, on a % of dollars basis i.e. "b"/"c";
e) an explanation for the differences where a) the objectives were not achieved or b) where the expenditure, on either a $ per unit or total $expenditure, varied by 10% or more;
f) The OM&A expenditures for the year and how it has been affected by the capital expenditures of earlier years.

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An example of the information Board staff is seeking is provided below for category E6, System Renewal Investments (note that this example only mentions 3 segments of the E6 Assets. All segments for all categories are required):

	Asset	Objective for 2012-2014	Dollars requested	Dollars expended	Achieved	OM&A
E6.1	Underground Circuit Renewal					
	Explanation					
E6.2	PILC Piece-outs and Leakers					
	Explanation					
E6.13	Switchgear Renewal	• Replace 4 obsolete MS switchgear • Replace 4 TS switchgear	Per [Reference 2] Project Schedule B13.1 and 13.2 2012-$19.35m 2013-$18.76m 2014-$20.31m			
	Explanation					
Etc.						

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Please complete the above table and provide similar tables for each of the categories (i.e., System Renewal, System Access, System Service and General Plant) and segments of assets within these categories as shown above.

RESPONSE:

Toronto Hydro has not completed its tracking and analysis of the ICM work program as that program is still being executed. Currently, the following information is available:

- Appendix A provides in-service additions at the segment level for 2012 and 2013 (actuals) and 2014 (forecast). As illustrated in the appendix, Toronto Hydro expects the in-service additions associated with the completed ICM program (excluding Copeland TS) to vary by approximately 5% of the forecasted overall in-service additions.
- Appendix B provides CAPEX at the segment level for 2012 and 2013 (actuals) and 2014 (forecast). Toronto Hydro expects the CAPEX associated with the completed ICM program (excluding Copeland TS) to vary by approximately 5% of the forecasted overall CAPEX.
- Appendix C presents overall CAPEX (actuals) and in-service additions (actuals) for jobs that were listed in approved segments in Phase 1 of the ICM filing (i.e., 2012 and 2013 filed jobs) and that were completed in 2012 or 2013. It compares the sum of the original CAPEX estimates for these jobs versus (i) the sum of the actual CAPEX and (ii) the sum of actual in-service additions associated with the completed jobs. As illustrated, the overall actual spending associated with these jobs has varied by approximately 8% versus overall forecasted spending.

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Toronto Hydro is unable to provide an accurate and complete true-up in advance of 2014 year-end close out and a subsequent analysis and reconciliation of segment level spending in each year. There are a number of practical constraints to providing further detailed true-up data in advance of the completion of the 2014 portion of the ICM work program. These result primarily from changes in job timing and composition within ICM segments, coupled with the need to reconcile large amounts of field data.[1] Moreover, as explained in the response to interrogatory 2A-CCC-23, Toronto Hydro believes that providing early or partial true-up information would be inefficient and inconsistent with the OEB's Decision in EB-2012-0064.

There are generally two different types of segments within Toronto Hydro's ICM work program: those that are asset-based (e.g., switchgear), and those that are geographically-based (e.g., underground). For both of these types of work, as jobs move from high-level planning to detailed design and then to execution, their nature and timing may be adjusted. The following situations represent examples of these types of necessary and prudent adjustments.

- *Job scopes change*
    - A detailed field inspection for a geographically-based job, such as an overhead rebuild, may uncover the need for additional asset refurbishment work to be added to the scope of the job.
- *Jobs are advanced and deferred*
    - A field inspection for a geographically-based job such as an overhead rebuild may identify additional assets that require replacement (e.g., more

[1] Toronto Hydro notes that its proposed Enterprise Resource Planning (ERP) system will make improvements to planning capabilities over the current ERP system. For more on the ERP, please see the ERP Program in the DSP, Exhibit 2B Section 8.6.

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poles and transformers), which necessitates additional design work and delays the start date of construction.

- Feeder loading restrictions imposed due to unusually hot weather may prevent isolation of, or transfer of load to, feeders to allow execution of a job, which necessitates a delay of the job and substitution of another.

- *Jobs are added and deleted from the ICM term*
  - A feeder reconfiguration scheduled during the ICM period may need to be deferred past 2014 because an initially-proposed load transfer was no longer feasible, due to new customer connections resulting in insufficient transfer capacity to undertake the work.
  - A job may need to be added to the ICM program because a new customer could request a connection to the system that would require the expansion and upgrade of an existing transformer. External agencies may require relocation of Toronto Hydro plant to allow for execution of their own work, resulting in the addition of a job to the program and forcing the deferral of another or others.
  - Poor asset performance with a resultant impact on reliability in a given area may require the addition or advancement of a job to the work program, forcing the deferral of another or others.

Toronto Hydro is diligently tracking these changes to the ICM program and intends to provide the OEB and intervenors with a specific reconciliation of forecasts versus actual, including detailed explanations for variance, through the true-up process. However, due to ongoing reconciliation activities and the number of personnel working on the capital program as it moves from planning to detailed design to execution, the detailed information that the utility currently has is in the form of a large amount of field data that

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has not yet been reviewed, compiled, and summarized such that it can be effectively presented. Only once the full ICM program is complete, 2014 financial closeout has occurred and all field data is gathered, will Toronto Hydro be able to begin undertaking the compilation exercise, which it expects to present to the OEB in the second quarter of 2015.

APPENDIX A: Capital Summary Table (ISAs)

		Phase 1: Approved			Phase 2: Approved	Phase 1 + 2: Approved		Phase 1 + 2: Actual/Forecast					Variance	
		In-Service Additions												
		A	B	C	D	E = C + D	F = A + B + E	G	H	I	J	K = G + H + J	L = J - E	M = K - F
Schedule Number	Segments	Total 2012 In-Service Additions	Total 2013 In-Service Additions	Total 2014 In-Service Additions	Total 2014 In-Service Additions	Total 2014 In-Service Additions	Total Approved In-Service Additions (2012-2014)	2012 In-Service Additions Actual (Annual)	2013 In-Service Additions Actual (Annual)	2014 In-Service Additions Actual (YTD June)	2014 In-Service Additions Forecast (Annual)	Total Forecast In-Service Additions (2012-2014)	Total 2014 In-Service Additions Approved vs Forecast	Total 2012-2014 In-Service Additions Approved vs Forecast
B1	Underground Infrastructure	12.74	51.88	23.07	36.70	59.77	124.39	9.35	62.17	10.07	76.54	148.06	16.78	23.67
B2	Paper Insulated Lead Covered Cable Piece Outs and Leakers	0.04	3.34	2.12	1.42	3.54	6.92	0.11	0.15	0.38	6.17	6.44	2.63	(0.48)
B3	Handwell Replacement	6.05	17.73	6.52	7.22	13.74	37.53	5.41	16.61	2.34	10.89	32.92	(2.85)	(4.60)
B4	Overhead Infrastructure	4.02	39.06	21.87	14.78	36.65	79.73	1.03	33.47	12.88	49.82	84.32	13.17	4.59
B5	Box Construction	0.26	14.35	9.02	5.72	14.74	29.34	0.02	5.24	2.90	18.45	23.71	3.71	(5.64)
B6	Rear Lot Construction	7.25	27.02	11.52	5.00	16.52	50.79	3.49	27.23	8.35	16.70	47.42	0.18	(3.37)
B9	Network Vault & Roofs	1.26	13.00	7.34	0.90	8.24	22.50	-	12.33	2.05	2.29	14.62	(5.95)	(7.88)
B10	Fibertop Network Units	0.65	5.52	3.07	2.84	5.85	12.02	0.96	7.06	0.94	5.60	13.62	(0.25)	1.60
[illegible]	Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	-	1.99	1.28	0.10	1.38	3.36	-	1.51	0.29	0.30	1.81	(1.08)	(1.55)
[illegible]	Stations Power Transformers	0.17	2.33	1.36	-	1.36	3.86	-	0.35	0.99	2.90	3.25	1.54	(0.60)
B13.1 & 13.2	Stations Switchgear - Municipal and Transformer Stations	0.77	9.16	5.37	1.41	6.78	16.71	-	-	3.21	3.61	3.61	(3.17)	(13.10)
B20	Metering	2.10	7.75	3.29	3.82	7.11	16.96	-	7.13	3.41	10.82	17.95	3.72	0.99
B21	Externally-Initiated Plant Relocations and Expansions	4.50	20.78	9.72	1.87	11.59	36.87	1.94	7.37	0.03	17.80	27.10	6.21	(9.77)
BXX	ICM Understatement of Capitalized Labour	3.69	4.63	-	-	-	8.32	-	-	-	-	-	-	(8.32)
Total ICM Projects (Excluding Copeland)		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
B17	Copeland Transformer Station	-	-	124.10	-	124.10	124.10	-	2.08	1.30	1.30	3.38	(122.80)	(120.72)
B18.2	Hydro One Capital Contributions	-	-	60.00	-	60.00	60.00	-	-	-	-	-	(60.00)	(60.00)
Total ICM Projects		[redacted]	[illegible]	[redacted]	[redacted]	[redacted]	[illegible]	[illegible]	[illegible]	[illegible]	[redacted]	[redacted]	[illegible]	[illegible]
B7	Polymer SMD-20 Switches	-	0.93	0.60	1.59	2.19	3.12	-	0.84	-	1.51	2.35	(0.68)	(0.77)
B8	SCADA-Mate R1 Switches	-	0.87	0.56	1.89	2.45	3.32	-	1.88	0.03	0.03	1.91	(2.43)	(1.42)
B14	Stations Circuit Breakers	0.34	0.76	0.22	1.05	1.27	2.36	0.22	0.90	0.19	0.50	1.62	(0.77)	(0.74)
B16	Downtown Station Load Transfers	0.30	1.68	0.84	-	0.84	2.82	-	0.03	1.33	1.33	1.36	0.49	(1.46)
B18.1	Hydro One Capital Contributions	-	1.48	-	2.64	2.64	4.12	5.48	2.61	-	1.76	9.85	(0.88)	5.73
C1	Operations Portfolio Capital	29.00	87.75	29.66	49.29	78.95	195.70	39.93	79.39	30.76	99.43	218.76	20.48	23.05
C2	Information Technology Capital	9.25	21.47	6.28	11.25	17.53	48.25	7.56	20.28	6.24	17.49	45.33	(0.04)	(2.92)
C3	Fleet Capital	0.29	0.76	1.75	2.00	3.75	4.80	0.80	0.44	1.83	3.72	4.96	(0.03)	0.16
C4	Buildings and Facilities Capital	3.76	2.90	3.35	5.00	8.35	15.00	1.40	6.16	0.04	7.21	14.77	(1.13)	(0.23)
Total Normal Capital Budget		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

APPENDIX B: Capital Summary Table (CAPEX)

X

Schedule Number	Segments	Phase 1: Approved Capital Spending			Phase 2: Approved Capital Spending	Total Phase 1 + 2 Capex Approved		Phase 1 + Phase 2: Actual/Forecasted Capital Spending					Variance	
		Capex			Capex	Capex	Capex	CapEx						
		A	B	C	D	E = C + D	F = A + B + E	G	H	I	J	K = G + H + J	L = J - E	M = K - F
		2012 Approved Capex	2013 Approved Capex	2014 Approved Capex	Total 2014 Approved Capex	Total 2014 Approved Capex	Total Approved Capex (2012-2014)	2012 Capex (Actual)	2013 Capex (Actual)	2014 Capex Actual (YTD Jun)	2014 Capex IR Fcst as at Jul 2014 (Annual)	Total Fcst Capex (2012-2014)	Total 2014 Capex Approved vs Fcst	Total 2012-2014 Capex Approved vs Fcst
B1	Underground Infrastructure	28.75	58.94	-	77.86	77.86	165.56	36.90	55.97	41.69	107.08	199.95	29.22	34.39
B2	Paper Insulated Lead Covered Cable - Piece Outs and Leakers	0.08	5.42	-	3.55	3.55	9.05	0.14	1.98	2.33	5.96	8.08	2.42	(0.96)
B3	Handwell Replacement	13.65	16.65	-	18.06	18.06	48.36	12.39	11.87	3.96	15.52	39.77	(2.54)	(8.59)
B4	Overhead Infrastructure	9.07	55.88	-	26.01	26.01	90.96	11.59	40.42	28.33	64.12	116.13	38.10	25.16
B5	Box Construction	0.58	23.04	-	14.27	14.27	37.90	0.84	13.84	8.70	23.03	37.71	8.76	(0.18)
B6	Rear Lot Construction	16.36	29.43	-	12.51	12.51	58.29	15.98	29.20	7.35	26.42	65.60	13.91	7.31
B9	Network Vault & Roofs	2.84	18.76	-	2.25	2.25	23.85	2.81	10.59	1.17	1.18	14.58	(1.07)	(9.27)
B10	Fibertop Network Units	1.48	7.71	-	7.09	7.09	16.28	2.14	6.83	1.59	4.66	13.63	(2.43)	(2.65)
B11	Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	-	3.26	-	0.25	0.25	3.51	-	1.59	0.22	0.22	1.81	(0.03)	(1.70)
B12	Stations Power Transformers	0.38	3.48	-	-	-	3.86	0.02	1.54	0.87	2.66	4.21	2.66	0.36
B13.1 & 13.2	Stations Switchgear - Municipal and Transformer Stations	1.73	13.72	-	3.54	3.54	18.98	2.43	5.06	3.21	9.34	16.85	5.81	(2.13)
B20	Metering	4.74	8.40	-	9.54	9.54	22.68	5.69	4.72	4.01	12.56	22.97	3.02	0.29
B21	Externally-Initiated Plant Relocations and Expansions	10.16	24.84	-	4.55	4.55	39.55	9.20	18.57	3.87	6.46	34.23	1.91	(5.33)
BXX	ICM Understatement of Capitalized Labour	8.32	-	-	-	-	8.32	-	-	-	-	-	-	(8.32)
Total ICM Projects (Excluding Copeland)		[illegible]	[illegible]	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
B17	Copeland Transformer Station	8.50	81.00	34.60	-	34.60	124.10	4.07	26.72	10.57	54.51	85.29	19.91	
B18.2	Hydro One Capital Contributions	-	23.00	37.00	-	37.00	60.00	-	18.60	8.85	21.20	39.80	(15.80)	
Total ICM Projects		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[illegible]	[illegible]	[redacted]	[redacted]	[illegible]	[illegible]	[illegible]	
B7	Polymer SMD-20 Switches	-	1.53	-	3.97	3.97	5.50	-	0.84	0.71	1.85	2.69	(2.13)	[illegible]
B8	SCADA-Mate R1 Switches	-	1.43	-	4.73	4.73	6.16	-	1.90	0.45	1.79	3.69	(2.94)	(2.47)
B14	Stations Circuit Breakers	0.76	0.55	-	2.63	2.63	3.94	0.27	1.02	0.09	1.81	3.05	(0.82)	(0.89)
B16	Downtown Station Load Transfers	0.68	2.14	-	-	-	2.82	0.05	2.31	0.42	1.29	3.65	1.29	0.84
B18.1	Hydro One Capital Contributions	1.48	-	-	2.64	2.64	4.12	26.63	20.49	1.04	5.88	53.00	3.24	48.88
C1	Operations Portfolio Capital	64.78	81.63	-	103.78	103.78	250.19	66.67	93.24	41.61	98.24	258.15	(5.53)	7.96
C2	Information Technology Capital	22.00	15.00	-	15.00	15.00	52.00	23.20	17.12	5.99	16.24	56.57	1.24	4.57
C3	Fleet Capital	0.80	2.00	-	2.00	2.00	4.80	0.79	2.16	0.51	2.00	4.95	-	0.15
C4	Buildings and Facilities Capital	5.00	5.00	-	5.00	5.00	15.00	5.13	5.71	1.35	8.25	19.10	3.25	4.10
	Allowance for Funds Used During Construction	1.20	1.40	-	7.95	7.95	10.55	-	-	-	-	-	(7.95)	(10.55)
Total Normal Capital Budget		[illegible]	[illegible]	-	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Toronto Hydro relies on its analysis previously provided to the OEB (attached as Appendix A). Toronto Hydro it has made an adjustment to the calculations to reflect the fact that the initial calculation was based on year-end capital expenditures, rather than in-service amounts. This adjustment has reduced the calculated lost revenue amount. The full calculation, which appeared as Appendix A to the Manager's Summary in EB-2012-0064, is updated and reproduced in Table 4 below.

1 **Table 4: Lost Revenue due to IRM Framework 2012-14**

Lost Revenue due to IRM Framework - 2012-14

($ millions)

In-Service CapEx Approved 2011		348.9		
Funded through Depreciation		-138.8		
Fixed Assets Impact		210.1		
Closing Rate Base in 2011		105.1		
Opening Rate Base in 2012		105.1		
Rate Base	2012	2013	2014	Total
Opening Rate Base	105.1	101.8	98.5	
Depreciation for the year	-3.3	-3.3	-3.3	
Closing Balance	101.8	98.5	95.2	
Average Balance	103.4	100.1	96.8	
Revenue Requirement				
Depreciation	3.3	3.3	3.3	9.8
Cost of capital (6.94%)				
Interest (5.18% x 60%)	3.2	3.1	3.0	9.3
Return on Equity (9.58% x 40%)	4.0	3.8	3.7	11.5
PILs	0.9	0.9	0.8	2.6
Total Revenue Requirement	**11.4**	**11.1**	**10.8**	**33.3**
PILs Calculation				
Target Net Income	4.0	3.8	3.7	11.5
Add: Depreciation	3.3	3.3	3.3	9.8
Less: CCA	-4.7	-4.7	-4.7	-14.1
Income for PILs purposes	2.6	2.4	2.3	7.3
PILs	0.7	0.6	0.6	1.9
Gross-up PILs	0.9	0.9	0.8	2.6
Assumptions				
Depreciation vs CCA ratio	1.43	1.43	1.43	
Average life of Assets	32 years	32 years	32 years	
Tax rate	26.40%	26.40%	26.40%	

Toronto Hydro is proposing to return Gains on Sale proceeds and the Tax Refund in the form of a rate rider to be in place for 36 months beginning May 1, 2015. This refund will serve to smooth bill impacts to customers over the 2015-19 application period.

Toronto Hydro proposes to clear the $33.3M related to lost revenue due to the IRM mechanism through a 48-month rate rider, beginning January 2016. The delay of recovery and the longer-period recovery are intended to reduce and smooth the bill impacts to customers over the 2015-19 period.

Details showing the allocation to rate classes and derivation of the proposed rate riders can be found in Exhibit 9, Tab 3, Schedule 1.

6. TARIFF OF RATES AND CHARGES

Exhibit 8, Tab 3, Schedules 1 through 3, show the 2014 existing, 2015 proposed in mark-up version, and 2015 proposed tariff of rates and charges.

7. REVENUE RECONCILIATION

Exhibit 8, Tab 4, Schedule 1 (OEB Appendix 2-Z) shows the difference between revenue at the proposed rates and allocated revenue requirements by customer class.

8. BILL IMPACTS

Details of the impacts of the proposed rates are provided in Exhibit 8, Tab 7, Schedule 1 (OEB Appendix 2-W). The schedules show the individual and combined impacts of the distribution component, rate riders, other components (e.g., transmission and network charges), and total bill, for a representative level of consumption within each rate class.

8.1. Rate Mitigation

As shown in the Bill Impacts, the impacts on total bill for all classes of the proposed distribution and transmission rates for 2015-19 are less than 10%. As discussed in detail elsewhere in this application (e.g., Exhibit 2B; Exhibit 1B, Tab 2, Schedule 1; Exhibit 4A, Tab 1, Schedule 1), Toronto Hydro has incorporated consideration of rate impacts as part of its proposed capital and OM&A funding requests.

(c) Determination of Revenue Requirements: For the Board's consideration, THESL outlines an alternative to the standard treatment (also filed in evidence for purposes of comparison) of the calculation of the ICM threshold, together with the Board's practice of exempting certain ICM-approved capital expenditures from the application of the half year rule. The alternative approach provides for rate mitigation as it could result in lower cumulative revenue requirements over the three proposed years;

(d) Application of ICM Criteria: Having considered the IRM/ICM Material, THESL describes how its proposed ICM projects satisfy the criteria in THESL's circumstances;

(e) Interim Rates, Implementation of Rates, and True-up upon Rebasing: The schedule to address this Application will not permit 2012 rates to be implemented or effective as of May 1, 2012. Therefore THESL requests that the Board order that existing rates as of May 31, 2012 be declared interim as of June 1, 2012. Implementation of rates would occur at a future date as the Application is decided in due course. Upon rebasing, which is presently foreseen to occur in 2015, THESL understands that a final determination of the revenue requirement flowing from the ICM projects would be made by the Board and allowed revenues would be reconciled to revenues actually received, with any surplus or deficit returned to or recovered from customers. THESL proposes specifically that any revenue deficit arising from an effective date for 2012 rates after May 1, 2012 be included in the reconciliation upon rebasing.

Recognition in Rates of Approved 2011 Year-End Ratebase

THESL's Proposal

THESL proposes that the Board recognize in distribution rates the Board-approved, actual year-end ratebase of 2011, which is materially larger than the average ratebase upon which 2011 rates were set. As a result of the facts that 2011 rates were set on the basis of average ratebase, and that the IRM/PCI adjustment does not by itself recognize material increases in approved ratebase in place by the end of the rebasing year, a material deficiency stemming from the unrecognized ratebase is created in 2012 rates.

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UNDERTAKING NO. J2.17:

Reference(s):

With reference to IR 2A-OEB Staff-30, page 2, part b, to explain why THESL believes the DHC methodology is in compliance with the OEB's decision.

RESPONSE:

Toronto Hydro's belief that the Depreciated Historic Cost ("DHC") methodology is in compliance with the OEB's decision in EB-2009-0180 et al. is based on the following passages from the August 3, 2011 Decision and Order: [1]

> In the February Decision, the Board found that the Applicants' DCF based value was not appropriate for regulatory purposes and confirmed that for regulatory purposes, the Board relies on the depreciated historic cost ("DHC") of assets...
>
> ...
>
> The Board sought to have the Applicants estimate the relationship or proportionality between DHC and DRC as a means to establish a reasonable transfer value rooted in DHC...
>
> Given that historic costs are unavailable, the Board must consider a "next best" solution and concludes that the DRC valuation methodology is a

[1] EB-2009-0180 et al, Decision and Order (August 3, 2011) at pages 14 and 15.

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

> reasonable approach to establish a starting point for the determination of an appropriate transfer value.
>
> The Applicants have provided some descriptive analysis illustrating the comparative effects of a DHC valuation versus a DRC valuation. It is not possible to gain an optimum level of precision as to the expected proportional relationship between the two, but it is not disputed that the DHC analysis of a group of assets will result in a lower value than the DRC valuation. The Board notes that the basis on which the Applicants have made their proposal has the effect of discounting the DRC value by approximately 40%. While the Board dismisses the reasoning provided by the Applicants in support of the proposal, it will accept the value itself. The Board does so in consideration of the particularly unusual circumstances related to the ownership and accounting history of the assets in question.

To summarize, the OEB preferred to value the assets using the DHC methodology. However, because historical costs were not available, the OEB considered that the next best solution was to use the depreciated replacement cost ("DRC") valuation methodology to establish a starting point for the determination of an appropriate transfer price, and to estimate the relationship or proportionality between DHC and DRC to establish a reasonable transfer value rooted in DHC.

For the reasons set out above, Toronto Hydro believes that the DHC methodology complies with the OEB's Decision in EB-2009-0180 et al. The detailed analysis that Toronto has undertaken to update the value of the transferred assets in this proceeding

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

provides a better approximation for the DHC of the transferred assets, and therefore better adheres to the principles of the OEB Decisions.

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J2.18:

Reference(s):

With reference to 1B-BOMA-81, to explain which of the unused variables would have a reasonable likelihood of a statistically significant correlation to cost.

RESPONSE (Provided by PSE):

Without specific details on how the variable would be constructed and the underlying data, PSE is unable to formulate an opinion on the reasonable likelihood of each variable being statistically significant.

Table 4: Revenue Requirement from Streetlighting Assets ($ millions) /C

Revenue Requirement Component	2015 Test Year	
NBV of Assets - opening	39.8	
NBV of Assets - closing	39.1	
Average NBV	39.5	
Working Capital Allowance	0.2	
Streetlighting Ratebase	**39.7**	
OM&A	3.7	
Cost of Capital	2.5	
Depreciation	1.6	
PILS	0.3	/C
Service Revenue Requirement	**8.1**	/C
Revenue Offset - Contract Revenue	8.1	/C
Base Revenue Requirement	**0.0**	

5.1. Revenue Offset

Under existing agreements between TH Energy and the City of Toronto, TH Energy receives service fees for the maintenance and operation of the street lighting assets. Given the transfer of a portion of these assets into Toronto Hydro's rate base as distribution assets, Toronto Hydro proposes to allocate a portion of the revenue that it expects to receive to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

5.2. Cost Allocation

For the purposes of Cost Allocation, Toronto Hydro has allocated all of the costs associated with the transfer of the street lighting assets to a combination of the Street lighting rate class and the Unmetered Scattered Load ("USL") rate class. No other rate

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 31:

Reference(s): Exhibit 2A, Tab 5, Schedule 1, p. 22

Table 4 of the above reference "Revenue Requirement from Streetlighting Assets ($ millions)" shows a service revenue requirement for the 2015 Test year of $8.1 million, which is offset by a "Revenue Offset – Contract Revenue" amount of $8.1 million producing a base revenue requirement of zero.

THESL's explanation of this adjustment is that:

> Under existing agreements between TH Energy and the City of Toronto, TH Energy receives service fees for the maintenance and operation of the street lighting assets. Given the transfer of a portion of these assets into Toronto Hydro's rate base as distribution assets, Toronto Hydro proposes to allocate a portion of the revenue that it expects to receive to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

a) Please state whether the existing agreements between TH Energy and the City of Toronto will be transferred over to THESL and, if so, whether they will be transferred unchanged, or if any modifications will be made. If modifications are anticipated, please state what they will be;
b) THESL states that it proposes to allocate a portion of the revenue it expects to receive. Please state what the anticipated total amount of expected revenue would be;

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) If THESL was not to make the revenue offset shown in Table 7, please state what the impact would be.

RESPONSE:

a) The existing agreements between TH Energy and the City of Toronto will not be transferred to Toronto Hydro. Rather, to meet its obligations under the existing agreements, insofar as they relate to the transferred portion of the assets, TH Energy has sub-contracted the performance of the services to Toronto Hydro.

b) The total amount of revenue that Toronto Hydro expects to receive from the City Contract is $8.1 million, consistent with the revenue requirement calculation outlined in Exhibit 2A, Tab 5, Schedule 1, Table 7. For greater clarity, the $8.1 million figure represents a portion of the total revenue under TH Energy's contract with the City of Toronto. Toronto Hydro proposes to allocate this entire $8.1 million amount to offset the revenue requirement costs associated with the transferred assets.

c) If Toronto Hydro did not include $8.1M from the Streetlighting contract as a directly allocated revenue offset, then $8.1M of additional Base Revenue requirement would need to be collected through Base Distribution Rates charged to all customers.

Table 3: Long-Term Debt

Description	Maturity	Outstanding Principal	Rate
$245M Prom Note	Nov. 14, 2017	245,057,739	5.20%
$245M Prom Note	Nov. 12, 2019	245,057,739	4.54%
$300M Prom Note	Nov. 19, 2021	300,000,000	3.59%
$15M Prom Note	Jan. 1, 2022	$15,000,000	3.32%
$250M Prom Note	Apr. 10, 2023	250,000,000	2.96%
$200M Prom Note	May 21, 2040	200,000,000	5.59%
$200M Prom Note	Apr. 9, 2063	200,000,000	4.01%
$45M Prom Note	Due on demand	45,000,000	6.16%
Total		**1,500,115,478**	**4.30%**

Forecasted new debt issuance for 2014-15 is driven primarily by Toronto Hydro's capital plans and by the repayment requirements of the maturing debt. Details of the forecast debt issues for 2014-15 are shown in Table 4.

Table 4: Forecasted Long-Term Debt Issues

Description	Issue Date	Term	Principal	Underlying Govt Bond Rate (%)	Corporate Spread Forecast (%)	Forecast Coupon Rate (%)
$200M Prom Note (Series 10)	Aug. 31, 2014	30 Years	$200,000,000	3.29	1.45	**4.74**
$300M Prom Note (Series 11)	Jun. 30, 2015	10 Years	$300,000,000	3.02	1.15	**4.17**

Forecasted debt rates are based on the Ten-Year Government of Canada Bond Yield Forecast (using Bloomberg L.P.) and the current spread of 30-Year over Ten-Year Government of Canada Bond Yield, when applicable, plus Toronto Hydro's estimate of corporate spreads at the time of issuance (inclusive of the five basis point administration fee).

OEB Appendix 2-OB
Debt Instruments

This table must be completed for all required historical years, the bridge year and the test year.

Year 2011

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) (Note 2)	Interest ($) (Note 1)	Additional Comments, if any
1	2003 Series 1	THC	Affiliated	Fixed Rate	6-May-03	10	$ 180,000,000	6.16%	$ 11,088,000	
2	City Note (Part 3)	THC	Affiliated	Fixed Rate	7-May-03	8.7	$ 245,057,739	6.16%	$ 15,054,199	
3	City Note (Part 4)	THC	Affiliated	Fixed Rate	7-May-03	10	$ 245,057,739	6.16%	$ 15,095,557	
4	2007 Series 2	THC	Affiliated	Fixed Rate	14-Nov-07	10	$ 245,057,739	5.20%	$ 12,743,002	
5	2009 Series 3	THC	Affiliated	Fixed Rate	12-Nov-09	10	$ 245,057,739	4.54%	$ 11,125,621	
6	2010 Series 6	THC	Affiliated	Fixed Rate	20-May-10	30	$ 200,000,000	5.60%	$ 11,200,000	
7	2011 Series 7	THC	Affiliated	Fixed Rate	18-Nov-11	10	$ 300,000,000	3.59%	$ 1,298,301	
8										
9										
10										
11										
12										
Total							$ 1,395,723,948	5.56%	$ 77,604,681	

Notes

1 If financing is in place only part of the year, calculate the pro-rated interest and input in the cell.

2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009

3 Add more lines above row 12 if necessary.

[all tabular amounts in thousands of Canadian dollars]

12. NOTES PAYABLE TO RELATED PARTIES

Notes payable to related parties consist of the following:

	2013 $	2012 $
Notes payable to related parties:		
6.16% Long-term note payable to the Corporation due May 6, 2013	—	180,000
5.20% Long-term note payable to the Corporation due November 14, 2017	**245,058**	245,058
4.54% Long-term note payable to the Corporation due November 12, 2019	**245,058**	245,058
5.59% Long-term note payable to the Corporation due May 21, 2040	**200,000**	200,000
3.59% Long-term note payable to the Corporation due November 18, 2021	**300,000**	300,000
2.96% Long-term note payable to the Corporation due April 10, 2023	**250,000**	—
4.01% Long-term note payable to the Corporation due April 9, 2063	**200,000**	—
6.16% Long-term note payable to the Corporation due May 6, 2013	—	245,058
6.16% Demand note payable to the Corporation due on demand	**45,000**	45,000
3.32% Demand note payable to the Corporation due on the earlier of demand and January 1, 2022	**15,000**	15,000
3.09% Demand note payable to TH Energy due on the earlier of demand and July 1, 2022	—	14,013
Total notes payable to related parties	**1,500,116**	1,489,187
Less: Unamortized discount/premium	**6,917**	4,938
Less: Current portion of notes payable to related parties	**60,000**	498,906
Long-term portion of notes payable to related parties	**1,433,199**	985,343

All notes payable to related parties of LDC rank equally.

On April 9, 2013, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $250,000,000, which bears interest at a rate of 2.96% per annum payable on April 10, 2023. Interest is calculated and payable semi-annually in arrears on October 10 and April 10 of each year.

On April 9, 2013, LDC issued a promissory note to the Corporation. The principal amount of the promissory note is $200,000,000, which bears interest at a rate of 4.01% per annum payable on April 9, 2063. Interest is calculated and payable semi-annually in arrears on October 9 and April 9 of each year.

The net proceeds of the promissory notes were mainly used to repay LDC's notes payable to the Corporation which matured on May 6, 2013.

13. EMPLOYEE FUTURE BENEFITS

Pension

LDC's full-time employees participate in a pension plan through OMERS. The plan assets are pooled together to provide benefits to plan participants and are not segregated in separate accounts for each member entity. As at December 31, 2013, the OMERS plan was 88% funded, with a funding deficit of approximately $8,600,000,000. For the year ended December 31, 2013, the total contributions of all participating employers and employees were approximately $3,500,000,000. For the year ended December 31, 2013, LDC's contributions were $18,102,000 [2012 - $16,374,000], representing less than five percent of total contributions to the plan.

For 2013, OMERS contribution rates were 9.0% up to the year's maximum pensionable earnings ["YMPE"] and 14.6% over YMPE for normal retirement age of 65 [2012 – 8.3% up to YMPE and 12.8% over YMPE for normal retirement age of 65].

[all tabular amounts in thousands of Canadian dollars]

As at December 31, 2012, OMERS had approximately 266,000 active members. As at December 31, 2013, approximately 1,500 members [December 31, 2012 – 1,700] had a current relationship with LDC.

Post-retirement benefits other than pension

a) Benefit Obligations

	2013 $	2012 $
Balance, beginning of year	**253,890**	244,326
Service cost	**4,816**	5,035
Interest cost	**10,570**	11,454
Benefits paid	**(10,432)**	(8,069)
Actuarial (gain) loss	**(20,230)**	254
Transfer from related parties	**178**	890
Balance, end of year	**238,792**	253,890

On February 13, 2014, LDC's unionized workforce ratified a collective agreement to expire at the end of January 2018. The agreement does not contain terms that create a post-retirement benefits liability in respect of past service.

b) Amounts recognized in regulatory assets

	2013 $	2012 $
Actuarial loss	**38,767**	61,477
Prior service cost	**14**	22
Total recognized in regulatory assets *[note 9]*	**38,781**	61,499

As at December 31, 2013, the estimated actuarial loss and prior service cost that are expected to be amortized from regulatory asset to net periodic benefit cost in 2014 are $909,000 and $nil, respectively.

c) Components of net periodic benefit costs

	2013 $	2012 $
Service cost	**4,816**	5,035
Interest cost	**10,570**	11,454
Amortization of actuarial loss	**2,064**	3,146
Amortization of prior service cost	**2**	840
Net periodic benefit cost	**17,452**	20,475
Capitalized as part of PP&E	**6,623**	7,305
Charged to operations	**10,829**	13,170

[all tabular amounts in thousands of Canadian dollars]

d) Expected benefit payments

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid over the next five years, and in the aggregate for the five fiscal years thereafter:

	Post-retirement Benefits $
2014	**8,191**
2015	**8,403**
2016	**9,090**
2017	**9,541**
2018	**10,112**
2019-2023	**59,394**

e) Significant assumptions

	2013 %	2012 %
Accrued benefit obligation as at December 31:		
Discount rate	**4.75**	4.25
Benefit costs for years ended December 31:		
Discount rate	**4.25**	4.75
Assumed health care cost trend rates as at December 31:		
Rate of increase in dental costs assumed for next year	**4.00**	4.00
Rate of increase in medical costs assumed for next year		
For pre July 2000 retirements	**6.00**	6.50
For other retirements	**7.50**	8.00
Rate that medical cost trend rate gradually declines to		
For pre July 2000 retirements	**5.00**	5.00
For other retirements	**5.00**	5.00
Year that the medical cost trend rate reaches the ultimate trend rate		
For pre July 2000 retirements	**2016**	2016
For other retirements	**2019**	2019

f) Sensitivity analysis

Assumed medical and dental care cost trend rates have a significant effect on the amounts reported for medical and dental care plans. A one-percentage-point change in assumed medical and dental care cost trend rates would have the following effects for 2013:

	Increase $	Decrease $
Total of current service and interest cost (at 4.25%)	**2,327**	**(2,046)**
Accrued benefit obligation as at December 31, 2013 (at 4.75%)	**30,388**	**(26,664)**

[all tabular amounts in thousands of Canadian dollars]

Assumed interest rates have a significant effect on the amounts reported for the total accrued benefit obligation and expense. A one-percentage-point change in assumed interest rates would have the following effects:

	Increase $	Decrease $
Accrued benefit obligation as at December 31, 2013	**(37,041)**	**45,469**
Estimated net periodic benefit cost for 2014	**(1,713)**	**2,937**

14. ASSET RETIREMENT OBLIGATIONS

The reconciliation between the opening and closing ARO liability balances is as follows:

	2013 $	2012 $
Balance, beginning of year	**5,004**	4,831
ARO liabilities settled in the year	**(573)**	(313)
Accretion expense	**177**	170
Revision in estimated cash flows	**1,639**	316
Balance, end of year	**6,247**	5,004

15. FINANCIAL INSTRUMENTS

a) Recognition and measurement

As at December 31, 2013 and December 31, 2012, the fair values of cash and cash equivalents, net accounts receivable, unbilled revenue, advance from related party, and accounts payable and accrued liabilities approximate their carrying values due to the short maturity of these instruments *[note 4[i]]*. The fair values of customers' advance deposits approximate their carrying values taking into account interest accrued on the outstanding balance. Obligations under capital lease are measured based on a discounted cash flow analysis and approximate the carrying value as management believes that the fixed interest rates are representative of current market rates.

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

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2015 to December 31, 2019.

The Applicant, Toronto Hydro-Electric System Limited (referred to in this application as the "Applicant, "Toronto Hydro", "THESL", the "Company" or the "Utility"), is a corporation incorporated under the *Business Corporations Act*, (Ontario), and is licensed by the Ontario Energy Board (the "OEB") under licence number ED-2002-0497 to distribute electricity in the City of Toronto.

Toronto Hydro hereby applies to the OEB pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") as amended, for approval of its proposed

1) electricity distribution rates and other charges effective May 1, 2015; and
2) custom Price Cap Index ("Custom PCI") framework to set distribution rates effective for the period January 1, 2016 to December 31, 2019, and the rates and charges resulting from it.

This application is prepared in accordance with the following OEB documents:

1) Filing Requirements for Electricity Distribution Rate Applications issued by the OEB on November 14, 2006 under file number EB-2006-0170, and updated on July 17, 2013 (the "Filing Requirements"); and

3.3. Custom Capital Factor

The premise of the inclusion of a custom capital factor ("CCF" or "C-factor") is to reconcile the OEB's guidance that the CIR framework is best suited for utilities with significant, multi-year capital investment requirements as it is clear that the standard 4th Generation IR framework is not.

The proposed C-factor is designed as a rate adjustment mechanism that is directly proportional to the degree of capital investment required by Toronto Hydro, as detailed in its DSP (Exhibit 2B). It is comprised of two sub-components that serve two primary functions:

- Reconcile Toronto Hydro's capital investment need in a price cap framework; and,
- Return to ratepayers the funding already provided for capital through the standard "I – X" increase.

The first sub-component, termed "C_n", is determined as the percent change in total revenue requirement that is attributable to changes in capital-related revenue requirement – that is, depreciation, return on equity, interest and PILs/taxes. Changes in capital-related revenue requirement are based on forecast changes in average annual rate base, associated depreciation and taxes. Tax rates and the cost of capital are maintained at their 2015 levels, consistent with the standard 4th Generation IR treatment.

For Toronto Hydro, C_n in 2016 would be determined on the following basis:

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 61:

Reference(s): Exhibit 3, Tab 1, Schedule 1, pp. 9-10

Table 3 at page 9 of the above reference shows regression variables by rate class. While other classes with the exception of those for Street lighting and Unmetered Load show multiple regression variables, the Competitive Sector Multi-unit Residential class shows only one which is normalized average use per customer.

Page 10 of the above reference explains the use of normalized average use per customer as follows:

> The load forecast for Competitive Sector Multi-unit Residential ("CSMUR") was determined using the NAC as the most suitable model for this relatively new rate class. Historically, CSMUR customers were part of Residential rate class, however, as directed by the Ontario Energy Board in EB-2010-0142, Toronto Hydro established a separate rate class with rates implemented as of June 1, 2013.

a) Please state why NAC was determined as the most suitable model for the CSMUR class;
b) Please state whether there have been any changes to the regression variables for the other rate classes relative to those presented in the EB-2010-0142 application and, if so, why such changes were made.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

RESPONSE:

a) The CSMUR class is a new class with consumption data being collected as of its implementation date – June 1, 2013. With the limited historical load data available, Toronto Hydro determined that using the normalized average use per customer would be the most suitable forecast approach for this class. As more historical data for the CSMUR class becomes available, Toronto Hydro anticipates also developing multivariate models for this class.

b) Toronto Hydro confirms that there have been changes to the regression variables used for the other rate classes relative to the last rebasing application (EB-2010-0142), specifically for the GS < 50 kW, GS 50-999 kW, GS 1,000-4,999 kW and Large Use rate classes. The table below lists the regression models used in this application (EB-2014-0116) and the 2011 rebasing application (EB-2010-0142).

Toronto Hydro assesses the appropriateness of all model variables each time it goes through its forecasting exercises. The regression variables are tested for their statistical significance, along with other explanatory variables in the regression models for each customer class independently. Based on the results of the statistical estimation (variables significance in the models and (adjusted) R Squared) "the best-fitted" variables are chosen for those customer classes. As a result, some of the variables become more statistically significant, while the others less.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

1 **Regression Variables by Rate Class (2015 CIR and 2011 COS)**

GS<50 kW		GS 50-999 kW		GS 1,000-4,999 kW		Large Use	
2015 CIR EB2014-0116	2011 COS EB-2010-0142	2015 CIR EB2014-0116	2011 COS EB-2010-0142	2015 CIR EB2014-0116	2011 COS EB-2010-0142	2015 CIR EB2014-0116	2011 COS EB-2010-0142
Toronto Unemploy ment Rate	**Toronto City Population**	**Toronto Unemploy ment Rate**	HDD10 per day	**Toronto Unemploy ment Rate**	**Linear Trend (January 2007)**	**Number of LU customers**	**Linear Trend (January 2007)**
Dew Point Temp.	**Business Days Percent.**	HDD10 per day	CDD per day	HDD10 per day	HDD10 per day	**Time Trend**	HDD10 per day
Time Trend	Linear Trend (July 2002)	CDD per day	Dew Point Temp.	CDD per day	CDD per day	HDD10 per day	CDD per day
HDD10 per day	HDD10 per day	Dew Point Temp.	Business Days Percent.	Dew Point Temp.	Dew Point Temp.	CDD per day	Dew Point Temp.
CDD per day	CDD per day	Business Days Percentage	Number of GS 50-1000 kW customers	Business Days Percent.	Business Days Percent.	Dew Point Temp	Business Days Percent.
Number of GS<50 kW customers	Number of GS<50 kW customers	Number of GS 50-1000 kW customers	Blackout dummy	Number of GS 1,000-4,999 kW customers	Number of GS 1,000-4,999 kW customers	Business Days Percent.	Blackout dummy
Blackout dummy	Blackout dummy	Blackout dummy	Intercept term	Blackout dummy	Blackout dummy	Blackout dummy	Intercept term
Intercept term	Intercept term	Intercept term		Intercept term	Intercept term	Intercept term	

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 62:

Reference(s): Exhibit 3, Tab 2, Schedule 1, p. 6

The above reference discusses gains from sale of utility properties in the context of revenue offsets. In its discussion, THESL notes that gains on the sales of such properties were recorded as revenue offsets in the 2011 to 2014 period.

THESL, however, states that in 2015 it expects to sell idle properties at 5800 Yonge and 28 Underwriters and given the relatively large value of these properties, these gains are not recorded as part of revenue offsets, but are proposed to be treated as regulatory liabilities to be refunded to customers over a multi-year period.

a) Please state whether THESL would have any reasons other than the potential size of these gains for its proposed treatment and, if so, what they would be. If not, please explain why THESL believes the size of the gain should be a criteria in determining its treatment and what criteria the Board should use in determining whether a gain should be treated as a revenue offset, or a regulatory liability;
b) In the event the Board was to determine that the 2015 gains were to be treated as revenue offsets, please describe any concerns THESL would have with such treatment.

RESPONSE:

a) As noted in Exhibit 8, Tab 1, Schedule 1, page 17, Toronto Hydro has proposed clearance of the 2015 Gains on Sale (as well as the proposed Tax Refund) through a

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

rate rider in place for 36 months, to assist in smoothing bill impacts for customers. Providing for full clearance through a single 2015 Revenue Offset for this sizable amount is problematic under THESL's proposed 2015-19 framework since it would effectively set into base rates an equivalent full amount in each year (which would be inappropriate since the offset only occurs once). It would also eliminate the desired bill impact smoothing.

b) As noted above, if the Board were to determine that the gains were to be treated as a revenue offset, Toronto Hydro would be concerned that a custom clearance term could not be accommodated under its proposed custom PCI formula, and as a result, the gains could only be cleared over the full five-year rate term (by including one-fifth of the total amount as a revenue offset in 2015). This would nullify the positive impacts a three-year clearance would have on rate smoothing.

they occur. Thus, SAIDI performance tends to be more related to OM&A spending, whereas SAIFI performance is related more to capital spending.

1.6 Custom IR Conclusions

PSE's benchmark research leads us to the following statements relating to the company's Custom IR proposal:

1. Toronto Hydro is entering the Custom IR period with strong recent cost performance (i.e., costs are below the expected values), with its average 2010 to 2012 total costs being estimated at 21.5% below benchmark values using the combined dataset results.[10]

2. This strong cost performance persists to 2015, although with some moderation. Toronto Hydro's 2015 total cost level forecast is estimated to be 7.1% below benchmark values, and is, in our opinion, reasonable from a benchmarking perspective.

3. Toronto Hydro's Custom IR period (2015 through 2019) total cost level projections remain below benchmark expectations. By 2019, the company is estimated to still be below benchmark values by 2.6%. Based on this, the company's Custom IR projections are, in our opinion, reasonable from a benchmarking perspective.

4. Total costs are projected to be well within the 0.3% stretch factor range of plus/minus 10% set in the November 2013 Board Report. In terms of ranking, in the combined total cost rankings based on historical performance, Toronto Hydro is 30th out of the 156 Ontario/U.S. utilities. If Ontario distributors are isolated in the rankings, for the combined model, Toronto Hydro is ranked 15th out of the 71 distributors. Based on these findings, reducing the stretch factor from 0.6% to 0.3% seems in line with the Board's intention of assigning a 0.3% stretch factor to utilities with "normal" total cost benchmark evaluations.

5. Toronto Hydro's capital infrastructure seems to be producing a higher than expected number of outages. The company's average 2010-2012 SAIFI is 73% above benchmark expectations. This implies Toronto Hydro customers experience 73% more outages then our models predict. The SAIFI projections, assuming full funding, move the company towards the benchmark SAIFI value, reducing the number of outages experienced by customers. Thus, the company's plan to increase capital spending to address SAIFI is, in our opinion, reasonable from a benchmarking perspective.

6. Toronto Hydro's response to outages, measured by SAIDI, is quite strong and is projected to continue to be strong. The company's 2010-2012 average is 48% below benchmark expectations. This implies that Toronto Hydro customers experience 48%

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[10] In this section, we discuss only the results for the combined dataset. The U.S.-only results are similar, although they indicate Toronto Hydro is even further below its benchmark values than when using the combined dataset (i.e. when using the U.S.-only dataset, Toronto Hydro's benchmarked costs are higher, thus its performance more impressive).

Table 2 PSE Reply Report Cost Model Results

Year	Percent of U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Total Cost THESL, $M
2002	-28.0%	$591	$446
2003	-26.5%	$602	$462
2004	-25.4%	$600	$466
2005	-32.4%	$638	$461
2006	-29.2%	$641	$479
2007	-29.2%	$676	$505
2008	-26.0%	$687	$529
2009	-22.6%	$713	$569
2010	-17.8%	$739	$619
2011	-14.0%	$756	$657
2012	-13.9%	$739	$643
2013	-6.3%	$755	$708
2014	-4.6%	$816	$780
2015	4.1%	$843	$878
2016	5.2%	$895	$942
2017	6.2%	$943	$1,003
2018	6.3%	$993	$1,057
2019	7.0%	$1,046	$1,121

Demand-side management (DSM) is a distribution activity regulated at the local jurisdictional level, not at the Federal level. Each jurisdiction sets its own methods for the accounting for and recovery of DSM activities, including direct expensing or recovery through of some or all of the costs in a regulatory asset. They may also have specific reporting requirements for DSM activities. Look to each company's tariff, and the local jurisdictional authority, for specific information on the treatment of DSM activities, and in which regulatory accounts such activity is charged.[6]

In an effort to provide conservative evidence in this proceeding and only address clear-cut necessary changes, PSE will assume that U.S. utilities report all CDM activities in the customer service and information expense category (even though this is likely not the case for all U.S. utilities). Thus, PSE included all of THESL's CDM expenses, which are projected at $51 million in 2015. Along with the smart meter expense inclusions for THESL, this assumption also makes the PSE Reply Report less favorable to THESL (e.g., if we were able to ascertain all CDM expenses for each utility and how they were recorded, THESL's results would most likely be better).

3.3 Adjustment #3: Model Specification with Urban Core and High Voltage Variables

PEG modified PSE's U.S. model by removing the urban core variable and including a high voltage capacity variable.[7] In this PSE Reply Report, following established industry practice, PSE removed PEG's high voltage variable, which is statistically insignificant and incorrectly signed, and re-included PSE's urban core variable, which is logical, signed correctly and statistically significant at a 99% confidence level.

The fact that the high voltage variable is signed incorrectly (it should be positive, but is negative in the PEG Report Corrections) and statistically insignificant at even the 90% confidence level disqualifies the variable from being included. Business condition variables that are incorrectly signed or statistically insignificant are not included in econometric benchmarking models. PEG's use of this variable, and its exclusion of the urban core variable, are not in-line with benchmarking best practices. PEG has stated the need for business condition variables to be correctly signed and statistically significant in a report to the Board. In a report dated March 20, 2008 "Benchmarking the Costs of Ontario Power Distributors" on page 52, PEG writes:

> All included business conditions were required to have elasticity estimates that were plausible (e.g. sensibly signed) and significantly different from zero. All variables found to be statistically significant were included in the final model. Since, additionally, we consider for inclusion only variables that are predicted by theory or that seem relevant on the basis of our industry experience, the model is not a 'black box' that confounds attempts at earnest appraisal.

In this proceeding, PEG has provided conflicting models with different signs for the high voltage variable, but in both models the variable is statistically insignificant. PEG's original December 2014 Report provided a model in Table Three that showed a statistically insignificant high voltage variable, but one that was positively signed. Then in PEG Report Corrections, PEG submitted a revised Table Three; this time the high voltage variable was negatively signed, but still statistically

[6] Correspondence from FERC.

[7] PEG also removed the percent undergrounding variable, although failed to mention this change or explain why the change occurred in the PEG Report.

insignificant. Neither model meets the benchmarking best practice principles previously stated by PEG.[8]

The Appendix of PSE's September Report provided an engineering analysis showing that utilities will have different cost challenges based on the development characteristics of their service territories. Costs are found to be well over double for urban service territories, relative to suburban ones. Excluding the urban variable creates an omitted variable bias in PEG's model and unfairly disadvantages THESL in the process.

Excluding the urban core variable also violates benchmarking best practice. PEG wrote in a 2010 report written on behalf of Public Service Company of Colorado:

> One important result is that an econometric cost model can yield *biased* predictions of the true benchmark if relevant business condition variables are excluded from the model. It is therefore desirable to include in an econometric benchmarking model all business conditions which are believed to be relevant, for which good data are available at reasonable cost, and which have plausible and statistically significant parameter estimates.[9]

The PSE urban core variable is necessary to include and meets PEG's stated requirements for inclusion. PEG's high voltage variable does not meet those same requirements. Substituting the high voltage variable for the urban core variable is, therefore, a necessary change to the total cost model and one that is made in this PSE Reply Report.

PEG summarizes this issue by writing the following on page 3 and 4 of the PEG Report:

> The third stage of PEG's review examined PSE's business condition variables. PEG made two necessary changes to PSE's selected business conditions. The first was adding a variable to reflect MVa of transformer capacity for stations with primary voltage levels at or above 50 kV. This variable is necessary to control for US utilities' costs of owning high voltage assets. The second was eliminating the urban core dummy variable from PSE's model because it is redundant, inappropriate in electricity distribution benchmarking, and appears to distort the estimated impact of other business condition variables (especially undergrounding).

PEG seems to have added new requirements for including business condition variables. PEG claims that the urban variable is "redundant, inappropriate in electricity distribution benchmarking, and appears to distort the estimated impact of other business condition variables (especially undergrounding)". PSE addresses each of these concerns in turn below.

3.3.1 The Urban Core Variable Is Not Redundant

On page 29 of the PEG Report, PEG states: "Since PSE's model already includes a percent of plant underground variable, including an 'urban core dummy' would be redundant at best." PEG appears

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[8] PSE also notes that the high-voltage expenses are included in the "TFP-based" cost measure used by PSE. PEG incorrectly criticizes PSE's use of a TFP-based cost in its Responses to Interrogatories (1-THESL-61) and in the PEG Report. The TFP-based costs capture the high-voltage costs that PEG is describing in its response. The TFP-based cost definition also excludes contributions in aid of construction (CIAC), which PEG itself subtracts from their cost definition for THESL (see PEG's response to 1-THESL-20). Besides adding smart meter expenses, the rationale for which PEG fails to empirically substantiate in its response to 1-THESL-19 , PEG is effectively advocating for the cost definition used by PSE, while at the same time criticizing PSE for its use.

[9] PEG Report of Dr. Mark Newton Lowry, President of PEG, filed on Behalf of Public Service Company of Colorado on December 17, 2010. Report title, "Statistical Analysis of Public Service of Colorado's Forward Test Year Proosal".

to be saying that the percent underground variable should be sufficient to pick up the impacts of higher costs for urban areas. This is incorrect for several reasons.

1. In our experience with hundreds of distributors, undergrounding tends to cost a great deal more in urban centers than in rural or suburban settings. In more rural and suburban settings, direct bury cables with pad mounted equipment are typically used. These are much less expensive than concrete-encased duct bank installations with underground vaults, submersible equipment and massive civil infrastructure, which are found in urban settings.
2. Similarly, overhead line construction can be found within all service area environments, but will also cost a great deal more in urban settings; these costs are not captured by an undergrounding variable.
3. The underground variable is not found in PEG's final model or in PSE's Reply model. PEG states in 1-THESL-32 the undergrounding variable was excluded because it was either statistically insignificant or had the wrong sign. It is not sensible to exclude the urban variable on the basis it is "redundant," but then also exclude the variable PEG claims serves as its replacement.

The costs of all types of construction based on the developed areas are laid out in the Appendix to the PSE September Report. PEG's statement that the percent underground variable will pick up the cost variations for an urban utility is not correct. In the end, serving an urban core simply increases costs, and our report shows that the urban core variable captures this fact.

3.3.2 The Urban Core Variable Is Not Inappropriate

We now move to PEG's claim that the urban core variable is "inappropriate in electricity distribution benchmarking." This statement is contrasted with PEG's own use of an urban core variable in prior gas distribution cost benchmarking studies. On page 28 of the PEG Report it lays out its rationale for this statement as follows:

> Some PEG studies have used this variable in gas distribution models, but the rationale for using such a dummy variable is much stronger for gas distribution because essentially all gas distribution assets are underground. A dummy variable is one means of distinguishing between the higher costs of installing and maintaining underground gas distribution assets in densely-populated, mature urban areas compared with "greenfield" suburban territories.

The reasons that costs increase for urban gas distributors are the exact same reasons costs increase for urban electric distributors. Constructing and maintaining either underground or overhead assets in a densely-populated and mature urban area will cost considerably more than constructing and maintaining either overhead or underground power lines in a suburban environment. This is the same message in the PSE September Report Appendix.

3.3.3 The Urban Core Does Not Distort the Impact of Other Variables

PEG's last criticism of the urban core variable is that it "appears to distort the estimated impact of the other business condition variables (especially undergrounding)." Recall that PEG has already eliminated the undergrounding variable from their model. Eliminating the undergrounding variable vitiates the distortion argument (similar to PEG's redundancy concerns). Furthermore, using econometrics, <u>any</u> included variable will change the estimated impacts of the other business condition variables. This is why there needs to be a theoretical basis for including variables, and they must be correctly signed and statistically significant. To not include a variable that is predicted by theory, correctly signed, and statistically significant because it will change the other business condition variables would distort the model by creating what is known in econometrics

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as an "omitted variable bias." By excluding the urban core variable, PEG's model suffers from this bias.[10]

The system R-squared statistics of PEG's model and PSE's Reply Report model can be compared. R-squared statistics are measures of "goodness of fit" and basically present how much of the variation in the dependent variable (total cost) is explained by the model. PEG's R-squared is 0.926, implying that 92.6% of the variation in the data set is explained in their model. After making the three adjustments to PEG's model, the R-squared of the resulting model increases to 0.962. This supports PSE's position on the need to include variables that are logical, statistically significant, and properly signed.

In summary, standard industry practice results in including the urban core variable and excluding PEG's high voltage variable. This will also capture a highly relevant cost driver (serving an urban core), which is necessary to provide a fair and accurate model to evaluate THESL's cost performance.

3.4 PSE Reply Total Cost Model after Adjustments

The model estimates are provided in Table 1. All first order and business condition variables are logical, correctly signed, and statistically significant at a 95% level of confidence.

The PSE Reply Report total cost results are provided in Figure 3 and Table 2. THESL's costs are under the PSE Reply Report total cost benchmarks until 2015, when the company's cost is projected to move higher than its benchmarks by around four percent. THESL's projected costs assume that the company's proposed Custom IR plan is approved in full. Table 2 shows the numerical PSE Reply Report model results. THESL Custom IR projections remain within the 4th Generation IR 0.3% stretch factor range of +\- 10%.

[10] Please see PEG's statement on the prior page regarding what causes bias and how it can be prevented by including all business conditions that are plausibly signed, can have data gathered, and are statistically significant.

1-THESL-33.

a) Does the final PEG model (Table Three) control for the cost impacts of undergrounding? If yes, please explain.

The "final" benchmarking model presented in the PEG Report did not identify an independent, statistically significant impact of undergrounding on electricity distribution cost. This is consistent with the PEG benchmarking model the Board is currently using to assign stretch factors for Ontario electricity distributors. This PEG model also did not identify a statistically significant impact of undergrounding on Ontario distributors' total costs, although PEG econometric models developed earlier in the 4th Gen IR proceeding did find greater undergrounding was associated with higher electricity distribution costs in Ontario. This finding was no longer true after the final, more carefully defined cost measures for Ontario distributors were developed in consultation with industry and stakeholders during the course of the 4th Gen IR proceeding.

In PEG's opinion, the lack of an undergrounding variable in "the final PEG model" represents a substantial improvement on the "US only" benchmarking model presented in the PSE Report. PSE's US only benchmarking model found that greater undergrounding of assets *reduced* electricity distribution costs for THESL and the US electric utility sample. PEG believes PSE's result is counter-intuitive and implausible, and counter-intuitive and implausible benchmarking models do not appropriately "control for the cost impacts of undergrounding."

b) Does the final PEG model (Table Three) control for the added costs of serving urban environments? If yes, please explain.

Yes. Four variables in "the final PEG model," presented in Table Three of the PEG Report, control for the added costs of serving urban environments: 1) N x N; 2) D x D; 3) K x N; and 4) K x D.

In the cross section of investor-owned US utilities in PEG's (and PSE's) samples, there is a positive relationship between the overall size of a utility and its urban-ness. In other words, the largest utilities in PEG's and PSE's samples also tend to be the ones that serve large urban areas. This relationship is not surprising, because large urban areas clearly contain large numbers of electricity distribution customers and high levels of peak demand. Customer numbers and demands in large

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population centers will be reflected in the size of the US electricity distributors serving those urban areas.

There are two output measures in PEG's and PSE's econometric models: number of retail customers (N) and peak demand (D). Higher values of N and D measure increasing levels of customers and peak demand, respectively. The N x N and D x D variables represent the *squared* values of customer numbers and peak demand, respectively. These terms are standard in the translog functional form used by both PEG and PSE. For firms serving large numbers of customers and peak demand, the square terms N x N and D x D naturally increase at a more rapid rate than the N and D terms. All else equal, this implies that the coefficients on the squared N x N and D x D terms reflect the costs associated with the largest - and most urban – utilities in the US plus THESL sample, relative to the average firm in this sample. The coefficients on these terms therefore reflect and control for the impact of serving more urban territories in the US plus THESL sample.

This relationship can perhaps be clarified by considering a relatively simple numerical example. Consider two utilities, A and B, in two periods, 1 and 2. Utility A serves 100,000 customers in period 1 and utility B serves 1,000,000 customers in period 1. Between periods 1 and 2, assume customers grow by 1% for each utility.

For utility A, the 1% growth in customers corresponds to an increase in 1,000 customers (*i.e.* 100,000 * .01 = 1,000). For utility B, the 1% growth in customers corresponds to an increase of 10,000 customers (*i.e.* 1,000,000 * .01 = 10,000). A 1% growth rate for both A and B therefore leads to 10 times as many customers being added for utility B as for utility A. This is intuitive because utility B had 10 times as many customers as utility B in period 1. The same percentage increase in customer numbers for utilities A and B therefore leads to 10 times as many customers added for utility B as for utility A.

Now consider how the squared term, N x N, compares for utilities A and B in this same example. In period 1, the N x N term is equal to 10^{10} for utility A (*i.e.* $100{,}000^2 = (10^5)^2 = 10^{10}$) and 10^{12} for utility B (*i.e.* $1{,}000{,}000^2 = (10^6)^2 = 10^{12}$). In period 2, the N x N term will equal $1.0201 * 10^{10}$ for utility A (*i.e.* $101{,}000^2 = 1.0201 * 10^{10}$). The N x N term in period 2 equals $1.0201 * 10^{12}$ for utility B (*i.e.* $1{,}010{,}000^2 = 1.021 * 10^{12}$).

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Using these figures, it is easy to show that between periods 1 and 2, customers squared increased by 201,000,000 for utility A and by 20,100,000,000 for utility B. The change in customers squared for utility B is therefore 100 times greater than the change in customers squared for utility A (*i.e.* 20,100,000,000/201,000,000 = 100), even though both customers experienced 1% growth in customer numbers between periods 1 and 2.

This example shows that, for the squared N x N term, a 1% growth rate in customers does not lead to the same, proportional change in customer additions for utility A and utility B between the two periods. A 1% increase in customers leads to 100 times more change in measured (squared) output for utility B as it does for utility A even though utility B is only 10 times as large as utility A in period 1.

The squared output term N x N therefore tends to grow more rapidly over time for relatively large, and more urban, utilities in the US plus THESL sample. This in turn means the measured N x N variable is positively related to the size and urban-ness of distributors in the US plus THESL panel dataset (*i.e.* a dataset that includes both cross-sectional and time series data). All else equal, the coefficient on the N x N term therefore reflects the costs associated with serving larger and more urban territories within the sample, compared with smaller and less urban territories. Analogous logic applies to the D x D square term. All else equal, the coefficient on this term also reflects the costs associated with serving larger and more urban territories in the US plus THESL sample.

The coefficients on K x N and K x D also reflect urban characteristics. The K variable measures each distributor's capital service price in a year. A utility with higher values of K x N means the utility *simultaneously* faces a higher capital service price and serves a larger number of retail customers, compared with the average firm in the US plus THESL sample. With PEG's (and PSE's) capital service price measure, one utility will have higher than average capital service prices only when measured construction prices for that utility exceed sample average construction prices.

The prices for construction labor tend to be higher in urban territories. There is accordingly a positive relationship between the capital service price K and serving an urban territory. Please see the information

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provided in response to THESL Interrogatory 11 for further details.

As discussed, in the US plus THESL sample, there is also a positive relationship between output levels N and D and serving an urban territory. Thus, when a utility's construction prices/capital service prices and output are *both* greater than the sample mean, this is a strong indicator that the utility is serving an urban area. All else equal, the terms K x N and K x D therefore reflect the costs associated with serving larger and more urban territories in the US plus THESL sample.

Thus, four variables in the final PEG model will reflect and control for the costs of urban environments: 1) N x N; 2) D x D; 3) K x N; and 4) K x D. Table Three in the PEG Report shows that our estimated coefficients for all four of these variables are positive. Each variable is also highly significant statistically (at a greater than 1% significance level). The positive, highly significant estimates on all four of these variables are all evidence of a positive relationship between electricity distribution costs for the US-THESL sample and the extent to which a utility serves an urban area. The presence of these four variables in "the final PEG model" accordingly reflects and controls for serving urban territories.

Interestingly, the PSE model also estimates positive coefficients on its N x N and D x D variables, although the magnitudes of these coefficients are lower than in PEG's model, and the variables are not as significant statistically. In PSE's US Only model, the coefficients on N x N and D x D are 0.270 and 0.141 respectively. In Table Three of the PEG report, the coefficients on N x N and D x D are 0.6856 and 0.5932, respectively. The K x N and KxD variables are not significant in the PSE model.

c) Does the final PEG model (Table Three) control for the added costs of serving less dense rural environments? If yes, please explain.

Yes. All else equal, percent forestation will be positively correlated with less dense and more rural territories, so the PEG model does reflect and control for the costs of serving more rural environments.

1-THESL-11.

a) Please provide a price (or price range) for typical construction costs of one kilometer of direct buried underground cable line in a rural, agricultural area.

b) Please provide a price (or price range) for typical construction costs of one kilometer of underground line using encased concrete conduit in a highly urban area.

c) Please provide a price (or price range) for typical construction costs of one kilometer of an overhead line in a rural, agricultural area.

d) Please provide a price (or price range) for typical construction costs of one kilometer of an overhead line in a suburban area?

e) Please provide a price (or price range) for typical construction costs of one kilometer of an overhead line in a highly urban area?

a) PEG cannot provide a specific price, or price range, for this particular investment, but we can provide general quantitative information on the relationship between the population density of urban areas and construction costs.

PEG examined US Census Bureau data on population and land area (in square miles) for US population centers. These data were drawn from the *Patterns of Metropolitan and Micropolitan Population Change: 2000 to 2010*, CBSA Report Chapter 3 (CBSA=core based statistical area) at **http://www.census.gov/population/metro/data/pop_data.html**.

Using these Census Bureau data, PEG computed population density (*i.e.* area population divided by land area in square miles) for all identified metropolitan areas in the 48 states of the continental US. We determined the top ten and bottom ten metropolitan areas in the continental US in terms of population density.

PEG then obtained RS Means data on electric utility construction cost indices for each utility in the top ten and bottom ten groups, in terms of population density. We computed a population-weighted RS means construction cost index for the top ten US areas in terms of density, and a population-weighted RS Means construction cost index for the bottom ten US areas in terms of density. Comparing these two averages provides a measure of the relative differences in more-urban versus less-urban/more-rural electric utility construction costs in the US. PEG excluded Alaska and Hawaii from this analysis because their distance and isolation from other US population centers makes them special cases with respect to a variety of input and output price comparisons.

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This analysis is presented in Exhibit THESL-11. It can be seen that the ten most densely-populated metropolitan areas are: 1) New York City; 2) Los Angeles CA; 3) San Francisco CA; 4) Trenton-Ewing NJ; 5) Bridgeport-Stamford CT; 6) New Haven CT; 7) Chicago IL; 8) Boston MA; 9) Philadelphia PA; and 10) Tampa FL. The ten least densely-populated metropolitan areas (beginning with the least densely populated) are: 1) Flagstaff AZ; 2) Casper WY; 3) Lake Havasu AZ; 4) Rapid City SD; 5) Wenatchee WA; 6) Farmington NM; 7) Prescott AZ; 8) Grand Forks ND; 9) Great Falls MT; and 10) Bismarck, ND.

The populated-weighted average for the most densely populated US areas is 118.9. The populated-weighted average for the least densely populated US areas is 84.8. This indicates that construction costs are, on average, approximately 40.2% higher in the most urbanized parts of the US compared with the least-urbanized areas (*i.e.* 118.9/84.8 = 1.402).

This analysis is indicative only, and it does not control for differences in assets that may be installed to serve the most densely-populated areas compared with less-densely populated territories. Nevertheless, PEG believes this is strong evidence that there is a positive correlation between electric utility construction prices and the degree of urbanization throughout the US.

Moreover, it should be noted that PEG's benchmarking model controls for the higher costs of electric utility construction in urban areas. Construction cost price differences are reflected directly in the capital service price measures PEG developed for each US utility, and for THESL. Each utility's capital service price is included as an independent variable in PEG's cost benchmarking model. PEG's model therefore controls directly for differences in construction costs across service territories – and for relative differences in more-urban versus less-urban construction costs – in our econometric benchmarking model and in the econometric cost evaluations for THESL and the US sample.

b) Please see the response to part a).

c) Please see the response to part a).

d) Please see the response to part a).

e) Please see the response to part a).

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3.6 Area 6 – Metro / Urban Core

The selected metropolitan/core downtown urban area (Area 6) is located directly in the heart of downtown Toronto. The area is classified by PSE as a highly dense, mostly commercial area consisting of skyscrapers that serve as office towers, apartments and condominiums, hotels, and retail operations, including restaurants and large and small stores. The structures in this area range from 2 to 72 stories. The land mass of the area was measured at 0.28 square kilometers. An aerial image of Area 6 is shown in Figure 3-6.

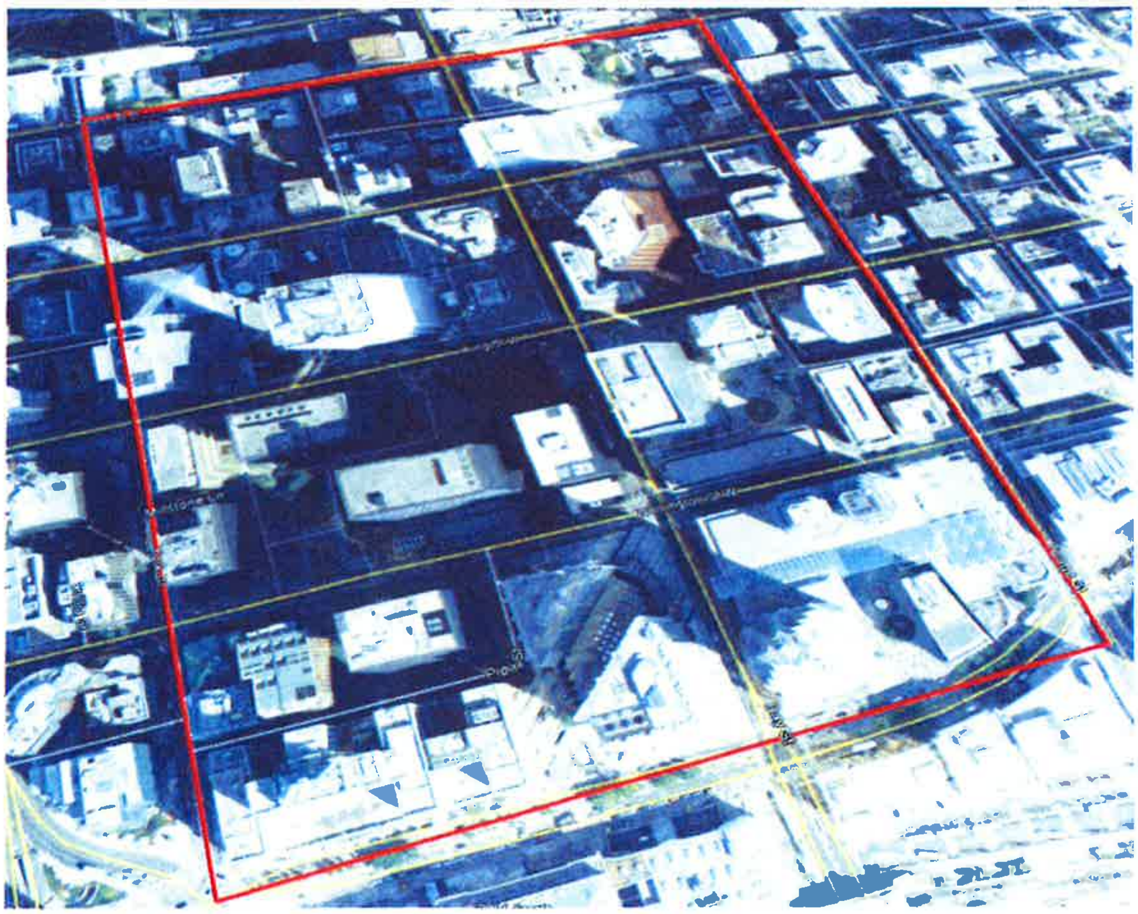


Figure 3-6 Core Downtown Area

Under PSE's assessment, approximately 55 properties were identified. The property with the largest floor space is estimated to be 251,000 square meters, while the property with the smallest floor space is estimated to be 670 square meters. Approximately 75% of the properties in the area were 10 stories or taller. The total commercial and residential floor space within the area is estimated to be 2,500,000 square meters.

year, but adjusted for the purchasing power parity (PPP) index. This translates the non-labour input price component into Canadian dollars. To construct the overall OM&A input price we weighted each index using a 70% labour and a 30% non-labour rate. This was the same weighting used by PEG in their benchmarking research.

The "residential percentage of sales volume" variable is also calculated based on data from FERC Form 1 for U.S. utilities and the Board's 4th Generation Incentive Regulation data for Ontario utilities. The percentage of residential volume compared to total volume is a proxy for the variance in electricity loads. Commercial and industrial customer loads tend to be more level across hours of the day. As the proportion of residential volume increases, distribution systems tend to increase their system peaks and load variability. This results in higher volatility in the loads served by the system.

The variable that measures the percentage of electric customers out of total gas and electric customers is derived from both the FERC Form 1 and the FERC Form 2. The FERC Form 2 data includes the number of gas customers served by a natural gas distributor. This variable measures the economies of scope available from serving both electric and gas customers. All Ontario electric distributors distribute only electricity, and have values of 100 percent for this variable.

Toronto Hydro serves the urban core of Toronto, Ontario. Serving a densely populated urban core presents challenges that are not present in suburban or rural settings. The urban core variable used in the total cost benchmarking models is a "binary" or "dummy" variable. This variable provides key information on the added costs of serving electricity to a highly urban area. All utilities are given a value of zero unless they serve the urban core of a city whose population is above one million (U.S. cities are designated by the 2010 U.S. census). Toronto Hydro is the only Ontario utility that serves an urban core of this magnitude. For more information on the cost impacts of serving highly dense metropolitan areas, please refer to PSE's report located in the Appendix of this report entitled, "Capital Requirements for Serving Developed Environments".

The percentage of electric distribution plant in total distribution plant measures the available economies of scope that result from being a vertically integrated utility, as opposed to a distribution-only utility. We expect distribution unit costs to be lower for utilities that also have transmission and generation activities. For U.S. utilities, data for this variable is found from the utilities' FERC Form 1s. All the Ontario utilities are designated as distribution-only utilities and have a value of 100 percent for this variable.

The customer density variable measures how many retail customers are served per length of line. The customer data is the same data that is used for the retail customer variable. The "miles of line" data for both U.S. and Ontario utilities is gathered through various editions of *Platts UDI Directory of Electric Producers and Distributors*. This variable measures the challenges of serving rural areas and having customers spread across a large service territory. The lower the customer density, the higher the expected costs. Again, for more information on the cost impacts of serving a lower density and rural area please refer to the report found in the Appendix.

The percentage of forestation variable is based on GIS (geographic information system) forestation maps. Such maps are matched with the areas served by each utility to create the variable. We would expect that the higher the level of forestation, the higher OM&A costs

2 Toronto Hydro Service Territory

Toronto Hydro is the largest municipal electrical distribution company in Canada, serving approximately 733,000 customers in the city of Toronto. Comparatively speaking, the service territory is very unique from other distributors in Ontario due to its significant population density. The evolution of the city and its supporting infrastructure is common to other major cities found in the United States.

2.1 City of Toronto

In 1834, Toronto became a civic incorporation. Mostly occupied by British and Irish immigrants at the time, Toronto's population grew by five times between 1831 and 1891. By the 1900s, more immigrants arrived from continental Europe, including Jews, Italians, and Ukrainians, followed by Germans, Poles, Hungarians, Slavs, Greeks, and Portuguese. By the 1920s, new suburban municipalities were appearing due to an overflowing city center of approximately 500,000 people. After World War II, Toronto's economy boomed and the population grew to over 1,000,000 by 1951. In the 1970s and 1980s, migrants from West India, South Asia and East Asia arrived. Present-day Toronto is made up of the former municipalities of Toronto, North York, Scarborough, York, Etobicoke, and East York, all of which merged into a six-municipality configuration in 1967. In 1998, the six municipalities were amalgamated into a single municipality, or the present-day City of Toronto. Currently, Toronto is Canada's largest municipality and North America's fourth largest city. According to data reported by the municipal government, the population of the City of Toronto was approximately 2.8 million in 2012, while the census metropolitan area population of the Toronto area was approximately 5.5 million in 2011.

Toronto is located on a shore plain of a harbor of Lake Ontario. The core downtown area of Toronto still resides along this shore line, while the rest of the city extends east, west, and north of the harbor. The city is intersected by three rivers and numerous tributaries, including the Humber River, the Don River, and the Rouge River, which have created densely forested ravines. The ravines have affected the original grid plan, and are noticeable on Finch Avenue, Leslie Street, Lawrence Avenue, and St. Clair Avenue. The ravines are useful for drainage of the city's storm sewer system, but often experience flooding during periods of heavy rain.

The City of Toronto was originally developed according to a small-town plot with a plain grid of straight streets. The straight grid pattern was extended as the city grew, but in 1834, uncoordinated private developments replaced the grid pattern. By the 1840s, the cityscape began to take shape. King Street was a main commercial east-west pathway, while Yonge Street served as the main north-south route. During the early 1900s, skyscrapers were being built and industry grew around Yonge Street, King Street, Queen Street, and Bay Street. A picture of present-day downtown Toronto is provided below.

Demand-side management (DSM) is a distribution activity regulated at the local jurisdictional level, not at the Federal level. Each jurisdiction sets its own methods for the accounting for and recovery of DSM activities, including direct expensing or recovery through of some or all of the costs in a regulatory asset. They may also have specific reporting requirements for DSM activities. Look to each company's tariff, and the local jurisdictional authority, for specific information on the treatment of DSM activities, and in which regulatory accounts such activity is charged.[6]

In an effort to provide conservative evidence in this proceeding and only address clear-cut necessary changes, PSE will assume that U.S. utilities report all CDM activities in the customer service and information expense category (even though this is likely not the case for all U.S. utilities). Thus, PSE included all of THESL's CDM expenses, which are projected at $51 million in 2015. Along with the smart meter expense inclusions for THESL, this assumption also makes the PSE Reply Report less favorable to THESL (e.g., if we were able to ascertain all CDM expenses for each utility and how they were recorded, THESL's results would most likely be better).

3.3 Adjustment #3: Model Specification with Urban Core and High Voltage Variables

PEG modified PSE's U.S. model by removing the urban core variable and including a high voltage capacity variable.[7] In this PSE Reply Report, following established industry practice, PSE removed PEG's high voltage variable, which is statistically insignificant and incorrectly signed, and re-included PSE's urban core variable, which is logical, signed correctly and statistically significant at a 99% confidence level.

The fact that the high voltage variable is signed incorrectly (it should be positive, but is negative in the PEG Report Corrections) and statistically insignificant at even the 90% confidence level disqualifies the variable from being included. Business condition variables that are incorrectly signed or statistically insignificant are not included in econometric benchmarking models. PEG's use of this variable, and its exclusion of the urban core variable, are not in-line with benchmarking best practices. PEG has stated the need for business condition variables to be correctly signed and statistically significant in a report to the Board. In a report dated March 20, 2008 "Benchmarking the Costs of Ontario Power Distributors" on page 52, PEG writes:

> All included business conditions were required to have elasticity estimates that were plausible (e.g. sensibly signed) and significantly different from zero. All variables found to be statistically significant were included in the final model. Since, additionally, we consider for inclusion only variables that are predicted by theory or that seem relevant on the basis of our industry experience, the model is not a 'black box' that confounds attempts at earnest appraisal.

In this proceeding, PEG has provided conflicting models with different signs for the high voltage variable, but in both models the variable is statistically insignificant. PEG's original December 2014 Report provided a model in Table Three that showed a statistically insignificant high voltage variable, but one that was positively signed. Then in PEG Report Corrections, PEG submitted a revised Table Three; this time the high voltage variable was <u>negatively</u> signed, but still statistically

[6] Correspondence from FERC.

[7] PEG also removed the percent undergrounding variable, although failed to mention this change or explain why the change occurred in the PEG Report.

Table 7 U.S. Total Cost Model Estimates

K= Capital Price
N= Number Retail Customers
D= Peak Demand
UD= Urban Core Dummy
PCE= Percent Electric Customers in Gas & Electric Customers
PRV= Percent Residential Deliveries in Total Deliveries
PDE= Percent Distribution Plant in Total Electric Plant
UG= Percent Distribution Plant Underground
ED= Elevation Standard Deviation
PF= Percent Forestation

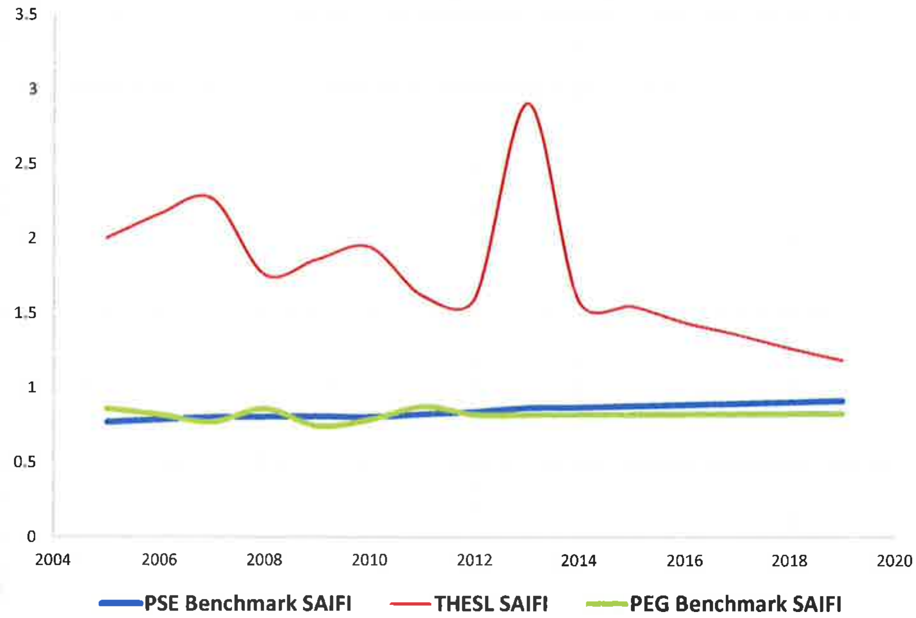
EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC	EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T STATISTIC
WK	0.555	143.656	PDE	0.122	7.596
KK	0.070	4.190			
KN	-0.010	-1.022	UG	-0.035	-2.305
KD	0.013	1.278			
			ED	0.013	2.140
N	0.732	30.652			
NN	0.270	3.274	PF	0.020	3.489
ND	-0.177	-2.197			
			Trend	0.003	2.872
D	0.220	8.916			
DD	0.141	1.677	Constant	20.098	1533.465
UD	0.016	5.687	System Rbar-Squared	0.958	
PCE	0.132	4.793	Sample Period:	2002-2012	
PRV	0.039	2.604	Number of Observations	880	

We note that cost is higher the higher the output quantities. At the sample mean, a 1% increase in the number of customers is estimated to raise cost by 0.73%. A one percent hike in peak demand is estimated to increase cost by 0.22%. As in the combined model, the number of customers served is clearly the dominant output-related cost driver.

The coefficients on the additional variables were also plausible. Utilities that serve an urban core with 1 million or more residents have higher costs than suburban utilities. Cost is also higher for utilities that only serve electric customers relative to those that serve both gas and electric customers. In addition, a utility that serves a more residential load, as measured by higher values

74

Figure 2 SAIFI: PSE, PEG, and Actual



Despite PEG's contention to the contrary, there is actually no meaningful difference between PEG's SAIDI benchmarks and those of PSE's. The only difference arises from the different time periods being compared. The PEG Report focused on the reliability performance scores in the past (2009-2011) rather than using the Custom IR projections to formulate conclusions. Although PEG has conducted this analysis, the PEG Report did not display the future reliability projections (THESL is projected to improve in this area). This is inconsistent with PEG's analysis of THESL's total costs, where PEG's conclusions were based on THESL's results through 2019.

PEG notes that it made a number of reliability data set revisions and exclusions to PSE's data, based on whether the data could be verified with the source document, or whether the value aligned with the current document. PEG states on page 38: "In PEG's opinion, these are serious errors and omissions." PEG's statement is exaggerated. The adjustments PEG made to PSE's reliability data are minor revisions. PSE made a good faith effort to gather data from hundreds of sources scattered around the internet over the course of many years. PEG made minor changes that did not have a meaningful impact on the results. The fact that PEG's results are so similar to PSE's testifies to this fact.

The consistency in THESL's reliability results is notable, given that two separate experts used different data sets, time periods, and models to derive them. While PSE is unconvinced that PEG's included variables should have replaced those in PSE's September model, the issue is of little consequence in this case, given the extreme similarity of results.[2] The similar results should provide the Board with a high level of confidence in the reliability benchmarking provided by PSE in this proceeding.

[2] PEG inserted cooling degree days, heating degree days, undergrounding, and precipitation into the models and took out percent forestation, customer density, wind, and the number of customers from the PSE models.

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ONTARIO ENERGY BOARD STAFF

UNDERTAKING NO. J2.14:

Reference(s):

To confirm that the numbers used in the PILs model for 2014 are USGAAP numbers.

RESPONSE:

Toronto Hydro confirms that the numbers used in the PILs model for 2014 are presented under IFRS.

The table below (Table 8) presents Toronto Hydro's historical (2011 – 2013) and forecasted (2014 – 2015) post-retirement benefit costs, including capitalized and expensed amounts.

Table 8: Post-Retirement Benefit Costs (2011-2014) ($ Millions)

	2011	2012	2013	2014	2015
Post-Benefit Costs	16.67	20.35	17.35	16.33	16.46
Capitalized Amounts	6.76	7.31	6.62	6.47	6.52
Expensed Amounts	9.94	13.05	10.72	9.86	9.94

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 79:

Reference(s): **Exhibit 4B, Tab 2, Schedule 2, p. 22**

THESL has recovered OPEBs in rates since 2000 both on a cash basis and on an accrual accounting basis. It is Board staff's understanding that THESL has recovered OPEBs on a cash basis up to May 1, 2006 and on an accrual basis thereafter:

a) Please confirm that Board staff's understanding is correct, or if not, please correct and explain;

b) Please complete the table below in a live Excel worksheet to show how much has been recovered for the period 2000 to 2013 relative to the actual cash benefit payments and how much is anticipated to be recovered in the forecast periods of 2014 to 2019;

OPEBs	Actual			Forecast			Grand Total
	2000 to	2013	Total	2014 to	2019	Total	
Amounts included in rates							
OM&A							
Capital expenditures							
Sub-total							
Paid benefit amounts							
Net excess amount included in rates greater than amounts actually paid							

c) Please describe what has been done with the recoveries in excess of the cash benefit payments.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

RESPONSE:

a) Since 2000, Toronto Hydro has recovered OPEB in rates under the accrual accounting basis. There was never a change from the cash basis to the accrual basis of accounting.

b) Please refer to the live Excel worksheet (IR_4B_OEBStaff_79B_20141105.xlsx) attached to this response. Consistent with its proposed rate framework, Toronto Hydro has not forecasted its operating expenses beyond the 2015 Test Year. For a discussion of the proposed rate framework please refer to Exhibit 1B, Tab 2, Schedule 3.

c) Recoveries in excess of the cash benefits have been used to fulfil the cost of ongoing utility operations.

IC - OEBStaff-79 part b - APPENDIX A

all amounts in '000's

col 2	col 3	col 4	col 5	col 6	col 7	col 8	col 9	col 10	col 11	col 12	col 13	col 14	col 15	col 16	col 17	col 18	col 19	col 20	col 21
OPEBs								**Actual**									**Forecast**		**Grand Total**
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**Total**	**2014**	**2015**	**Total**	
						C GAAP							US GAAP			US GAAP	IFRS		
Amounts Included in rates																			
OM&A	5,208	693	4,884	6,184	6,965	7,455	6,708	7,834	7,187	8,055	8,041	10,029	13,170	10,829	103,242	9,961	10,289	20,250	123,492
Capital Expenditures	-	122	139	231	352	472	619	874	1,099	1,342	1,192	1,412	1,614	1,832	11,300	2,030	2,223	4,253	15,553
Sub-Total	5,208	815	5,023	6,415	7,317	7,927	7,327	8,708	8,286	9,397	9,233	11,441	14,784	12,661	114,542	11,991	12,512	24,503	139,045
Paid benefits amounts	4,728	6,452	4,748	4,592	5,230	4,948	5,329	4,636	4,976	6,797	7,083	7,383	7,960	10,432	85,294	8,191	8,552	16,743	102,037
Net excess amount included in rates greater than amounts actually paid	480	(5,637)	275	1,823	2,087	2,979	1,998	4,072	3,310	2,600	2,150	4,058	6,824	2,229	29,248	3,800	3,960	7,760	37,008
		(1)																	

(1) Included in the net benefit cost for 2001 is a curtailment gain of $7,230 thousand dollars.

inferences; isn't that right? On two separate aspects of Toronto Hydro's performance?

MR. FENRICK: Yes, that's correct. They're two separate evaluations or models on separate distinctions, total cost versus SAIDI or SAIFI.

DR. KAUFMANN: Okay. Now, just in general, isn't the quality of statistical modelling and statistical estimation, isn't that improved by adding information to the sample, assuming that the information is accurate?

MR. FENRICK: In general, yes, I would agree with that statement, which is another reason why using the U.S. data set in combination with the Ontario, both on the reliability and the total cost, creates a larger data set with more observations, so, yes, I'd agree with that.

DR. KAUFMANN: Okay. Those are all my questions. Thank you.

MS. HELT: Thank you, Mr. Kauffman.

I do understand Board Staff has a few additional questions to follow up from yesterday with respect to Ms. Kwan and a few other members of Board Staff as well, so first we'll go with Ms. Kwan.

QUESTIONS BY MS. KWAN:

MS. KWAN: Okay. So I did have a couple of questions. The first one is on IR -- Board Staff IR 79. That's on other post-employment benefits. So in the response, Toronto Hydro indicated that since 2000 it has received $37 million in rates greater than the amounts paid for OPEBs, and it was also indicated that the excess recovery have been used to fulfill the cost of ongoing utility operations.

So I was just wondering if Toronto Hydro has ever considered setting aside the excess recovery for the purpose of paying out OPEB liabilities in the future.

MR. HERCZEG: Not to my knowledge.

MS. KWAN: Okay. And given that Toronto Hydro has used the excess recovery for ongoing operations, when Toronto Hydro is required to pay out the OPEB liability in the future, is Toronto Hydro going to ask for additional recoveries for OPEB from ratepayers?

MR. HERCZEG: Not to my knowledge.

MR. SMITH: I'm sorry, are you asking: What will Toronto Hydro do in a future application not covered by this application?

Because if that is the question, then I don't think that's an appropriate question.

MS. KWAN: We're asking if there is a plan, because part of the OPEB liability was already in rates in past applications.

MR. SMITH: I mean, I understand the fact that there is a difference between accrual and cash accounting and the treatment from a ratemaking perspective, which, of course, is a feature of accrual accounting generally.

But I don't think it's an appropriate question to ask what Toronto Hydro proposes by way of a 2020 rebasing at this time.

MS. KWAN: I guess we're not asking what their --

we're just seeing what's the general plan of OPEBs treatment in general, and not necessarily what they propose to do in a future application.

MR. SMITH: Well, Toronto Hydro's proposal in this proceeding is to recover OPEBs on an accrual basis, as reflected in the application. That is what the application is based upon.

MS. KWAN: Okay. But how about the excess recovery that's been recovered in the past? Are there any thoughts on that?

MR. SMITH: As Board Staff will be acutely aware, this is an issue that has come up a number of times, in which there have been a of variety of different suggestions made with respect to whether or not there ought to be a generic proceeding, but Toronto Hydro's application is filed on an accrual basis.

Which, subject to check, was also the basis on which 2011 rates were set and approved by the Board.

MS. KWAN: Okay. Then I'll move on to Board Staff IR 76 -- sorry, not 76, 86.

So in this IR, Toronto Hydro stated that it has decided not to apply for a disposition of the 36 million in account 1508 for actuarial losses upon the transition to IFRS, but Toronto Hydro wishes to reserve the right to maintain an account and potentially apply for disposition of a future actuarial loss.

So what would happen if Toronto Hydro has a future actuarial gain if interest rates and AA bond yields went up? Does Toronto Hydro plan on refunding the amount to ratepayers?

MR. HERCZEG: If at the next cost of service award, the next point in time, then that would be -- whatever the balance is at that time that's been audited, that would be forwarded in the application.

MS. KWAN: So it doesn't matter if it's a gain or a loss at that time? Because in the response that was provided, it only refers to a loss right now.

MR. SEAL: I think what we're indicating by this response, Ms. Kwan, is that currently we're not proposing to clear this OPEB account. We've indicated that over time the account value will change, as the underlying variables that impact this account will change.

Right now, we're not proposing to clear it.

MS. KWAN: But you may plan to propose to clear it in the future?

MR. SMITH: The company may make a decision in the future with respect to this deferral account.

MS. KWAN: Okay. If there are any staff reductions, that would lower the current service costs; would that affect the variance account?

MR. HERCZEG: There are many factors that go into the account. We do get evaluation by a third party, so I cannot at this point say that one factor would have -- what impact it would have.

MS. KWAN: Okay. And I have some questions on Board Staff IR 75 on PILs.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 28:

Reference(s): **Exhibit 1C, Tab 4, Schedule 2, p.22, Financial Statements 2013**

With respect to the first reference in note 13, THESL discloses a liability for OPEBs as at December 31, 2013 of $238,792,000.

a) Please state how much of this liability has been recovered through rates since 2000. THESL may wish to refer to undertaking TCJ1.19 in the Hydro One proceeding EB-2013-0416 for a suggestion as to how to complete its response;

b) Please provide the actuarial valuations used in the preparation of the year-end financial statements for the years 2010 through 2012.

RESPONSE:

a) From 2000 to 2013, approximately $114,542 of the liability for OPEBs has been recovered through rates.

b) Please refer to Appendices A to C to this Schedule. Please note that the OPEB liabilities associated with Energy Services Incorporated and LDC Unregulated as noted in the appendices are accounted for within the OPEB liability on the balance sheet of THESL. However, the OPEB costs associated with Toronto Hydro Corporation, Energy Services Incorporated and LDC Unregulated are accounted for in the income statements of the subsidiaries and are therefore not taken into account when calculating THESL rates.

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January 24, 2011

CONFIDENTIAL

Ms. Celine Arsenault-Smith
Toronto Hydro
14 Carlton Street
Toronto, ON M5B 1K5

Dear Celine:

RE: Fiscal 2010 Year-End Disclosure and Expense of the Post-Retirement Benefits for Employees of Toronto Hydro (the "Company") - Final

Further to your request, we have prepared updated year-end financial figures relating to Toronto Hydro's post-retirement benefits for reporting in its 2010 financial statements, including schedules with disclosures required under Section 3461 and accounting appendices G and H. The year-end financial figures presented herein were updated to reflect benefit payments made during Fiscal 2010 in respect of permanent LTD employees. **This letter replaces our initial letter dated January 14, 2010.**

It is our understanding that the Company has the following non-pension post-employment benefits: a sick leave program, life insurance, OMERS top-up pension, and extended health and dental benefits. There are no other non-pension post-employment benefits that we are aware of that would be subject to accounting treatment under CICA 3461.

We have enclosed the following:

Appendix G: Accounting Schedule for each of the four companies and Consolidated
Appendix H: CICA 3461 Disclosures for each of the four companies and Consolidated

Assumptions and Methods

All figures have been calculated using the same assumptions as those used in the valuation performed as at January 1, 2010 (and described in Appendix A of our report dated August 2010). Based on our discussions with the Company, we understand these assumptions still represent management's best estimates of future experience. The 2010 expense is based upon a 6.0% discount rate and the accrued benefit obligations ("ABO") at December 31, 2010 are based on a 5.75% discount rate, as instructed by the Company.

To determine the ABO at December 31, 2010, we re-ran our valuation at January 1, 2010 at a 5.75% discount rate, and projected forward the ABO and service cost figures with interest at 5.75% per annum, reflecting the actual benefit payments in Fiscal 2010.

Changes in Plan Provisions

We understand that there have not been any changes to the post-retirement non-pension benefits as outlined in Appendix D of our actuarial valuation report.

Expense Results Summary

A summary of the Fiscal 2010 expense, the balance sheet accrued benefit liability and the accrued benefit obligation as at December 31, 2010 is as follows:

	Fiscal 2010 Expense ($)	Accrued Benefit Liability at December 31, 2010 ($)	Accrued Benefit Obligation at December 31, 2010 ($)
Toronto Hydro-Electric System Limited	15,346,000	164,229,000	195,753,000
Toronto Hydro Corporation	133,000	3,107,000	1,397,000
Toronto Hydro-Energy Service Incorporation	184,000	1,841,000	2,080,000
Toronto Hydro – LDC Unregulated	83,000	720,000	797,000
Toronto Hydro-Consolidated	15,746,000	169,897,000	200,027,000

Representation

1. The most recent actuarial valuation of the Plan for accounting purposes was performed as at January 1, 2010. Extrapolations to December 31, 2010 have been performed in accordance with Section 3461 of the CICA Handbook.

   We have not been asked to provide an opinion nor have we provided an opinion regarding the actuarial assumptions. Emerging experience, differing from assumptions, will result in gains or losses that will be revealed in future actuarial valuations.

2. As is commonly the case in Canada for benefits other than pensions, there are no assets associated with the Company's Plans.

3. The expense figures for the year ending December 31, 2010 have been determined using the projected benefits method pro-rated on service, applied in conformity with Section 3461 of the CICA Handbook. These figures were extrapolated from the results of the valuation.

4. We understand that the Company elected the retroactive approach in adopting CICA Handbook Section 3461. The Company has adopted the Corridor Method for recognizing experience gains and losses. Under this accounting policy, the portion of the experience gains and losses that exceeds 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees and recognized in future years' expense.

5. The plan provisions are unchanged from those described in our actuarial valuation report dated August 2010. Please see Appendix D of that report for more details.

6. The results of the actuarial valuation and extrapolation have been based on the membership data as of January 1, 2010. Please refer to Appendix C of our report dated August 2010 for a summary of the membership data.

7. We are not aware of any matters or events between the date of our August 2010 valuation report and the date of this letter which would have a significant effect on the figures contained herein.

8. This letter has been prepared, and our opinions given, in accordance with accepted actuarial practice.

9. I am a member in good standing of the Canadian Institute of Actuaries. I understand that this letter will be used for audit evidence.

Should you have any questions or need further clarification, please call me.

Yours truly,

Gary E. Stoller

Gary E. Stoller, F.C.I.A.
(416) 383-6440

c.c. Nelsha Nanji, Morneau Sobeco

This letter and enclosures have been peer-reviewed by Philip Fosu, F.C.I.A.

Toronto Hydro - Consolidated
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	207,817,000	200,027,000	177,144,000	137,451,000
Experience (gain) loss			8,013,000	
Adjustment due to January 1, 2010 district changes			0	
Adjusted Accrued benefits at BOY	207,817,000	200,027,000	185,157,000	
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	4,133,000	3,908,000	3,485,000	2,539,000
Expected contributions (employer)	8,101,000	7,625,000	7,197,000	6,891,000
Contributions (employee)			0	0
Benefit payments	8,101,000	7,625,000	7,197,000	6,891,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	16.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	10.0
Exhibit I - Interest on accrued benefits				
Opening balance	207,817,000	200,027,000	185,157,000	137,451,000
Accrual for service	4,133,000	3,908,000	3,485,000	2,539,000
Benefit payments (mid-year)	(4,052,000)	(3,813,000)	(3,600,000)	0
Total	207,898,000	200,122,000	185,042,000	139,990,000
Interest	11,954,000	11,507,000	11,102,000	10,240,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	207,817,000	200,027,000	185,157,000	137,451,000
Accrual for service	4,133,000	3,908,000	3,485,000	2,539,000
Interest on accrued benefits	11,954,000	11,507,000	11,102,000	10,240,000
Benefit payments	(8,101,000)	(7,625,000)	(7,197,000)	(6,891,000)
Expected value at EOY	215,803,000	207,817,000	192,547,000	143,339,000
Actual value at EOY	215,803,000	207,817,000	200,027,000	177,144,000
Experience gain (loss)	0	0	7,480,000	(33,805,000)
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(27,319,000)	(27,952,000)	(12,654,000)	21,680,000
Other changes at BOY	0	0	(8,013,000)	0
Amortization amount	526,000	633,000	195,000	(529,000)
Changes during year	0	0	(7,480,000)	(33,805,000)
Experience gain/(loss) at EOY	(26,793,000)	(27,319,000)	(27,952,000)	(12,654,000)
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	4,133,000	3,908,000	3,485,000	2,539,000
Interest on accrued benefits	11,954,000	11,507,000	11,102,000	10,240,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	(5,000)	(156,000)	(296,000)	(296,000)
Amortization of Jan 1, 2001 amendment	5,000	182,000	195,000	195,000
Amortization of Jan 1, 2003 amendment	1,065,000	1,065,000	1,065,000	1,065,000
Amortization of experience (gains)/losses	526,000	633,000	195,000	(529,000)
Net expense	17,678,000	17,139,000	15,746,000	13,214,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	179,411,000	169,897,000	161,348,000	155,025,000
Adjustment due to January 1, 2010 district changes	0	0	0	0
Expense (Income) for the year	17,678,000	17,139,000	15,746,000	13,214,000
Funding contributions (total)	(8,101,000)	(7,625,000)	(7,197,000)	(6,891,000)
Closing balance at EOY	188,988,000	179,411,000	169,897,000	161,348,000
Exhibit VI - Reconciliation				
Accrued benefits at EOY	215,803,000	207,817,000	200,027,000	177,144,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	215,803,000	207,817,000	200,027,000	177,144,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	(5,000)	(10,000)	(166,000)	(462,000)
Jan 2001 past service cost	0	5,000	187,000	382,000
Jan 2003 past service cost	27,000	1,092,000	2,157,000	3,222,000
Experience (gains)/losses	26,793,000	27,319,000	27,952,000	12,654,000
	188,988,000	179,411,000	169,897,000	161,348,000

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Toronto Hydro - Electric System Limited
Post Retirement Benefits
APPENDIX G
Historical Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	203,341,000	195,753,000	172,280,000	134,026,000
Experience (gain) loss			7,511,000	
Adjustment due to January 1, 2010 district changes			1,518,000	
Adjusted Accrued benefits at BOY	203,341,000	195,753,000	181,309,000	134,026,000
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	3,992,000	3,775,000	3,367,000	2,419,000
Expected contributions (employer)	7,987,000	7,446,000	7,083,000	6,797,000
Contributions (employee)	0	0	0	0
Benefit payments	7,987,000	7,446,000	7,083,000	6,797,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	14.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	8.0
Exhibit I - Interest on accrued benefits				
Opening balance	203,341,000	195,753,000	181,309,000	134,026,000
Accrual for service	3,992,000	3,775,000	3,367,000	2,419,000
Benefit payments (mid-year)	(3,994,000)	(3,723,000)	(3,542,000)	(3,399,000)
Total	203,339,000	195,805,000	181,134,000	133,046,000
Interest	11,692,000	11,259,000	10,868,000	9,978,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	203,341,000	195,753,000	181,309,000	134,026,000
Accrual for service	3,992,000	3,775,000	3,367,000	2,419,000
Interest on accrued benefits	11,692,000	11,259,000	10,868,000	9,978,000
Benefit payments	(7,987,000)	(7,446,000)	(7,083,000)	(6,797,000)
Expected value at EOY	211,038,000	203,341,000	188,461,000	139,626,000
Actual value at EOY	211,038,000	203,341,000	195,753,000	172,280,000
Experience gain (loss)	0	0	7,292,000	32,654,000
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(29,022,000)	(29,809,000)	(15,372,000)	17,580,000
Other changes at BOY	0	0	(7,511,000)	0
10% Corridor	20,334,100	19,575,300	18,130,900	13,402,600
Total amount to be amortized	8,687,900	10,233,700	4,752,100	4,177,400
Amortization amount	668,000	787,000	366,000	(298,000)
Changes during year	0	0	(7,292,000)	(32,654,000)
Experience gain/(loss) at EOY	(28,354,000)	(29,022,000)	(29,809,000)	(15,372,000)
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	3,992,000	3,775,000	3,367,000	2,419,000
Interest on accrued benefits	11,692,000	11,259,000	10,868,000	9,978,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	0	(135,000)	(275,000)	(275,000)
Amortization of Jan 1, 2001 amendment	0	168,000	180,000	180,000
Amortization of Jan 1, 2003 amendment	840,000	840,000	840,000	840,000
Amortization of experience (gains)/losses	668,000	787,000	366,000	(298,000)
Net expense	17,192,000	16,694,000	15,346,000	12,844,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	173,477,000	164,229,000	154,448,000	148,401,000
Adjustment due to January 1, 2010 district changes	0	0	1,518,000	0
Expense (Income) for the year	17,192,000	16,694,000	15,346,000	12,844,000
Funding contributions (total)	(7,987,000)	(7,446,000)	(7,083,000)	(6,797,000)
Closing balance at EOY	182,682,000	173,477,000	164,229,000	154,448,000
Exhibit VI - Reconciliation				
Accrued benefits at EOY	211,038,000	203,341,000	195,753,000	172,280,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	211,038,000	203,341,000	195,753,000	172,280,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	0	0	(135,000)	(410,000)
Jan 2001 past service cost	0	0	168,000	348,000
Jan 2003 past service cost	2,000	842,000	1,682,000	2,522,000
Experience (gains)/losses	28,354,000	29,022,000	29,809,000	15,372,000
	182,682,000	173,477,000	164,229,000	154,448,000

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	2,493,000
Accrued benefit obligation as at December 31, 2010	29,415,000

1% Decrease	**$ Change**
Total of service and interest cost	(1,720,000)
Accrued benefit obligation as at December 31, 2010	(22,645,000)

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Toronto Hydro Corporation
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	1,416,000	1,397,000	2,347,000	1,738,000
Experience (gain) loss			300,000	
Adjustment due to January 1, 2010 district changes			(1,285,000)	
Adjusted Accrued benefits at BOY	1,416,000	1,397,000	1,362,000	
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	17,000	16,000	14,000	40,000
Expected contributions (employer)	79,000	76,000	109,000	92,000
Contributions (employee)	0	0	0	0
Benefit payments	79,000	76,000	109,000	92,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	16.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	11.0
Exhibit I - Interest on accrued benefits				
Opening balance	1,416,000	1,397,000	1,362,000	1,738,000
Accrual for service	17,000	16,000	14,000	40,000
Benefit payments (mid-year)	(40,000)	(38,000)	(55,000)	(46,000)
Total	1,393,000	1,375,000	1,321,000	1,732,000
Interest	80,000	79,000	79,000	130,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	1,416,000	1,397,000	1,362,000	1,738,000
Accrual for service	17,000	16,000	14,000	40,000
Interest on accrued benefits	80,000	79,000	79,000	130,000
Benefit payments	(79,000)	(76,000)	(109,000)	(92,000)
Expected value at EOY	1,434,000	1,416,000	1,346,000	1,816,000
Actual value at EOY	1,434,000	1,416,000	1,397,000	2,347,000
Experience gain (loss)	0	0	51,000	531,000
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	1,988,000	2,142,000	2,664,000	3,396,000
Other changes at BOY	0	0	(300,000)	0
10% Corridor	141,600	139,700	136,200	173,800
Total amount to be amortized	1,846,400	2,002,300	2,227,800	3,222,200
Amortization amount	(142,000)	(154,000)	(171,000)	(201,000)
Changes during year	0	0	(51,000)	(531,000)
Experience gain/(loss) at EOY	1,846,000	1,988,000	2,142,000	2,664,000
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	17,000	16,000	14,000	40,000
Interest on accrued benefits	80,000	79,000	79,000	130,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	(2,000)	(18,000)	(18,000)	(18,000)
Amortization of Jan 1, 2001 amendment	5,000	12,000	12,000	12,000
Amortization of Jan 1, 2003 amendment	217,000	217,000	217,000	217,000
Amortization of experience (gains)/losses	(142,000)	(154,000)	(171,000)	(201,000)
Net expense	175,000	152,000	133,000	180,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	3,183,000	3,107,000	4,368,000	4,280,000
Adjustment due to January 1, 2010 district changes	0	0	(1,285,000)	0
Expense (Income) for the year	175,000	152,000	133,000	180,000
Funding contributions (total)	(79,000)	(76,000)	(109,000)	(92,000)
Closing balance at EOY	3,279,000	3,183,000	3,107,000	4,368,000
Exhibit VI - Reconciliation				
Accrued benefits at BOY	1,434,000	1,416,000	1,397,000	2,347,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	1,434,000	1,416,000	1,397,000	2,347,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	0	(2,000)	(20,000)	(38,000)
Jan 2001 past service cost	0	5,000	17,000	29,000
Jan 2003 past service cost	1,000	218,000	435,000	652,000
Experience (gains)/losses	(1,846,000)	(1,988,000)	(2,142,000)	(2,664,000)
	3,279,000	3,183,000	3,107,000	4,368,000

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	15,000
Accrued benefit obligation as at December 31, 2010	201,000

1% Decrease	**$ Change**
Total of service and interest cost	(12,000)
Accrued benefit obligation as at December 31, 2010	(159,000)

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Toronto Hydro - Energy Services Incorporated
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	2,176,000	2,080,000	2,517,000	1,687,000
Experience (gain) loss			166,000	
Adjustment due to January 1, 2010 district changes			(870,000)	
Adjusted Accrued benefits at BOY	2,176,000	2,080,000	1,813,000	
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	76,000	72,000	64,000	80,000
Expected contributions (employer)	22,000	97,000	5,000	2,000
Contributions (employee)	0	0	0	0
Benefit payments	22,000	97,000	5,000	2,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	18.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	12.0
Exhibit I - Interest on accrued benefits				
Opening balance	2,176,000	2,080,000	1,813,000	1,687,000
Accrual for service	76,000	72,000	64,000	80,000
Benefit payments (mid-year)	(11,000)	(49,000)	(3,000)	(1,000)
Total	2,241,000	2,103,000	1,874,000	1,766,000
Interest	129,000	121,000	112,000	132,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	2,176,000	2,080,000	1,813,000	1,687,000
Accrual for service	76,000	72,000	64,000	80,000
Interest on accrued benefits	129,000	121,000	112,000	132,000
Benefit payments	(22,000)	(97,000)	(5,000)	(2,000)
Expected value at EOY	2,359,000	2,176,000	1,984,000	1,897,000
Actual value at EOY	2,359,000	2,176,000	2,080,000	2,517,000
Experience gain (loss)	0	0	(96,000)	(620,000)
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(208,000)	(208,000)	54,000	704,000
Other changes at BOY	0	0	(166,000)	0
10% Corridor	217,600	208,000	181,300	168,700
Total amount to be amortized	0	0	0	535,300
Amortization amount	0	0	0	(30,000)
Changes during year	0	0	(96,000)	(620,000)
Experience gain/(loss) at EOY	(208,000)	(208,000)	(208,000)	54,000
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	76,000	72,000	64,000	80,000
Interest on accrued benefits	129,000	121,000	112,000	132,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	(3,000)	(3,000)	(3,000)	(3,000)
Amortization of Jan 1, 2001 amendment	0	2,000	3,000	3,000
Amortization of Jan 1, 2003 amendment	8,000	8,000	8,000	8,000
Amortization of experience (gains)/losses	0	0	0	(30,000)
Net expense	210,000	200,000	184,000	190,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	1,944,000	1,841,000	2,532,000	2,344,000
Adjustment due to January 1, 2010 district changes	0	0	(870,000)	0
Expense (Income) for the year	210,000	200,000	184,000	190,000
Funding contributions (total)	(22,000)	(97,000)	(5,000)	(2,000)
Closing balance at EOY	2,132,000	1,944,000	1,841,000	2,532,000
Exhibit VI - Reconciliation				
Accrued benefits at EOY	2,359,000	2,176,000	2,080,000	2,517,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	2,359,000	2,176,000	2,080,000	2,517,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	(5,000)	(8,000)	(11,000)	(14,000)
Jan 2001 past service cost	0	0	2,000	5,000
Jan 2003 past service cost	24,000	32,000	40,000	48,000
Experience (gains)/losses	208,000	208,000	208,000	(54,000)
	2,132,000	1,944,000	1,841,000	2,532,000

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	39,000
Accrued benefit obligation as at December 31, 2010	429,000

1% Decrease	**$ Change**
Total of service and interest cost	(29,000)
Accrued benefit obligation as at December 31, 2010	(318,000)

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Toronto Hydro - LDC Unregulated
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	884,000	797,000	0	0
Experience (gain) loss			36,000	
Adjustment due to January 1, 2010 district changes			637,000	
Adjusted Accrued benefits at BOY	884,000	797,000	673,000	0
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	48,000	45,000	40,000	0
Expected contributions (employer)	13,000	6,000	0	0
Contributions (employee)	0	0	0	0
Benefit payments	13,000	6,000	0	0
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	14.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	8.0
Exhibit I - Interest on accrued benefits				
Opening balance	884,000	797,000	673,000	0
Accrual for service	48,000	45,000	40,000	0
Benefit payments (mid-year)	(7,000)	(3,000)	0	0
Total	925,000	839,000	713,000	0
Interest	53,000	48,000	43,000	0
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	884,000	797,000	673,000	0
Accrual for service	48,000	45,000	40,000	0
Interest on accrued benefits	53,000	48,000	43,000	0
Benefit payments	(13,000)	(6,000)	0	0
Expected value at EOY	972,000	884,000	756,000	0
Actual value at EOY	972,000	884,000	797,000	0
Experience gain (loss)	0	0	41,000	0
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(77,000)	(77,000)	0	0
Other changes at BOY	0	0	(36,000)	0
10% Corridor	88,400	79,700	67,300	0
Total amount to be amortized	0	0	0	0
Amortization amount	0	0	0	0
Changes during year	0	0	(41,000)	0
Experience gain/(loss) at EOY	(77,000)	(77,000)	(77,000)	0
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	48,000	45,000	40,000	0
Interest on accrued benefits	53,000	48,000	43,000	0
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	0	0	0	0
Amortization of Jan 1, 2001 amendment	0	0	0	0
Amortization of Jan 1, 2003 amendment	0	0	0	0
Amortization of experience (gains)/losses	0	0	0	0
Net expense	101,000	93,000	83,000	0
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	807,000	720,000	0	0
Adjustment due to January 1, 2010 district changes	0	0	637,000	0
Expense (Income) for the year	101,000	93,000	83,000	0
Funding contributions (total)	(13,000)	(6,000)	0	0
Closing balance at EOY	895,000	807,000	720,000	0
Exhibit VI - Reconciliation				
Accrued benefits at EOY	972,000	884,000	797,000	0
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	972,000	884,000	797,000	0
Less: Unamortized (gains)/losses				
July 2000 past service cost	0	0	0	0
Jan 2001 past service cost	0	0	0	0
Jan 2003 past service cost	0	0	0	0
Experience (gains)/losses	77,000	77,000	77,000	0
	895,000	807,000	720,000	0

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	21,000
Accrued benefit obligation as at December 31, 2010	186,000

1% Decrease	**$ Change**
Total of service and interest cost	(16,000)
Accrued benefit obligation as at December 31, 2010	(139,000)

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Appendix H

Post-Retirement Benefits other than Pension for Toronto Hydro - Consolidated CICA 3461 Disclosures

	Estimate 2011	2010	2009	2008
Accrued benefit obligation:				
Balance at beginning of year	200,027,000	177,144,000	137,451,000	176,269,000
Experience (gain) loss at beginning of year	0	8,013,000	0	0
Reduction in ABO due to sale of Telecom July 31, 2008	0	0	0	(294,000)
Current service cost	3,908,000	3,485,000	2,539,000	3,613,000
Past Service Cost	0	0	0	0
Interest cost	11,507,000	11,102,000	10,240,000	9,721,000
Benefits paid	(7,625,000)	(7,197,000)	(6,891,000)	(5,671,000)
Actuarial (gains)/losses	0	7,480,000	33,805,000	(46,187,000)
Plan amendments	0	0	0	0
Balance at end of year	207,817,000	200,027,000	177,144,000	137,451,000

Reconciliation of accrued benefit obligation to accrued benefits liability:

	Estimate 2011	2010	2009	2008
Accrued benefit obligation	207,817,000	200,027,000	177,144,000	137,451,000
Less: Unamortized net actuarial (gain)/loss	27,319,000	27,952,000	12,654,000	(21,680,000)
Unamortized past service costs	1,087,000	2,178,000	3,142,000	4,106,000
Post-employment benefits liability	179,411,000	169,897,000	161,348,000	155,025,000

Components for net periodic defined benefit costs:

	Estimate 2011	2010	2009	2008
Current service cost	3,908,000	3,485,000	2,539,000	3,613,000
Interest cost	11,507,000	11,102,000	10,240,000	9,721,000
Actuarial (gains)/ losses	0	15,493,000	33,805,000	(46,187,000)
Plan amendments	0	0	0	0
Elements of defined benefit costs before adjustment recognized in:	15,415,000	30,080,000	46,584,000	(32,853,000)
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	633,000	(15,298,000)	(34,334,000)	46,787,000
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	1,091,000	964,000	964,000	964,000
Defined benefit costs recognized	17,139,000	15,746,000	13,214,000	14,898,000

Significant assumptions

	Estimate 2011	2010	2009	2008
Accrued benefit obligation as of December 31:				
- Discount rate	5.75%	5.75%	6.00%	7.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Benefit costs for the years ended December 31:				
- Discount rate	5.75%	6.00%	7.50%	5.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity Analysis - Extended Health & Dental Care

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	2,568,000	(1,777,000)
Accrued benefit obligation as at December 31, 2010 (at 5.75%)	30,231,000	(23,262,000)

Sensitivity Analysis - Discount Rate for Disclosure Purposes

Assumed interest rates have a significant effect on the amounts reported for the total accrued benefit obligation and expense.
A one-percentage-point change in assumed interest rates would have the following effects for 2010:

	Increase $	Decrease $
Accrued benefit obligation as at December 31, 2010	(27,096,000)	35,140,000
Estimated expense for Fiscal 2011	(1,449,000)	3,197,000

Appendix H

Post-Retirement Benefits other than Pension for Toronto Hydro Electric System Limited CICA 3461 Disclosures

	Estimate 2011	2010	2009	2008
Accrued benefit obligation:				
Balance at beginning of year	195,753,000	172,280,000	134,026,000	171,382,000
Experience (gain) loss at beginning of year	0	7,511,000	0	0
Adjustment due to January 1 district changes	0	1,518,000	0	0
Current service cost	3,775,000	3,367,000	2,419,000	3,433,000
Interest cost	11,259,000	10,868,000	9,978,000	9,461,000
Benefits paid	(7,446,000)	(7,083,000)	(6,797,000)	(5,592,000)
Actuarial (gains)/losses	0	7,292,000	32,654,000	(44,658,000)
Plan amendments	0	0	0	0
Balance at end of year	203,341,000	195,753,000	172,280,000	134,026,000
Reconciliation of accrued benefit obligation to accrued benefits liability:				
Accrued benefit obligation	203,341,000	195,753,000	172,280,000	134,026,000
Less: Unamortized net actuarial (gain)/loss	29,022,000	29,809,000	15,372,000	(17,580,000)
Unamortized past service costs	842,000	1,715,000	2,460,000	3,205,000
Post-employment benefits liability	173,477,000	164,229,000	154,448,000	148,401,000
Components for net periodic defined benefit costs:				
Current service cost	3,775,000	3,367,000	2,419,000	3,433,000
Interest cost	11,259,000	10,868,000	9,978,000	9,461,000
Actuarial (gains)/ losses	0	14,803,000	32,654,000	(44,658,000)
Plan amendments	0	0	0	0
Elements of defined benefit costs before adjustment recognized in:	15,034,000	29,038,000	45,051,000	(31,764,000)
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	787,000	(14,437,000)	(32,952,000)	45,423,000
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	873,000	745,000	745,000	745,000
Defined benefit costs recognized	16,694,000	15,346,000	12,844,000	14,404,000
Significant assumptions				
Accrued benefit obligation as of December 31:				
- Discount rate	5.75%	5.75%	6.00%	7.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Benefit costs for the years ended December 31:				
- Discount rate	5.75%	6.00%	7.50%	5.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	2,493,000	(1,720,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	29,415,000	(22,646,000)

Prepared by Morneau Sobeco

1/25/2011

Appendix H

Post-Retirement Benefits other than Pension for Toronto Hydro Corporation CICA 3461 Disclosures

	Estimate 2011	2010	2009	2008
Accrued benefit obligation:				
Balance at beginning of year	1,397,000	2,347,000	1,738,000	2,299,000
Experience (gain) loss at beginning of year	0	300,000	0	0
Adjustment due to January 1 district changes	0	(1,285,000)	0	0
Current service cost	16,000	14,000	40,000	59,000
Interest cost	79,000	79,000	130,000	128,000
Benefits paid	(76,000)	(109,000)	(92,000)	(60,000)
Actuarial (gains)/losses	0	51,000	531,000	(688,000)
Plan amendments	0	0	0	0
Balance at end of year	1,416,000	1,397,000	2,347,000	1,738,000
Reconciliation of accrued benefit obligation to accrued benefits liability:				
Accrued benefit obligation	1,416,000	1,397,000	2,347,000	1,738,000
Less Unamortized net actuarial (gain)/loss	(1,988,000)	(2,142,000)	(2,664,000)	(3,396,000)
Unamortized past service costs	221,000	432,000	643,000	854,000
Post-employment benefits liability	3,183,000	3,107,000	4,368,000	4,280,000
Components for net periodic defined benefit costs:				
Current service cost	16,000	14,000	40,000	59,000
Interest cost	79,000	79,000	130,000	128,000
Actuarial (gains)/ losses	0	351,000	531,000	(688,000)
Plan amendments	0	0	0	0
Elements of defined benefit costs before adjustment recognized in:	95,000	444,000	701,000	(501,000)
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	(154,000)	(522,000)	(732,000)	523,000
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	211,000	211,000	211,000	211,000
Defined benefit costs recognized	**152,000**	**133,000**	**180,000**	**233,000**
Significant assumptions				
Accrued benefit obligation as of December 31:				
- Discount rate	5.75%	5.75%	6.00%	7.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Benefit costs for the years ended December 31:				
- Discount rate	5.75%	6.00%	7.50%	5.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	15,000	(12,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	201,000	(159,000)

Appendix H

Post-Retirement Benefits other than Pension for Toronto Hydro-Energy Service Incorporation CICA 3461 Disclosures

	Estimate 2011	2010	2009	2008
Accrued benefit obligation:				
Balance at beginning of year	2,080,000	2,517,000	1,687,000	2,294,000
Experience (gain) loss at beginning of year	0	166,000	0	0
Adjustment due to January 1 district changes	0	(870,000)	0	0
Current service cost	72,000	64,000	80,000	121,000
Interest cost	121,000	112,000	132,000	132,000
Benefits paid	(97,000)	(5,000)	(2,000)	(19,000)
Actuarial (gains)/losses	0	96,000	620,000	(841,000)
Plan amendments	0	0	0	0
Balance at end of year	**2,176,000**	**2,080,000**	**2,517,000**	**1,687,000**

Reconciliation of accrued benefit obligation to accrued benefits liability:

	2011	2010	2009	2008
Accrued benefit obligation				
Less: Unamortized net actuarial (gain)/loss	2,176,000	2,080,000	2,517,000	1,687,000
Unamortized past service costs	208,000	208,000	(54,000)	(704,000)
Post-employment benefits liability	24,000	31,000	39,000	47,000
	1,944,000	1,841,000	2,532,000	2,344,000

Components for net periodic defined benefit costs:

	2011	2010	2009	2008
Current service cost	72,000	64,000	80,000	121,000
Interest cost	121,000	112,000	132,000	132,000
Actuarial (gains)/ losses	0	262,000	620,000	(841,000)
Plan amendments	0	0	0	0
Elements of defined benefit costs before adjustment recognized in:	193,000	438,000	832,000	(588,000)
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	0	(262,000)	(650,000)	841,000
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	7,000	8,000	8,000	8,000
Defined benefit costs recognized	**200,000**	**184,000**	**190,000**	**261,000**

Significant assumptions

	2011	2010	2009	2008
Accrued benefit obligation as of December 31:				
- Discount rate	5.75%	5.75%	6.00%	7.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Benefit costs for the years ended December 31:				
- Discount rate	5.75%	6.00%	7.50%	5.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans. A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	39,000	(29,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	429,000	(318,000)

Appendix H

Post-Retirement Benefits other than Pension for
LDC Unregulated
CICA 3461 Disclosures

		Estimate 2011	2010
Accrued benefit obligation:			
	Balance at beginning of year	797,000	0
	Experience (gain) loss at beginning of year	0	36,000
	Adjustment due to January 1 district changes	0	637,000
	Current service cost	45,000	40,000
	Interest cost	48,000	43,000
	Benefits paid	(6,000)	0
	Actuarial (gains)/losses	0	41,000
	Plan amendments	0	0
	Balance at end of year	884,000	797,000
Reconciliation of accrued benefit obligation to accrued benefits liability:			
	Accrued benefit obligation	884,000	797,000
Less:	Unamortized net actuarial (gain)/loss	77,000	77,000
	Unamortized past service costs	0	0
	Post-employment benefits liability	807,000	720,000
Components for net periodic defined benefit costs:			
	Current service cost	45,000	40,000
	Interest cost	48,000	43,000
	Actuarial (gains)/ losses	0	77,000
	Plan amendments	0	0
	Elements of defined benefit costs before adjustment recognized in:	93,000	160,000
	Adjustments to recognize the long-term nature of employee future benefit costs:		
	- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	0	(77,000)
	- Difference between amortization of past service costs for the period and the actual plan amendments for the period	0	0
	Defined benefit costs recognized	93,000	83,000
Significant assumptions			
	Accrued benefit obligation as of December 31:		
	- Discount rate	5.75%	5.75%
	- Rate of compensation increase	4.00%	4.00%
	Benefit costs for the years ended December 31:		
	- Discount rate	5.75%	6.00%
	- Rate of compensation increase	4.00%	4.00%
	Assumed health care cost trend rates at December 31:		
	- Rate of increase in dental costs	4.00%	4.00%
	- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%
	- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%
	- Ultimate year (pre July 2000 retirements)	2016	2016
	- Rate of increase in health costs (other members)	8.50%	9.00%
	- Ultimate rate in health costs (other members)	5.00%	5.00%
	- Ultimate year (other members)	2019	2019

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	21,000	(16,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	186,000	(139,000)

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February 5, 2012

Ms. Celine Arsenault-Smith
Toronto Hydro
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Celine:

POST-RETIREMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2011 YEAR END DISCLOSURES AND ESTIMATED 2012 AND 2013 NET PERIODIC COST

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits:

- Extended health benefits for retirees and members on long-term disability;
- Dental benefits for retirees and members on long-term disability;
- Life insurance benefits for retirees;
- Sick leave benefits; and
- OMERS top up pension.

This letter and appendices have been prepared for the Company for the following purposes:

- Determining the final calculation of the 2011 net periodic expense to be reported in the Company's 2011 financial statements;

- Providing the required information for year-end disclosure purposes as of December 31, 2011 to be reported in the Company's 2011 financial statements; and

- Determining an estimate of 2012 and 2013 net periodic benefit cost.

The information contained in this letter and appendices is presented in thousands of Canadian dollars and is in respect of the benefits mentioned above only.

All valuation results and accounting calculations presented in this letter and appendices were prepared in accordance with the following accounting standards:
- 2011 net periodic expense and year-end disclosures – in accordance with Canadian GAAP (Canadian Institute of Chartered Accountants Handbook Section 3461)
- Estimated net period benefit cost for 2012 and 2013 – in accordance with US GAAP (FASB Accounting Standards Codification 715)

The year-end disclosure obligations are based on the January 1, 2010 actuarial valuation conducted by Morneau Shepell.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2010 actuarial valuation report prepared by Morneau Shepell (dated August 2010) for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- Results are based on the most recent valuation of the post-retirement and post-employment benefit programs. The valuation was performed as at January 1, 2010 by the previous actuarial consultants, Morneau Shepell, and we have relied on all the data and information including plan provisions and membership data, as being complete and accurate. We have not independently verified the accuracy or completeness of the data or information used for the January 1, 2010 actuarial valuation.
- The measurement date used for fiscal 2011 year-end disclosure is December 31, 2011.
- The 2011 benefit cost is based upon discount rate of 5.75% per annum and the accrued benefit obligation ("ABO") at December 31, 2011 is based upon discount rate of 4.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2010 and at December 31, 2011, respectively.
- With the exception of the discount rate, the actuarial methods and assumptions used for the determination of the 2011 net periodic benefit cost and December 31, 2011 obligation are consistent with those used for the 2010 disclosures.
- Service costs and ABO as of December 31, 2011 were extrapolated from the full January 1, 2010 valuation results assuming that there are no experience gains and losses other than from actual benefit payments being different from expected and from changes in the assumptions during the extrapolation period such as changes in the discount rate.

DISCLOSURE RESULTS SUMMARY

The summary of Fiscal 2011 net periodic benefit costs, the balance sheet accrued benefit liability and the ABO as at December 31, 2011, under Canadian GAAP are as follows (in $000s):

	Fiscal 2011 Net Periodic Benefit Costs	***Accrued Benefit Asset/(Liability) at December 31, 2011***	***ABO at December 31, 2011***
Toronto Hydro-Electric System Limited	$ 16,694	$ (173,542)	$ 239,064
Toronto Hydro Corporation	152	(3,171)	1,665
Toronto Hydro-Energy Service Incorporation	200	(2,017)	2,558
Toronto Hydro-LDC Unregulated	93	(811)	1,039
Toronto Hydro – Consolidated	17,139	(179,541)	244,326

- Actual benefit payments for 2011 of $7,495,000 are based on information provided by the Company on January 26, 2012. We have projected 2012 and 2013 benefit payments based on the valuation assumptions.

TRANSITION TO US GAAP

- We understand that the transition to US GAAP will result in all actuarial gains and losses and prior service costs to be fully recognized immediately in other comprehensive income as at the transition date, January 1, 2011. We understand that US GAAP will be adopted for financial reporting effective January 1, 2012 (with a provision of Fiscal 2011 comparative figures).
- On an ongoing basis, actuarial gains and losses will be reflected in the statement of comprehensive income. To the extent that they exceed 10% of the accumulated benefit obligation, these gains and losses will be recognized over the expected average remaining service period of active employees participating in the plans.
- On an ongoing basis, prior service costs will be reflected in the statement of comprehensive income, and recognized through expense over a straight line basis over the average service period (to full eligibility) of employees active at the date of amendment.
- As instructed by Toronto Hydro, we have assumed that all accounting methods and policies under US GAAP will be consistent with those applied under current Canadian GAAP. Additional disclosure items under US GAAP include a split of current and non-current liability.

OTHER COMMENTS

- We understand that the post-retirement benefit plan is not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.
- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2010 that would materially affect the results of our valuations.

* * * * *

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other postretirement benefit plans.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are not other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The calculations for the 2011 disclosures have been made in accordance with Section 3461 of the CICA Handbook, with which we are familiar. This report has been prepared in accordance with the reporting requirements of the CIA/CICA Joint Policy Statement.

In preparing the results presented in this letter (including the attached appendices), we have relied upon information provided to us regarding plan provisions, postretirement welfare plan costs, plan participants, plan assets and actuarial results prepared by Morneau Shepell. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The actuarial assumptions and the accounting policies and methods employed in the development of the pension cost have been selected by the Toronto Hydro management as representing their best estimates of future contingent events. As is required under the CICA accounting standards, the assumptions are not intended to include any provision for adverse deviations and we do not express any opinion on them. FASB ASC 715 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its periodic financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

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Enclosures

cc: Diane Low, Shirley Powell, Alex Park — Toronto Hydro
Olga Baliakina, Ken Chapman — Towers Watson

Post-Employment Benefits Plans - 2011 CICA 3461 Disclosures ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	December 31, 2010				
Funded status	(195,753)	(1,397)	(2,080)	(797)	(200,027)
Unamortized prior service costs					
July 2000 past service costs	(135)	(20)	(11)	-	(166)
Jan 2001 past service costs	168	17	2	-	187
Jan 2003 past service costs	1,682	435	40	-	2,157
Unamortized net actuarial (gains)/losses	29,809	(2,142)	208	77	27,952
Accrued benefit asset (liability)	(164,229)	(3,107)	(1,841)	(720)	(169,897)
Change in accrued benefit obligation	2011				
Accrued benefit obligation at beginning of year	195,753	1,397	2,080	797	200,027
Service cost	3,775	16	72	45	3,908
Interest cost	11,259	79	121	48	11,507
Actuarial (gain) loss	35,658	261	309	151	36,379
Benefits paid	(7,381)	(88)	(24)	(2)	(7,495)
Accrued benefit obligation at end of year	239,064	1,665	2,558	1,039	244,326
Change in plan assets	2011				
Fair value of plan assets at beginning of year	-	-	-	-	-
Actual return on plan assets	-	-	-	-	-
Employer contribution	7,381	88	24	2	7,495
Plan participants' contributions	-	-	-	-	-
Benefits paid	(7,381)	(88)	(24)	(2)	(7,495)
Fair value of plan assets at end of year	-	-	-	-	-
Net Periodic Benefit Cost	2011				
Service cost	3,775	16	72	45	3,908
Interest cost	11,259	79	121	48	11,507
Actuarial (gain)/loss during current period	35,658	261	309	151	36,379
Other adjustments to Allocate Costs to Period in which Service is Rendered:					
- Amortization of net (gain) loss	(34,871)	(415)	(309)	(151)	(35,746)
- Amortization of prior service cost					-
July 2000 past service costs	(135)	(18)	(3)	-	(156)
Jan 2001 past service costs	168	12	2	-	182
Jan 2003 past service costs	840	217	8	-	1,065
Total Net periodic benefit cost	16,694	152	200	93	17,139
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	December 31, 2011				
Funded status	(239,064)	(1,665)	(2,558)	(1,039)	(244,326)
Unamortized prior service costs					
July 2000 past service costs	-	(2)	(8)	-	(10)
Jan 2001 past service costs	-	5	-	-	5
Jan 2003 past service costs	842	218	32	-	1,092
Unamortized net actuarial (gains)/losses	64,680	(1,727)	517	228	63,698
Accrued benefit asset (liability)	(173,542)	(3,171)	(2,017)	(811)	(179,541)
Additional information at December 31, 2011					
Average future working lifetime	13.0	13.0	13.0	13.0	13.0
Expected benefit payments for 2012	7,987	79	22	13	8,101
Key Asumptions					
Discount rate as at December 31, 2011 (for Dec 31, 2011 ABO)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate as at December 31, 2010 (for 2011 Benefit Cost)	5.75%	5.75%	5.75%	5.75%	5.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Assumed medical and dental cost trend rate at December 31, 2011					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	7.00%	7.00%	7.00%	7.00%	7.00%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	8.50%	8.50%	8.50%	8.50%	8.50%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2011					
1% point increase	2,651	15	43	24	2,733
1% point decrease	(1,818)	(12)	(33)	(17)	(1,880)
Effect on accrued benefit obligation at December 31, 2011					
1% point increase	35,923	240	528	242	36,933
1% point decrease	(27,655)	(190)	(391)	(181)	(28,417)
Sensitivity to Changes in Discount Rate Assumption					
Effect on estimated 2012 Net Periodic Benefit Cost					
1% point increase	(2,950)	(21)	(37)	(22)	(3,030)
1% point decrease	3,355	25	46	23	3,449
Effect on accrued benefit obligation at December 31, 2011					
1% point increase	(32,384)	(226)	(347)	(141)	(33,098)
1% point decrease	41,998	293	449	183	42,923

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January 13, 2013

Ms. Aida Cipolla
Toronto Hydro
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Aida:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2012 YEAR END DISCLOSURES AND ESTIMATED 2013 AND 2014 NET PERIODIC COST UNDER US GAAP

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on long-term disability;
- Dental benefits for retirees and members on long-term disability;
- Life insurance benefits for retirees;
- Sick leave benefits; and
- OMERS top up pension.

This letter and appendices have been prepared for the Company for the following purposes:

- Determining the final calculation of the 2012 net periodic benefit cost to be reported in the Company's 2012 financial statements;

- Providing the required information for year-end disclosure purposes as of December 31, 2012 to be reported in the Company's 2012 financial statements; and

- Determining an estimate of 2013 and 2014 net periodic benefit cost.

The information contained in this letter and appendices is presented in thousands of Canadian dollars and is in respect of the benefits mentioned above only.

All valuation results and accounting calculations presented in this letter and appendices were prepared in accordance with US GAAP (FASB Accounting Standards Codification 715).

The 2012 net periodic benefit cost is consistent with the 2012 net periodic benefit cost provided in our 2011 disclosure letter dated February 5, 2012. The 2012 year-end disclosure obligations and extrapolations for 2013 and 2014 are based on the January 1, 2012 actuarial valuation conducted by Towers Watson.

In 2012, the Company implemented exit programs resulting in the termination of employees in 2012 and 2013. As directed by the company, the impact of the programs was treated as actuarial gains/losses as at December 31, 2012 in the financial accounting for the Plans under US GAAP.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2012 actuarial valuation report prepared by Towers Watson for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- The measurement date used for fiscal 2012 year-end disclosure is December 31, 2012.
- The 2012 benefit cost is based on a discount rate of 4.75% per annum and the accrued benefit obligation ("ABO") at December 31, 2012 is based on a discount rate of 4.25% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2011 and at December 31, 2012, respectively.
- The actuarial methods and assumptions used for the determination of the 2012 net periodic benefit cost are consistent with those used for the 2011 disclosures.
- With the exception of the discount rate, the actuarial methods and assumptions used to determine the December 31, 2012 obligation are consistent with those used for the January 1, 2012 valuation presented on December 12, 2012.
- The obligation as of December 31, 2012 and the 2013 and 2014 expense estimates are based on extrapolations from the January 1, 2012 valuation results, assuming that there are no experience gains and losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

DISCLOSURE RESULTS SUMMARY

The summary of Fiscal 2012 net periodic benefit costs, the ABO and accumulated other comprehensive income ("AOCI") as at December 31, 2012, under US GAAP are as follows (in $000s):

	Fiscal 2012 Net Periodic Benefit Costs	***ABO at December 31, 2012***	***AOCI at December 31, 2012***
Toronto Hydro-Electric System Limited	$ 20,354	$ 247,777	$ 61,823
Toronto Hydro Corporation	199	2,076	(1,194)
Toronto Hydro-Energy Service Incorporation	245	2,928	675
Toronto Hydro-LDC Unregulated	121	1,109	195
Toronto Hydro – Consolidated	20,919	253,890	61,499

- Actual benefit payments for 2012 of $8,069,000 are based on information provided by the Company on January 8, 2013. We have projected 2013 and 2014 benefit payments based on the valuation assumptions.

ACCOUNTING METHODS

- Actuarial gains and losses will be reflected in the statement of comprehensive income. To the extent that they exceed 10% of the accumulated benefit obligation, these gains and losses will be recognized over the expected average remaining service period of active employees participating in the plans.

- Prior service costs will be reflected in the statement of comprehensive income, and recognized through expense over a straight line basis over the average service period (to full eligibility) of employees active at the date of amendment.

OTHER COMMENTS

- The Company transitioned to US GAAP from Canadian GAAP for financial reporting effective January 1, 2012. Please refer to the 2011 disclosure letter dated February 5, 2012 for additional details.

- We understand that the post-retirement benefit plan is not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.

- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2012 that would materially affect the results of our valuations.

*****

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other postretirement benefit plans.

In preparing the results presented in this letter (including attached exhibits), we have relied upon information provided to us regarding plan provisions, actual benefit payments, historical plan costs and plan participants. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The actuarial assumptions and the accounting policies and methods employed in the development of the pension and postretirement plan costs have been selected by the Toronto Hydro management as representing their best estimates of future contingent events. The assumptions are not intended to include any provision for adverse deviations, and we do not express any opinion of them. FASB ASC 715 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its periodic financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

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Enclosures

cc: Lance Lugsdin, Shirley Powell, Helen Macdonald — Toronto Hydro
Olga Baliakina, Mitchell Coviensky — Towers Watson

Post-Employment Benefits Plan - US GAAP - 2012 Disclosure ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Funded status			January 1, 2012		
Funded status	(239,064)	(1,665)	(2,558)	(1,039)	(244,326)
Current vs. Non-Current OPEB Liability			January 1, 2012		
Current	(7,804)	(77)	(21)	(13)	(7,915)
Non-Current Liability	(231,260)	(1,588)	(2,537)	(1,026)	(236,411)
Total	(239,064)	(1,665)	(2,558)	(1,039)	(244,326)
Amounts Recognized in Accumulated Other Comprehensive Income			January 1, 2012		
Prior service (credit)/cost					
July 2000 past service costs	-	(2)	(8)	-	(10)
Jan 2001 past service costs	-	5	-	-	5
Jan 2003 past service costs	842	218	32	-	1,092
Net actuarial (gain)/loss	64,680	(1,727)	517	228	63,698
Total	65,522	(1,506)	541	228	64,785
Change in Accumulated Benefit Obligation (ABO)			2012		
Accumulated benefit obligation at beginning of year	239,064	1,665	2,558	1,039	244,326
Service cost	4,976	21	95	59	5,151
Interest cost	11,402	78	125	52	11,657
Actuarial (gain) loss	277	412	159	(23)	825
Benefits paid	(7,942)	(100)	(9)	(18)	(8,069)
Accumulated benefit obligation at end of year	247,777	2,076	2,928	1,109	253,890
Change in Plan Assets			2012		
Fair value of plan assets at beginning of year	-	-	-	-	-
Actual return on plan assets	-	-	-	-	-
Employer contribution	7,942	100	9	18	8,069
Plan participants' contributions	-	-	-	-	-
Benefits paid	(7,942)	(100)	(9)	(18)	(8,069)
Fair value of plan assets at end of year	-	-	-	-	-
Net Periodic Benefit Cost			2012		
Service cost	4,976	21	95	59	5,151
Interest cost	11,402	78	125	52	11,657
Amortization of prior service cost					-
July 2000 past service costs	-	(2)	(3)	-	(5)
Jan 2001 past service costs	-	5	-	-	5
Jan 2003 past service costs	840	217	8	-	1,065
Amortization of net (gain) loss	3,136	(120)	20	10	3,046
Net periodic benefit cost	20,354	199	245	121	20,919
Funded status			December 31, 2012		
Funded status	(247,777)	(2,076)	(2,928)	(1,109)	(253,890)
Current vs. Non-Current OPEB Liability			December 31, 2012		
Current	(9,790)	(79)	(37)	(19)	(9,925)
Non-Current Liability	(237,987)	(1,997)	(2,891)	(1,090)	(243,965)
Total	(247,777)	(2,076)	(2,928)	(1,109)	(253,890)
Amounts Recognized in Accumulated Other Comprehensive Income			December 31, 2012		
Prior service (credit)/cost					
July 2000 past service costs	-	-	(5)	-	(5)
Jan 2001 past service costs	-	-	-	-	-
Jan 2003 past service costs	2	1	24	-	27
Net actuarial (gain)/loss	61,821	(1,195)	656	195	61,477
Total	61,823	(1,194)	675	195	61,499
Additional Information					
Average future working lifetime as at December 31, 2012	18	15	13	15	
Average future working lifetime as at December 31, 2011	13	13	13	13	
Key Asumptions					
Discount rate as at December 31, 2012 (used for Dec 31/12 ABO)	4.25%	4.25%	4.25%	4.25%	4.25%
Discount rate as at December 31, 2011 (used for 2012 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%	4.0%
Assumed medical and dental cost trend rate at December 31, 2012					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Medical cost trend rate assumed for next year	6.5%	6.5%	6.5%	6.5%	6.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Medical cost trend rate assumed for next year	8.0%	8.0%	8.0%	8.0%	8.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2012					
1% point increase	2,461	12	39	22	2,534
1% point decrease	(2,164)	(9)	(33)	(17)	(2,223)
Effect on accrued benefit obligation at December 31, 2012					
1% point increase	31,479	221	477	170	32,347
1% point decrease	(27,614)	(198)	(417)	(151)	(28,380)
Sensitivity to Changes in Discount Rate Assumption					
Effect on estimated 2013 Net Periodic Benefit Cost					
1% point increase	(2,546)	(39)	(51)	(17)	(2,653)
1% point decrease	4,595	22	68	34	4,719
Effect on accrued benefit obligation at December 31, 2012					
1% point increase	(38,334)	(307)	(545)	(196)	(39,382)
1% point decrease	47,039	372	682	251	48,344
Projection of Benefit Payments					
2013	9,996	81	38	19	10,134
2014	8,039	82	40	22	8,183
2015	8,238	85	44	25	8,392
2016	8,912	85	51	28	9,076
2017	9,354	83	57	30	9,524
2018-2022	54,821	450	461	180	55,912

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 72:

Reference(s): **Exhibit 4A, Tab 4, Schedule 7, Towers Watson actuarial report**

The above reference provides calculations in accordance with US GAAP. THESL has applied for rates under IFRS.

Please provide an analysis that compares the 2014 and 2015 projections under US GAAP with IFRS. In the event, there are any differences arising from this analysis, please state whether or not THESL would consider it necessary to update its application to reflect them. If not, please explain why not.

RESPONSE:

OPEB projections for 2014 are provided under US GAAP and those for 2015 are provided under IFRS, consistent with Toronto Hydro's transition to IFRS on January 1, 2015. Please refer to Appendix A to this response for a copy of the IFRS actuarial report as at December 31, 2013. This report includes IFRS projections for 2015 that were included in the Application.

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January 16, 2014

Mr. Daniel Paquin
Toronto Hydro Corporation
14 Carlton Street
Toronto, ON
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Dear Dan:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2013 YEAR-END DISCLOSURES AND ESTIMATED 2014 AND 2015 BENEFIT EXPENSE UNDER INTERNATIONAL ACCOUNTING STANDARDS

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on total and permanent long-term disability;
- Dental benefits for retirees and members on total and permanent long-term disability;
- Life insurance benefits for retirees;
- Vested and non-vested accumulating sick leave benefits;
- OMERS top up pension; and
- Executive retirement allowances.

This letter and appendices have been prepared for the Company, for the following purposes:

- Determining the final calculation of the 2013 benefit expense under International Financial Reporting Standards (IFRS) in accordance with International Accounting Standards Section 19 revised in 2011;
- Providing the required information for year-end disclosure purposes as of December 31, 2013 under IAS 19 rev. 2011; and
- Determining an estimate of 2014 and 2015 benefit expense under IAS 19 rev. 2011.

The information contained in this letter and appendices is presented in thousands of Canadian dollars, and is in respect of the benefits mentioned above only.

The 2013 benefit expense was determine based on the 2013 benefit expense provided in our letter dated January 15, 2013, with updates for immediate recognition of (gains)/losses related to the retirement allowance and the accumulating sick leave benefits plans. The 2013 year-end disclosure obligations and extrapolations for 2014 and 2015 are based on the results of the January 1, 2012 actuarial valuation.

In 2013, the Company chose to include an obligation in respect of two executive retirement allowances (one of which is considered an incentive plan under IFRS, and the other considered a post-employment benefit under IFRS) granted to one key employee. As directed by the company, the impact of this change was recognized as part of the service cost in expense as at June 30, 2013 in the financial accounting for the Plans under IFRS for the Toronto Hydro Corporation division. Please refer to our email dated July 18, 2013 for additional information.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2012 actuarial valuation report prepared by Towers Watson for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- The measurement date used for Fiscal 2013 year-end financial reporting is December 31, 2013.
- The 2013 benefit expense is based on a discount rate of 4.25% per annum and the defined benefit obligation ("DBO") at December 31, 2013 is based on a discount rate of 4.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2012 and December 31, 2013 respectively.
- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2013 net periodic benefit cost and the December 31, 2013 obligation are consistent with those used for the 2012 disclosures.
- The obligation as of December 31, 2013 and the 2014 and 2015 expense estimates are based on extrapolations from the January 1, 2012 valuation results for the medical, dental, life insurance, accumulating sick leave and OMERS benefits plans, and the June 30, 2013 valuation results for the retirement allowance benefit plans, assuming that there are no experience gains or losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

ACCOUNTING METHODS

- The information presented assumes that the transition date (between IAS 19 rev. 2008 and IAS 19 rev. 2011) is January 1, 2013.
- Under IAS 19 rev. 2011, we understand that Toronto Hydro has determined that both the non-vested accumulating sick leave benefits plan and the vested accumulating sick leave benefits plan should be included for post-employment benefits reporting. As such, these benefits are included in the financial information under IAS 19 rev. 2011 presented in this letter.
- As directed by the Company, as of January 1, 2013, upon transition from IAS 19 rev. 2008 to IAS 19 rev. 2011, all unrecognized gains and losses were fully recognized in other comprehensive income. As such there were no further unrecognized actuarial gains and losses reflected in the defined benefit liability at January 1, 2013 under IAS 19 rev. 2011.
- On an ongoing basis, actuarial gains and losses for all benefit plans other than the accumulating sick leave benefits plans and the one executive retirement allowance considered to be an incentive plan will be immediately recognized in other comprehensive income. Actuarial gains and losses for the accumulating sick leave benefits plans and the one executive retirement allowance considered to be an incentive plan will be recognized immediately in expense.
- On an ongoing basis, the impact of plan changes will be immediately recognized in benefit expense.

SUMMARY OF FINANCIAL RESULTS

Disclosure Results Summary

The summary of Fiscal 2013 benefit expense, the defined benefit liability and the DBO as at December 31, 2013, under IAS 19 rev. 2011 are as follows (in $ 000s):

	Fiscal 2013 Net Periodic Benefit Costs	Defined Benefit Asset/(Liability) at December 31, 2013	DBO at December 31, 2013
Electric System Limited	$ 15,028	$ (229,962)	$ 229,962
Toronto Hydro Corporation	408	(2,193)	2,193
Energy Service Incorporated	270	(2,815)	2,815
LDC Unregulated	96	(1,041)	1,041
Consolidated	15,802	(236,011)	236,011

- Actual benefit payments for 2013 of $10,936,000 are based on information provided by the Company on January 9, 2013. We have projected 2014 and 2015 benefit payments based on the valuation assumptions.

OTHER COMMENTS

- The Company transitioned to IFRS rev. 2011 from IFRS rev. 2008 for financial reporting beginning in Fiscal 2013. Please refer to our letter dated January 15, 2013 for additional details.
- We understand that the post-employment benefits plans are not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.
- As directed by the Company, the full defined benefit liability has been classified as a non-current liability
- A draft report on Canadian Pensioners Mortality has been published by the Canadian Institute of Actuaries. We understand that the Company will assess the appropriateness of the new mortality tables when the report is released.
- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2012 for the all benefit plans other than the retirement allowance, and since June 30, 2013 for the retirement allowance, that would materially affect the results of our valuations.

* * * * *

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other post-employment benefit plans.

In preparing the results presented in this letter (including attached exhibits), we have relied upon information provided to us regarding plan provisions, actual benefit payments, historical plan costs and plan participants. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The calculations for the 2013, 2014 and 2015 accounting schedules have been made in accordance with Section 19 (IAS 19 rev. 2011) of the International Accounting Standards, with which we are familiar.

The actuarial assumptions, methods (including guidance on attribution methods) and the accounting policies and methods employed in the development of the pension cost have been selected by the Toronto Hydro management as representing their best estimates of future contingent events.

The expense and obligation levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions, accounting rules, legislature, and the government health care programs, or as a result of future experience gains or losses. None of these changes has been anticipated at this time, but will be revealed in future accounting valuations.

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its period financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

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Enclosures

cc: Olga Baliakina, Mitchell Coviensky — Towers Watson

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2013 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2013		
Defined Benefit Asset/(Liability) at Beginning of Period	(244,084)	(2,020)	(2,909)	(1,068)	(250,081)
Reconciliation of Defined Benefit Obligation			2013		
Defined Benefit Obligation at Beginning of Period	244,084	2,020	2,909	1,068	250,081
Employer Service Cost at Beginning of Period	5,355	321	118	49	5,843
Interest Cost	10,383	92	128	47	10,650
Net Actuarial (Gain) or Loss					
Sick Leave Plan	*(710)*	-	*24*	-	*(686)*
Retirement Allowance Plan #1	-	*(5)*	-	-	*(5)*
Other	*(18,384)*	*(157)*	*(304)*	*(91)*	*(18,936)*
Total Net Actuarial (Gain) or Loss	*(19,094)*	*(162)*	*(280)*	*(91)*	*(19,627)*
Benefits Paid Directly by the Employer	(10,766)	(78)	(60)	(32)	(10,936)
Defined Benefit Obligation at Current Period End	229,962	2,193	2,815	1,041	236,011
Change in Plan Assets			2013		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,766	78	60	32	10,936
Benefits Paid	(10,766)	(78)	(60)	(32)	(10,936)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2013		
Employer Service Cost at Beginning of Period	5,355	321	118	49	5,843
Interest Cost	10,383	92	128	47	10,650
Actuarial (Gain)/Loss Recognized in Expense	(710)	(5)	24	-	(691)
Total Benefit Expense/(Income)	15,028	408	270	96	15,802
Reconciliation of Balance Sheet			2013		
Defined Benefit Asset/(Liability) at Prior Period End	(244,084)	(2,020)	(2,909)	(1,068)	(250,081)
Total Benefit (Expense)/Income for Period	(15,028)	(408)	(270)	(96)	(15,802)
Benefits Paid Directly by the Employer	10,766	78	60	32	10,936
Gain/(Loss) Recognized via OCI	18,384	157	304	91	18,936
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Change in Accumulated Other Comprehensive Income			2013		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	-	-	-	-	-
(Gain) or Loss recognized upon transition to IFRS rev. 2011	36,315	637	656	217	37,825
Actuarial (Gain) or Loss Recognized via OCI for Period	(18,384)	(157)	(304)	(91)	(18,936)
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2013		
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2013		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2013					
1% point increase	2,300	11	41	16	2,368
1% point decrease	(2,010)	(11)	(37)	(14)	(2,072)
Effect on accrued benefit obligation at December 31, 2013					
1% point increase	28,986	202	459	157	29,804
1% point decrease	(25,426)	(182)	(403)	(139)	(26,150)
Key Assumptions					
Discount rate at Dec 31/13 (used for Dec 31/13 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/12 (used for 2013 Benefit Costs)	4.25%	4.25%	4.25%	4.25%	4.25%
Assumed medical and dental cost trend rate at December 31, 2013					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	6.0%	6.0%	6.0%	6.0%	6.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	7.5%	7.5%	7.5%	7.5%	7.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,245	90	44	22	8,401

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Post-Employment Benefits Plan - IFRS (rev. 2011) - 2014 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2014		
Defined Benefit Asset/(Liability) at Beginning of Period	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Reconciliation of Defined Benefit Obligation			2014		
Defined Benefit Obligation at Beginning of Period	229,962	2,193	2,815	1,041	236,011
Employer Service Cost at Beginning of Period	4,931	198	109	44	5,282
Interest Cost	10,962	111	138	51	11,262
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,245)	(90)	(44)	(22)	(8,401)
Defined Benefit Obligation at Current Period End	237,610	2,412	3,018	1,114	244,154
Change in Plan Assets			2014		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,245	90	44	22	8,401
Benefits Paid	(8,245)	(90)	(44)	(22)	(8,401)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2014		
Employer Service Cost at Beginning of Period	4,931	198	109	44	5,282
Interest Cost	10,962	111	138	51	11,262
Total Benefit Expense/(Income)	15,893	309	247	95	16,544
Reconciliation of Balance Sheet			2014		
Defined Benefit Asset/(Liability) at Prior Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Total Benefit (Expense)/Income for Period	(15,893)	(309)	(247)	(95)	(16,544)
Benefits Paid Directly by the Employer	8,245	90	44	22	8,401
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Change in Accumulated Other Comprehensive Income			2014		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	17,931	480	352	126	18,889
Actuarial (Gain) or Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2014		
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2014		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Key Assumptions					
Discount rate at Dec 31/14 (used for Dec 31/13 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/13 (used for 2014 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Assumed medical and dental cost trend rate at December 31, 2014					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.5%	5.5%	5.5%	5.5%	5.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	7.0%	7.0%	7.0%	7.0%	7.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,384	96	47	25	8,552

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2015 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2015		
Defined Benefit Asset/(Liability) at Beginning of Period	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Reconciliation of Defined Benefit Obligation			2015		
Defined Benefit Obligation at Beginning of Period	237,610	2,412	3,018	1,114	244,154
Employer Service Cost at Beginning of Period	5,128	206	113	46	5,493
Interest Cost	11,331	122	148	55	11,656
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,384)	(96)	(47)	(25)	(8,552)
Defined Benefit Obligation at Current Period End	245,685	2,644	3,232	1,190	252,751
Change in Plan Assets			2015		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,384	96	47	25	8,552
Benefits Paid	(8,384)	(96)	(47)	(25)	(8,552)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2015		
Employer Service Cost at Beginning of Period	5,128	206	113	46	5,493
Interest Cost	11,331	122	148	55	11,656
Total Benefit Expense/(Income)	16,459	328	261	101	17,149
Reconciliation of Balance Sheet			2015		
Defined Benefit Asset/(Liability) at Prior Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Total Benefit (Expense)/Income for Period	(16,459)	(328)	(261)	(101)	(17,149)
Benefits Paid Directly by the Employer	8,384	96	47	25	8,552
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Change in Accumulated Other Comprehensive Income			2015		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	17,931	480	352	126	18,889
Actuarial (Gain) or Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2015		
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2015		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Key Assumptions					
Discount rate at Dec 31/15 (used for Dec 31/15 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/14 (used for 2015 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Assumed medical and dental cost trend rate at December 31, 2015					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.0%	5.0%	5.0%	5.0%	5.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	6.5%	6.5%	6.5%	6.5%	6.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,990	99	53	28	9,170

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 72:

Reference(s): **Exhibit 4A, Tab 4, Schedule 7, Towers Watson actuarial report**

The above reference provides calculations in accordance with US GAAP. THESL has applied for rates under IFRS.

Please provide an analysis that compares the 2014 and 2015 projections under US GAAP with IFRS. In the event, there are any differences arising from this analysis, please state whether or not THESL would consider it necessary to update its application to reflect them. If not, please explain why not.

RESPONSE:

OPEB projections for 2014 are provided under US GAAP and those for 2015 are provided under IFRS, consistent with Toronto Hydro's transition to IFRS on January 1, 2015. Please refer to Appendix A to this response for a copy of the IFRS actuarial report as at December 31, 2013. This report includes IFRS projections for 2015 that were included in the Application.

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January 16, 2014

Mr. Daniel Paquin
Toronto Hydro Corporation
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Dan:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2013 YEAR-END DISCLOSURES AND ESTIMATED 2014 AND 2015 BENEFIT EXPENSE UNDER INTERNATIONAL ACCOUNTING STANDARDS

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on total and permanent long-term disability;
- Dental benefits for retirees and members on total and permanent long-term disability;
- Life insurance benefits for retirees;
- Vested and non-vested accumulating sick leave benefits;
- OMERS top up pension; and
- Executive retirement allowances.

This letter and appendices have been prepared for the Company, for the following purposes:

- Determining the final calculation of the 2013 benefit expense under International Financial Reporting Standards (IFRS) in accordance with International Accounting Standards Section 19 revised in 2011;
- Providing the required information for year-end disclosure purposes as of December 31, 2013 under IAS 19 rev. 2011; and
- Determining an estimate of 2014 and 2015 benefit expense under IAS 19 rev. 2011.

The information contained in this letter and appendices is presented in thousands of Canadian dollars, and is in respect of the benefits mentioned above only.

The 2013 benefit expense was determine based on the 2013 benefit expense provided in our letter dated January 15, 2013, with updates for immediate recognition of (gains)/losses related to the retirement allowance and the accumulating sick leave benefits plans. The 2013 year-end disclosure obligations and extrapolations for 2014 and 2015 are based on the results of the January 1, 2012 actuarial valuation.

In 2013, the Company chose to include an obligation in respect of two executive retirement allowances (one of which is considered an incentive plan under IFRS, and the other considered a post-employment benefit under IFRS) granted to one key employee. As directed by the company, the impact of this change was recognized as part of the service cost in expense as at June 30, 2013 in the financial accounting for the Plans under IFRS for the Toronto Hydro Corporation division. Please refer to our email dated July 18, 2013 for additional information.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2012 actuarial valuation report prepared by Towers Watson for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- The measurement date used for Fiscal 2013 year-end financial reporting is December 31, 2013.
- The 2013 benefit expense is based on a discount rate of 4.25% per annum and the defined benefit obligation ("DBO") at December 31, 2013 is based on a discount rate of 4.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2012 and December 31, 2013 respectively.
- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2013 net periodic benefit cost and the December 31, 2013 obligation are consistent with those used for the 2012 disclosures.
- The obligation as of December 31, 2013 and the 2014 and 2015 expense estimates are based on extrapolations from the January 1, 2012 valuation results for the medical, dental, life insurance, accumulating sick leave and OMERS benefits plans, and the June 30, 2013 valuation results for the retirement allowance benefit plans, assuming that there are no experience gains or losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

ACCOUNTING METHODS

- The information presented assumes that the transition date (between IAS 19 rev. 2008 and IAS 19 rev. 2011) is January 1, 2013.
- Under IAS 19 rev. 2011, we understand that Toronto Hydro has determined that both the non-vested accumulating sick leave benefits plan and the vested accumulating sick leave benefits plan should be included for post-employment benefits reporting. As such, these benefits are included in the financial information under IAS 19 rev. 2011 presented in this letter.
- As directed by the Company, as of January 1, 2013, upon transition from IAS 19 rev. 2008 to IAS 19 rev. 2011, all unrecognized gains and losses were fully recognized in other comprehensive income. As such there were no further unrecognized actuarial gains and losses reflected in the defined benefit liability at January 1, 2013 under IAS 19 rev. 2011.
- On an ongoing basis, actuarial gains and losses for all benefit plans other than the accumulating sick leave benefits plans and the one executive retirement allowance considered to be an incentive plan will be immediately recognized in other comprehensive income. Actuarial gains and losses for the accumulating sick leave benefits plans and the one executive retirement allowance considered to be an incentive plan will be recognized immediately in expense.
- On an ongoing basis, the impact of plan changes will be immediately recognized in benefit expense.

SUMMARY OF FINANCIAL RESULTS

Disclosure Results Summary

The summary of Fiscal 2013 benefit expense, the defined benefit liability and the DBO as at December 31, 2013, under IAS 19 rev. 2011 are as follows (in $ 000s):

	Fiscal 2013 Net Periodic Benefit Costs	*Defined Benefit Asset/(Liability) at December 31, 2013*	*DBO at December 31, 2013*
Electric System Limited	$ 15,028	$ (229,962)	$ 229,962
Toronto Hydro Corporation	408	(2,193)	2,193
Energy Service Incorporated	270	(2,815)	2,815
LDC Unregulated	96	(1,041)	1,041
Consolidated	15,802	(236,011)	236,011

- Actual benefit payments for 2013 of $10,936,000 are based on information provided by the Company on January 9, 2013. We have projected 2014 and 2015 benefit payments based on the valuation assumptions.

OTHER COMMENTS

- The Company transitioned to IFRS rev. 2011 from IFRS rev. 2008 for financial reporting beginning in Fiscal 2013. Please refer to our letter dated January 15, 2013 for additional details.
- We understand that the post-employment benefits plans are not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.
- As directed by the Company, the full defined benefit liability has been classified as a non-current liability
- A draft report on Canadian Pensioners Mortality has been published by the Canadian Institute of Actuaries. We understand that the Company will assess the appropriateness of the new mortality tables when the report is released.
- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2012 for the all benefit plans other than the retirement allowance, and since June 30, 2013 for the retirement allowance, that would materially affect the results of our valuations.

* * * * *

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other post-employment benefit plans.

In preparing the results presented in this letter (including attached exhibits), we have relied upon information provided to us regarding plan provisions, actual benefit payments, historical plan costs and plan participants. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The calculations for the 2013, 2014 and 2015 accounting schedules have been made in accordance with Section 19 (IAS 19 rev. 2011) of the International Accounting Standards, with which we are familiar.

The actuarial assumptions, methods (including guidance on attribution methods) and the accounting policies and methods employed in the development of the pension cost have been selected by the Toronto Hydro management as representing their best estimates of future contingent events.

The expense and obligation levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions, accounting rules, legislature, and the government health care programs, or as a result of future experience gains or losses. None of these changes has been anticipated at this time, but will be revealed in future accounting valuations.

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its period financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

Harindra Sebastian, FCIA, FSA
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Enclosures

cc: Olga Baliakina, Mitchell Coviensky — Towers Watson

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2013 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2013		
Defined Benefit Asset/(Liability) at Beginning of Period	(244,084)	(2,020)	(2,909)	(1,068)	(250,081)
Reconciliation of Defined Benefit Obligation			2013		
Defined Benefit Obligation at Beginning of Period	244,084	2,020	2,909	1,068	250,081
Employer Service Cost at Beginning of Period	5,355	321	118	49	5,843
Interest Cost	10,383	92	128	47	10,650
Net Actuarial (Gain) or Loss					
Sick Leave Plan	*(710)*	-	*24*	-	*(686)*
Retirement Allowance Plan #1	-	*(5)*	-	-	*(5)*
Other	*(18,384)*	*(157)*	*(304)*	*(91)*	*(18,936)*
Total Net Actuarial (Gain) or Loss	*(19,094)*	*(162)*	*(280)*	*(91)*	*(19,627)*
Benefits Paid Directly by the Employer	(10,766)	(78)	(60)	(32)	(10,936)
Defined Benefit Obligation at Current Period End	229,962	2,193	2,815	1,041	236,011
Change in Plan Assets			2013		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,766	78	60	32	10,936
Benefits Paid	(10,766)	(78)	(60)	(32)	(10,936)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2013		
Employer Service Cost at Beginning of Period	5,355	321	118	49	5,843
Interest Cost	10,383	92	128	47	10,650
Actuarial (Gain)/Loss Recognized in Expense	(710)	(5)	24	-	(691)
Total Benefit Expense/(Income)	15,028	408	270	96	15,802
Reconciliation of Balance Sheet			2013		
Defined Benefit Asset/(Liability) at Prior Period End	(244,084)	(2,020)	(2,909)	(1,068)	(250,081)
Total Benefit (Expense)/Income for Period	(15,028)	(408)	(270)	(96)	(15,802)
Benefits Paid Directly by the Employer	10,766	78	60	32	10,936
Gain/(Loss) Recognized via OCI	18,384	157	304	91	18,936
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Change in Accumulated Other Comprehensive Income			2013		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	-	-	-	-	-
(Gain) or Loss recognized upon transition to IFRS rev. 2011	36,315	637	656	217	37,825
Actuarial (Gain) or Loss Recognized via OCI for Period	(18,384)	(157)	(304)	(91)	(18,936)
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2013		
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2013		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2013					
1% point increase	2,300	11	41	16	2,368
1% point decrease	(2,010)	(11)	(37)	(14)	(2,072)
Effect on accrued benefit obligation at December 31, 2013					
1% point increase	28,986	202	459	157	29,804
1% point decrease	(25,426)	(182)	(403)	(139)	(26,150)
Key Assumptions					
Discount rate at Dec 31/13 (used for Dec 31/13 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/12 (used for 2013 Benefit Costs)	4.25%	4.25%	4.25%	4.25%	4.25%
Assumed medical and dental cost trend rate at December 31, 2013					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	6.0%	6.0%	6.0%	6.0%	6.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	7.5%	7.5%	7.5%	7.5%	7.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,245	90	44	22	8,401

TOWERS WATSON

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2014 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2014		
Defined Benefit Asset/(Liability) at Beginning of Period	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Reconciliation of Defined Benefit Obligation			2014		
Defined Benefit Obligation at Beginning of Period	229,962	2,193	2,815	1,041	236,011
Employer Service Cost at Beginning of Period	4,931	198	109	44	5,282
Interest Cost	10,962	111	138	51	11,262
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,245)	(90)	(44)	(22)	(8,401)
Defined Benefit Obligation at Current Period End	237,610	2,412	3,018	1,114	244,154
Change in Plan Assets			2014		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,245	90	44	22	8,401
Benefits Paid	(8,245)	(90)	(44)	(22)	(8,401)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2014		
Employer Service Cost at Beginning of Period	4,931	198	109	44	5,282
Interest Cost	10,962	111	138	51	11,262
Total Benefit Expense/(Income)	15,893	309	247	95	16,544
Reconciliation of Balance Sheet			2014		
Defined Benefit Asset/(Liability) at Prior Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Total Benefit (Expense)/Income for Period	(15,893)	(309)	(247)	(95)	(16,544)
Benefits Paid Directly by the Employer	8,245	90	44	22	8,401
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Change in Accumulated Other Comprehensive Income			2014		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	17,931	480	352	126	18,889
Actuarial (Gain) or Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2014		
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2014		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Key Assumptions					
Discount rate at Dec 31/14 (used for Dec 31/13 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/13 (used for 2014 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Assumed medical and dental cost trend rate at December 31, 2014					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.5%	5.5%	5.5%	5.5%	5.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	7.0%	7.0%	7.0%	7.0%	7.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,384	96	47	25	8,552

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2015 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2015		
Defined Benefit Asset/(Liability) at Beginning of Period	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Reconciliation of Defined Benefit Obligation			2015		
Defined Benefit Obligation at Beginning of Period	237,610	2,412	3,018	1,114	244,154
Employer Service Cost at Beginning of Period	5,128	206	113	46	5,493
Interest Cost	11,331	122	148	55	11,656
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,384)	(96)	(47)	(25)	(8,552)
Defined Benefit Obligation at Current Period End	245,685	2,644	3,232	1,190	252,751
Change in Plan Assets			2015		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,384	96	47	25	8,552
Benefits Paid	(8,384)	(96)	(47)	(25)	(8,552)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2015		
Employer Service Cost at Beginning of Period	5,128	206	113	46	5,493
Interest Cost	11,331	122	148	55	11,656
Total Benefit Expense/(Income)	16,459	328	261	101	17,149
Reconciliation of Balance Sheet			2015		
Defined Benefit Asset/(Liability) at Prior Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Total Benefit (Expense)/Income for Period	(16,459)	(328)	(261)	(101)	(17,149)
Benefits Paid Directly by the Employer	8,384	96	47	25	8,552
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Change in Accumulated Other Comprehensive Income			2015		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	17,931	480	352	126	18,889
Actuarial (Gain) or Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2015		
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2015		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Key Assumptions					
Discount rate at Dec 31/15 (used for Dec 31/15 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/14 (used for 2015 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Assumed medical and dental cost trend rate at December 31, 2015					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.0%	5.0%	5.0%	5.0%	5.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	6.5%	6.5%	6.5%	6.5%	6.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,990	99	53	28	9,170

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UNDERTAKING NO. J2.15:

Reference(s):

To explain why THESL is proposing to include CWIP in Account 1575.

RESPONSE:

The Accounting Procedures Handbook Article 510 (Transitional Issues Relating to the Adoption of IFRS) page 13 states:

> Although use of the rate-regulated deemed cost exemption will not result in any adjustment to the net carrying amount of PP&E and intangible assets at the transition date, due to the IFRS accounting requirements for certain PP&E and intangible asset related areas (e.g., capitalized indirect costs, useful lives, interest capitalization, customer contributions), the IFRS carrying amount of items of PP&E and intangible assets for which the rate-regulated deemed cost exemption was elected will not likely be equal to the previous Canadian GAAP carrying amount of these items as at December 31, 2011. For any difference in carrying amount that exists at the changeover date, a distributor must record a journal entry such that the resulting balance recorded in regulatory accounts contained in the USofA is in compliance with IFRS. The offset to this adjusting entry should be recorded in Account 1575, IFRS-CGAAP Transitional PP&E Amounts. [*Emphasis added*]

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Page 19 further states:

> As noted above, adjustments required at the transition date are generally recognized directly in opening retained earnings. In respect of PP&E, a distributor must use Account 1575, IFRS-CGAAP Transitional PP&E Amounts, to record differences arising as a result of accounting policy changes caused by the transition from previous Canadian GAAP to modified IFRS…

Toronto Hydro's interpretation of the above noted passages is that <u>all</u> adjustments (including capitalized interest) related to PP&E and intangible assets that would have been booked as an adjustment to retained earnings should be recognized in Account 1575. The difference in capitalized interest (i.e., Allowance for Funds Used During Construction or AFUDC) between US GAAP and MIFRS/IFRS would have an impact to retained earnings. Therefore, Toronto Hydro believes CWIP balances between these two standards should be recorded in Account 1575.

Accounting for Transitional Issues

Transitional Issues Relating to the Adoption of IFRS

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Transitional Issues Relating to the Adoption of IFRS

Purpose and Scope

The underlying accounting concepts for this Article are based on CICA Handbook Part I – IFRS, IFRS 1 *First-time Adoption of International Financial Reporting Standards* which sets forth the transitional requirements for the first-time adoption of IFRS. Accordingly, this Article should be read in conjunction with IFRS 1.

The purpose of this Article is to provide additional guidance in regard to the first-time adoption of IFRS where further guidance specific to electricity distributors is required. This guidance is in relation to the one-time transitional accounting adjustments required on January 1, 2012 (for most distributors) on adoption of IFRS and there is no intent to suggest the need for "a second set of books" for regulatory purposes to complete these IFRS 1 adjustments.

The accounting changes in the IFRS transition year (2011 for most distributors) arises from financial reporting requirements, more specifically, the IFRS 1 requirement to present the comparative year in accordance with IFRS. All adopters of IFRS are in effect required to prepare "two sets of accounting books" for the 2011 comparative year (one in previous Canadian GAAP and one in IFRS). The guidance in this Article allows a distributor to, in many respects except for specified regulatory requirements, align its "regulatory accounting books" with its "financial accounting books" at January 1, 2012 on adoption of IFRS.

Through its *Report of the Board, Transition to International Financial Reporting Standards*, and its *Addendum to the Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment*, the Board has required some modifications to IFRS for regulatory purposes. In this Article, the term "MIFRS" is used in the discussion of IFRS requirements for which the Board has established regulatory modifications. This would include references to rate applications and regulatory accounting and reporting in general, as these items will contain some elements of MIFRS.

General Summary

IFRS 1 sets out all of the transitional requirements and exemptions available on the first-time adoption of IFRS. Generally, IFRS 1 requires full retrospective application of IFRS in a first-time adopter's first IFRS financial statements, although there are mandatory exceptions and optional exemptions that provide specific relief from this requirement in certain areas.

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Accounting for Transitional Issues

Transitional Issues Relating to the Adoption of IFRS

For financial reporting purposes, a distributor adopting IFRS is required to present one year of comparative information in its first IFRS financial statements. The first day of the comparative year is referred to as the "transition date" (January 1, 2011 for most distributors). The first day of the year in which the distributor has chosen to adopt IFRS for financial reporting purposes is referred to as the "changeover date" (January 1, 2012 for most distributors).

An entity is required to present an opening IFRS balance sheet at the transition date, which is the starting point for accounting in accordance with IFRS.

A first-time adopter typically will generate a series of adjustments in preparing its opening IFRS balance sheet. Any required opening IFRS balance sheet adjustments are generally recognized directly in retained earnings (or, if appropriate, another category of equity) at the transition date.

A first-time adopter must explain in its first IFRS financial statements how the transition from its previous GAAP to IFRS affected its reported financial position, financial performance and cash flows.

All distributors that adopt IFRS must continue to report information to the Board using previous Canadian GAAP until and including the fiscal year prior to the year in which the distributor has chosen to adopt IFRS for financial reporting (fiscal 2012 for most distributors). The reporting under Canadian GAAP continues until fiscal 2011 for items such as the audited financial statements and the USoA trial balance. Effective on the year in which the distributor has chosen to adopt IFRS for financial reporting, a distributor is required to report information to the Board using MIFRS for regulatory accounting values. Those few distributors that have not adopted IFRS for financial reporting must report information to the Board using the form of generally accepted accounting principles applicable to them as regulated entities.

The vast majority of distributors will adopt IFRS in fiscal 2012. For financial reporting purposes, such distributors will be required to present financial information for fiscal 2011 in accordance with IFRS as comparative information in the fiscal 2012 financial statements. As a result, fiscal 2011, which would have already been reported under previous Canadian GAAP, will be restated in accordance with IFRS starting on January 1, 2011 (the transition date).

For regulatory accounting and reporting purposes, a distributor adopting IFRS in fiscal 2012 must begin using MIFRS as of January 1, 2012 (the changeover date). At this date, the distributor is required to compare the balances of the regulatory accounts contained in the USoA as determined under previous Canadian GAAP at December 31, 2011 to the corresponding balances at December 31, 2011 determined in accordance with MIFRS. For any account balances with different carrying amounts, the distributor must record journal entries such that the resulting account balances are in compliance with MIFRS.

Therefore, while a distributor adopting IFRS in fiscal 2012 will recognize any adjustments arising from the transition to IFRS on January 1, 2011 for financial reporting purposes, adjustments arising from the transition to IFRS will not be recognized for regulatory accounting and reporting purposes until January 1, 2012. The adjusting entries recognized on that date will reflect any differences arising on the transition date as well as differences arising during the 2011 fiscal year.

As noted above, adjustments required at the transition date are generally recognized directly in opening retained earnings. Correspondingly, any adjustments required at the changeover date should also generally be recognized in retained earnings. In respect of PP&E, a distributor must use deferral Account 1575, IFRS-CGAAP Transitional PP&E Amounts, to record differences arising as a result of accounting policy changes caused by the transition from previous Canadian GAAP to MIFRS. A generic deferral account is not available for other IFRS related impacts occurring at the transition date. The option remains for distributors to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

For purposes of Reporting and Record-keeping Requirements, a distributor must provide certain reconciliations between financial reporting under IFRS and regulatory accounting information.

Definitions and References

Definitions and accounting treatment of the following are provided in IFRS 1 and are listed below for ease of reference:

CICA Handbook Part I – IFRS 1, First-Time Adoption of International Financial Reporting Standards	Paragraph References
Opening IFRS balance sheet	Paragraph 6
Accounting policies	Paragraphs 7 – 12
Exceptions to the retrospective application of other IFRS	Paragraphs 13 – 17
Exemptions from other IFRS	Paragraph 18
Comparative information	Paragraphs 21 – 22
Explanation of transition to IFRS	Paragraphs 23 – 33
Use of deemed cost for operations subject to rate regulation	Paragraph 31B

The guidance provided in relation to the issues most relevant to a typical electricity distributor is summarized below.

Accounting Issues

First-time Adoption of IFRS and Application of IFRS 1

General Approach

An entity applying IFRS for the first time (first-time adopter) must apply IFRS 1 in its first IFRS financial statements and each interim financial report, if any, that it presents in accordance with IAS 34 *Interim Financial Reporting* for part of the period covered by its first IFRS financial statements (paragraph 2).

A first-time adopter's transition date is the beginning of the earliest period for which the entity presents full comparative information under IFRS in its first IFRS financial statements (Appendix A of IFRS 1). An IFRS balance sheet must be prepared as at the transition date (opening balance sheet); this is the starting point for its accounting in accordance with IFRS (paragraph 6).

IFRS 1 generally requires full retrospective application of IFRS in a first-time adopter's first IFRS financial statements, although there are mandatory exceptions and optional exemptions that provide specific relief from this requirement in certain areas.

Preparation of the opening balance sheet is the starting point for the preparation of a first-time adopter's first IFRS financial statements. The methodology for applying the general recognition and measurement requirements of IFRS 1 in the opening balance sheet is prescribed in paragraphs 1 through 12 and can be summarized into the following steps:

1) select IFRS accounting policies;
2) recognize and derecognize assets and liabilities in accordance with IFRS;
3) reclassify assets, liabilities and components of equity as necessary; and
4) measure all recognized assets and liabilities in accordance with IFRS.

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Each of these steps is discussed below:

Select IFRS accounting policies

In preparing its first IFRS financial statements, a first-time adopter must select accounting policies based on IFRS that are effective as at the reporting date for the first annual IFRS financial statements (paragraph 7). A first-time adopter has a choice in selecting the IFRS accounting policies that it will use on an on-going basis; the constraints on changing accounting policies in accordance with IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors* do not apply (paragraph 27).

The transitional requirements in other IFRS applicable to existing users of IFRS do not apply to first-time adopters unless specifically referred to in IFRS 1 (paragraph 9).

Recognize and derecognize assets and liabilities in accordance with IFRS

In accordance with paragraph 10, those assets and liabilities that should be recognized under IFRS but were not recognized under previous GAAP are recognized in the opening balance sheet and those assets and liabilities that do not qualify for recognition under IFRS but were recognized under previous GAAP are derecognized.

Reclassify assets, liabilities and components of equity as necessary

Paragraph 10 also requires a first-time adopter to reclassify items that it recognized under previous GAAP as one type of asset, liability or component of equity, but which is a different type of asset, liability or component of equity under IFRS.

Measure all recognized assets and liabilities in accordance with IFRS

The last step requires the application of the relevant IFRS measurement criteria effective as at the reporting date for all assets and liabilities recognized in the opening balance sheet (paragraph 10).

Paragraph 11 indicates that the resulting adjustments arising from the application of the general recognition and measurement requirements of IFRS 1 are generally recognized directly in retained earnings (or, if appropriate, another category of equity) at the transition date.

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Mandatory Exceptions to Retrospective Application

Although retrospective application of IFRS is the general approach to be followed by a first-time adopter, IFRS 1 explicitly prohibits retrospective application in respect of certain aspects of the following:

1) accounting estimates;
2) derecognition of financial assets and financial liabilities;
3) hedge accounting;
4) non-controlling interests;
5) classification and measurement of financial assets; and
6) embedded derivatives

Each of these exceptions is discussed below:

Accounting estimates

An entity's estimates in accordance with IFRS at the transition date shall be consistent with estimates made for the same date in accordance with previous GAAP (after adjustments to reflect any difference in accounting policies), unless there is objective evidence that those estimates were in error (paragraph 14).

An entity may need to make estimates in accordance with IFRS at the transition date that were not required at that date under previous GAAP. To achieve consistency with IAS 10 *Events after the Reporting Period*, those estimates in accordance with IFRS shall reflect conditions that existed at the transition date. In particular, estimates at the transition date of market prices, interest rates or foreign exchange rates shall reflect market conditions at that date (paragraph 16).

Estimates made at and prior to the transition date under previous GAAP should not be changed (other than to comply with accounting policies under IFRS for those estimates) unless there is objective evidence that those estimates were in error.

Derecognition of financial assets and financial liabilities

Paragraph B2 requires a first-time adopter to apply the derecognition requirements in IFRS 9 prospectively for transactions occurring on or after the transition date. For example, if a first-time adopter derecognized non-derivative financial assets or non-derivative financial liabilities in accordance with its previous GAAP as a result of a transaction that occurred before the transition date, it shall not recognize those assets and liabilities in accordance with IFRS (unless they qualify for recognition as a result of a later transaction or event).

Despite the above, paragraph B3 permits an entity to apply the derecognition requirements in IFRS 9 retrospectively from a date of the entity's choosing, provided that the information needed to apply IFRS 9 to financial assets and financial liabilities derecognized as a result of past transactions was obtained at the time of initially accounting for those transactions.

Hedge accounting

To prevent a first-time adopter from using hindsight to achieve a specific hedging result, paragraph B6 prohibits a first-time adopter from retrospectively designating derivatives and other qualifying instruments as hedges. A first-time adopter is required to apply hedge accounting prospectively from the transition date if the criteria for hedge accounting in IFRS are met.

Non-controlling interests

In accordance with paragraph B7, first-time adopters are required to apply the following requirements of IFRS 10 prospectively from the transition date:

a) the requirement in paragraph B94 that total comprehensive income is attributed to the owners of the parent and to the non-controlling interests even if this results in the non-controlling interests having a deficit balance;
b) the requirements in paragraphs 23 and B93 for accounting for changes in the parent's ownership interest in a subsidiary that do not result in a loss of control; and
c) the requirements in paragraphs B97–B99 for accounting for a loss of control over a subsidiary, and the related requirements of paragraph 8A of IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*.

Notwithstanding the above, first-time adopters electing to apply IFRS 3 retrospectively to past business combinations must also apply IFRS 10 in accordance with paragraph C1 of IFRS 1.

The consequential amendments to IFRS 1 introduced by IFRS 9 results in two additional mandatory exceptions. These mandatory exceptions are only applicable to entities that will apply IFRS 9 in their first IFRS financial statements.

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Classification and measurement of financial assets

A first-time adopter must assess whether a financial asset meets the criteria for amortized cost classification based on the facts and circumstances that exist at the transition date (paragraph B8).

Embedded derivatives

A first-time adopter must assess whether an embedded derivative is required to be separated from the host contract and accounted for as a derivative on the basis of the conditions that existed at the later of the date it first became a party to the contract and the date a reassessment is required by paragraph B4.3.11 of IFRS 9.

Optional Exemptions from Retrospective Application

Appendices C through E of IFRS 1 provide first-time adopters certain optional exemptions from retrospective application of some aspects of other IFRS standards and interpretations. A first-time adopter may elect to use one or more of the optional exemptions provided. Some of the optional exemptions apply to classes of items or transactions, whereas others may be elected on an item-by-item basis. Paragraph 18 clarifies that the optional exemptions are specific and cannot be applied to other items by analogy.

The optional exemptions most likely relevant to an electricity distributor are as follows:

Rate-regulated deemed cost

The exemption permits an entity which holds items of PP&E or intangible assets that are used, or were previously used, in operations subject to rate-regulation to elect to use the previous GAAP carrying amount of such items on the transition date as deemed cost.

Fair value deemed cost

The exemption permits an entity to use the fair value of an item of PP&E at the transition date as the item's deemed cost at that date.

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Decommissioning liabilities included in the cost of PP&E

The exemption provides a simplified method to re-measure an entity's decommissioning provisions on the transition date.

Employee benefits

This exemption permits an entity to recognize all cumulative actuarial gains and losses in opening retained earnings on the transition date independent of the previous accounting policy under previous GAAP.

A second optional exemption is available in respect of the employee benefit related comparative disclosures required under IFRS.

Transfer of assets from customers

This exemption permits an entity to apply IFRIC 18 prospectively to transfers of assets from customers received on or after the transition date or, if designated, an earlier date.

Leases

IFRIC 4 requires an entity to assess whether an arrangement contains a lease at its inception. IFRS 1 provides an optional exemption that permits a first-time adopter to assess arrangements existing at the transition date based on facts and circumstances at that date.

A second optional exemption related to leases is available for instances where a first-time adopter made the same determination of whether an arrangement contains a lease under previous GAAP as that required by IFRIC 4 but at a date other than that required by IFRIC 4. In such instances, by electing this second optional exemption, the first-time adopter need not reassess that determination for such arrangements at the transition date.

Designation of previously recognized financial instruments

This exemption permits an entity to designate, at the transition date, any financial asset or liability at fair value through profit or loss provided that doing so eliminates or significantly reduces a measurement or recognition inconsistency (sometimes referred to as 'an accounting mismatch') that would otherwise arise from measuring assets or liabilities or recognizing the gains and losses on them on different bases. The exemption is also available when a group of financial assets, financial liabilities or both is managed and its performance is evaluated on a fair value basis, in accordance with a documented risk management or investment strategy.

Transitional Adjustments

A first-time adopter typically will generate a series of adjustments in preparing its opening balance sheet.

Paragraph 23 requires a first-time adopter to explain in its first IFRS financial statements how the transition from its previous GAAP to IFRS affected its reported financial position, financial performance and cash flows. To facilitate the explanation, several reconciliations are required to be included in a first-time adopter's first IFRS financial statements.

Paragraph 25 clarifies that the reconciliations must show the material adjustments made to amounts reported under its previous GAAP in order to determine corresponding amounts under IFRS. A detailed narrative explaining each of the adjustments is required to accompany the reconciliations.

Regulatory Considerations

All electricity distributors that are required to adopt IFRS by accounting standard setting bodies must report information to the Board using MIFRS for regulatory accounting values beginning with the year in which the distributor has chosen to adopt IFRS for financial reporting (fiscal 2012 for most distributors). Those few distributors not required to adopt IFRS for financial reporting must report information to the Board using the form of generally accepted accounting principles applicable to them as regulated entities.

All distributors are required to continue to report information to the Board using previous Canadian GAAP until and including the fiscal year prior to the year in which the distributor has chosen to adopt IFRS for financial reporting.

As noted in Article 100, the Board does not prescribe how the regulatory accounts contained in the USoA are to be rolled up for general purpose financial reporting. Matters related to general purpose financial statements are left to the discretion of the distributor to determine in order to meet the needs of its financial statement users. The discussion in the subsections that follow describes the adjustments necessary to transition the balances in the regulatory accounts contained in the USoA from previous Canadian GAAP to modified IFRS.

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Accounting for Transitional Issues

Transitional Issues Relating to the Adoption of IFRS

Transitional Adjustments

The vast majority of distributors will adopt IFRS in fiscal 2012. The remainder of this Article contemplates such a scenario. To the extent a distributor adopts IFRS subsequent to fiscal 2012, that distributor should inquire of the Board whether the following guidance should be applied by analogy.

For financial reporting purposes, distributors will be required to present financial information for fiscal 2011 in accordance with IFRS as comparative information in the fiscal 2012 financial statements. As a result, fiscal 2011, which would have already been reported under previous Canadian GAAP, will be restated in accordance with IFRS starting on January 1, 2011 (the transition date).

For regulatory accounting and reporting purposes, a distributor adopting IFRS in fiscal 2012 must begin using MIFRS as of January 1, 2012 (the changeover date). At this date, the distributor is required to compare the balances of the regulatory accounts contained in the USoA as determined under previous Canadian GAAP at December 31, 2011 to the corresponding balances at December 31, 2011 determined in accordance with MIFRS. For any account balances with different carrying amounts, the distributor must record journal entries such that the resulting account balances are in compliance with MIFRS.

Therefore, while a distributor adopting IFRS in fiscal 2012 will recognize any adjustments arising from the transition to IFRS on January 1, 2011 for financial reporting purposes, adjustments arising from the transition to IFRS will not be recognized for regulatory accounting and reporting purposes until January 1, 2012. The adjusting entries recognized on that date will reflect any differences arising on the transition date as well as differences arising during the 2011 fiscal year.

As noted above, adjustments required at the transition date are generally recognized directly in opening retained earnings for accounting purposes. Correspondingly, any adjustments required at the changeover date should also generally be recognized in retaining earnings except in the case of PP&E or intangible assets differences which are recorded in Account 1575, IFRS-CGAAP Transitional PP&E Amounts. Whether or not the impact of such adjustment should be recovered from or refunded to ratepayers is a separate ratemaking consideration for which the Board may or may not provide specific guidance.

The following are areas where it is considered likely that a distributor may have an adjustment to recognize at the changeover date. Not all of these areas may be applicable to all distributors. Furthermore, there may be additional areas that give rise to required adjustments that are not described in this Article. In such situations, a distributor should recognize the required changeover date adjustment by analogizing to the guidance provided in this Article.

For purposes of this sub-section of the Article, the offset to all adjusting entries required at the changeover date is recognized in retained earnings. The sub-section entitled Deferral Accounts discusses the extent to which adjustments to retained earnings can be reversed and recognized through a deferral account to be recovered or refunded to ratepayers.

Property, plant and equipment and intangible assets

At the transition date (January 1, 2011 for most distributors) it is likely that most distributors will elect to utilize the rate-regulated deemed cost exemption for qualifying items of PP&E and intangible assets. As a result, on January 1, 2011, the IFRS carrying amount of the items for which the rate-regulated deemed cost exemption was elected will be equal to the previous Canadian GAAP carrying amount of these items as at December 31, 2010.

When the rate-regulated deemed cost exemption is used to establish the cost of an item of PP&E, the deemed cost becomes the new IFRS cost basis at that date; the accumulated depreciation recognized under previous Canadian GAAP is set to nil. An adjusting entry is required at the changeover date to reflect the fact that the accumulated depreciation was set to nil under MIFRS at the transition date.

The Board requires regulated net book value to be used as the basis for setting opening rate base values and reporting to the Board at the time of the first report to the Board or rate application for periods subsequent to the adoption of IFRS. To establish continuity of historical cost, the statement of opening value for regulated net book value includes providing gross capital cost and accumulated depreciation, subject to additional breakout of amounts as necessary to support other regulatory accounting requirements.

A distributor adopting IFRS in 2012 will be required to maintain the detail of the gross capital cost and accumulated depreciation of the items included in rate base as reported under previous Canadian GAAP at December 31, 2011 until the distributor's next rebasing. Therefore, while a distributor electing the rate-regulated deemed cost exemption must record an adjusting entry in the USoA at the changeover date to reflect the fact that accumulated depreciation was set to nil under MIFRS at the transition date, the historical previous Canadian GAAP gross amounts must be maintained until the first rebasing under MIFRS.

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The Board does not prescribe the manner in which the historical Canadian GAAP gross amounts must be maintained, but distributors must do so with sufficient detail to support the continuity of the historical cost or rate base. This requirement should not result in the maintenance of two set of books of original entry as this information is not expected to be on a transactional level of detail. Distributors will already have a level of detailed information available to support the external audit of the opening balances as at January 1, 2011, the activity for 2011 and the closing balances as at December 31, 2011 for previous Canadian GAAP. That level of information would be a good starting point for the distributor to judge the level of detail necessary to support the requirements of the gross asset costs. In addition, the Board anticipates that the information to support additions, deletions and the depreciation calculation in previous Canadian GAAP for each year beginning with 2012 can be derived analytically from the underlying acquisition, disposal and depreciation calculations otherwise recorded using IFRS, and provided in the same asset categories, in the accounts as required in the Board's prescribed USoA.

Although use of the rate-regulated deemed cost exemption will not result in any adjustment to the net carrying amount of PP&E and intangible assets at the transition date, due to the IFRS accounting requirements for certain PP&E and intangible asset related areas (e.g., capitalized indirect costs, useful lives, interest capitalization, customer contributions), the IFRS carrying amount of items of PP&E and intangible assets for which the rate-regulated deemed cost exemption was elected will not likely be equal to the previous Canadian GAAP carrying amount of these items as at December 31, 2011. For any difference in carrying amount that exists at the changeover date, a distributor must record a journal entry such that the resulting balance recorded in the regulatory accounts contained in the USoA is in compliance with IFRS. The offset to this adjusting entry should be recorded in Account 1575, IFRS-CGAAP Transitional PP&E Amounts.

Post-employment benefits

Distributors with defined benefit post-employment plans that used the corridor method to recognize actuarial gains and losses under previous Canadian GAAP will have unamortized actuarial gains and losses at the transition date. It is likely that most distributors in such a situation will utilize the available optional exemption and elect to recognize all cumulative actuarial gains and losses in opening retained earnings on the transition date.

Distributors that recognized a transitional obligation upon adoption of CICA Handbook section 3461 *Employee Future Benefits* may still be carrying a portion of that transitional obligation under previous Canadian GAAP at the transition date. Such an obligation does not qualify for recognition under IFRS, and as a result must be recognized in opening retained earnings on the transition date.

The actuarial valuation of a defined benefit post-employment plan obligation under IFRS may differ from the actuarial valuation of the plan that was obtained under previous Canadian GAAP. In such instances, an adjusting entry is required at the transition date to remeasure the obligation to the IFRS compliant carrying amount. The offset to this adjusting entry should be recognized in opening retained earnings.

If a distributor is affected by one or more of the above described differences, the IFRS carrying amount of its defined benefit post-employment plan obligation will not be equal to the previous Canadian GAAP carrying amount of the obligation as at December 31, 2011. For any difference in carrying amount that exists at the changeover date, a distributor must record a journal entry such that the resulting balance recorded in the regulatory accounts contained in the USoA conforms to IFRS. The offset to this adjusting entry should be recognized in opening retained earnings.

Decommissioning obligations

Distributors may have determined that additional decommissioning liabilities (asset retirement obligations) are required under IFRS as compared to previous Canadian GAAP. In such instances, an adjusting entry is required at the transition date to recognize the additional decommissioning liabilities. The offset to this adjusting entry should be pro-rated between opening retained earnings and the underlying item(s) of PP&E in the manner prescribed by IFRS 1.

Decommissioning liabilities are measured initially at management's best estimate of the expenditure expected to be incurred under IFRS whereas such liabilities were measured initially at fair value under previous Canadian GAAP. In addition, the present value of a decommissioning liability was determined under previous Canadian GAAP using a credit-adjusted risk-free discount rate whereas IFRS requires the obligation to be discounted using a rate specific to the liability. As a result of these two measurement differences, an adjusting entry may be required at the transition date to remeasure existing decommissioning liabilities to the IFRS compliant carrying amount. The offset to this adjusting entry should be pro-rated between opening retained earnings and the underlying item(s) of PP&E in the manner prescribed by IFRS 1.

Distributors may have recognized a decommissioning liability under previous Canadian GAAP and then subsequently disposed of the underlying item of PP&E. In certain instances, the distributor may not have derecognized the decommissioning liability at the time the PP&E was disposed and may still be recognizing the liability under previous Canadian GAAP at the transition date. To the extent the distributor is not obligated to perform any further decommissioning activities in respect of the disposed PP&E, the decommissioning liability may not qualify for recognition under IFRS and should therefore be recognized in opening retained earnings on the transition date.

If a distributor is impacted by one or more of the above described differences, the IFRS carrying amount of its decommissioning liabilities will not be equal to the previous Canadian GAAP carrying amount of the liabilities as at December 31, 2011. For any difference in carrying amount that exists at the changeover date, a distributor must record a journal entry such that the resulting balance recorded in the regulatory accounts contained in the USoA is in compliance with IFRS. The offset to this adjusting entry should be recognized in opening retained earnings

Customer contributions

At the transition date it is likely that most distributors will elect to use the exemption and apply IFRS to customer contributions received on or after the transition date.

Under previous Canadian GAAP, customer contributions were recognized in a contra asset account such that the item of PP&E to which the contribution related was effectively recognized on a net basis. Subsequent to the changeover date, for regulatory reporting purposes, customer contributions are recognized as deferred revenue and amortized to income over the useful life of the assets to which they relate. The effect of this accounting requirement is that the item of PP&E to which a contribution relates will be recognized on a gross basis.

Although the use of the exemption will not result in any differences arising at the transition date, due to the IFRS accounting requirements for customer contributions, an adjustment will be required at the changeover date to reclassify the unamortized balance of customer contributions received subsequent to the transition date from the contra asset account in which the contributions were recorded for previous Canadian GAAP to deferred revenue.

For ratemaking purposes, the balance of the deferred revenue account will be included as an offset to rate base. Furthermore, distributors should confirm in their first rates application after the IFRS transition that the amortization period of the deferred revenue is being appropriately adjusted on an ongoing basis to reflect any changes in the remaining useful lives of the underlying capital assets to ensure a consistent matching of the revenues and the depreciation expenses.

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Transitional Issues Relating to the Adoption of IFRS

Illustrative Example

The following example illustrates application of a selection of the above concepts and requirements.

Distributor (a rate-regulated electricity distributor) will prepare its first IFRS financial statements for the year ended December 31, 2012 and will therefore have a transition date of January 1, 2011 and a changeover date of January 1, 2012.

The amount of relevant account balances at December 31, 2010 as per Distributor's audited previous Canadian GAAP financial statements were as follows:

Account	**Previous Canadian GAAP carrying amount at December 31, 2010**
Property, plant and equipment (all of which is used in rate-regulated activities)	1,000
Unamortized Customer contributions recognized as an offset to property, plant and equipment	(100)
Accumulated depreciation	(200)
Net property, plant and equipment	700
Employee future benefit liability	500
Unamortized actuarial losses	50
Unamortized transitional obligation	10

Distributor records its employee future benefits expense in Accounts 5645 and 5646 in accordance with Article 470.

At the transition date, Distributor elects to utilize the following optional exemptions:

- rate-regulated deemed cost
- recognition of unamortized actuarial losses
- prospective treatment for customer contributions

Additionally, the amount of relevant balances during the year ended and as at December 31, 2011 as per Distributor's audited previous Canadian GAAP financial statements and MIFRS calculations were as follows:

Transitional Issues Relating to the Adoption of IFRS

Account	CGAAP	MIFRS
Gross PP&E at Jan 1, 2011[1]	1,000	700
Additions to PP&E during 2011[2]	260	240
Gross PP&E at Dec 31, 2011	**1,260**	**940**
Accumulated depreciation at Jan 1, 2011[1]	(200)	Nil
Depreciation expense during 2011[3]	(13)	(10)
Accumulated depreciation at Dec 31, 2011	**(213)**	**(10)**
Unamortized customer contribution offset at Jan 1, 2011[4]	(100)	Nil
Customer contributions received during 2011[4]	(40)	Nil
Amortization of previous customer contributions during 2011[5]	5	
Amortization of contributions received during 2011[5]	2	Nil
Customer contribution offset at Dec 31, 2011[4,5]	**(133)**	**Nil**
Net PP&E at Dec 31, 2011	**914**	**930**
Deferred revenue at Jan 1, 2011[4, 5]	Nil	Nil
Customer contributions received during 2011[4]	Nil	40
Amortization of contributions received during 2011[5]	Nil	(1)
Deferred revenue at Dec 31, 2011[4, 5]	Nil	39
Employee future benefit liability at Jan 1, 2011[6]	500	560
Employee future benefit expense during 2011[7]	40	30
Employee future benefit liability at Dec. 31, 2011[8]	530	580

1. When the rate-regulated deemed cost exemption is used, the deemed cost becomes the new IFRS cost base at that date; the accumulated depreciation and unamortized customer contributions recognized under previous Canadian GAAP are set to nil
2. Distributor's capitalization policies under IFRS differ from previous Canadian GAAP policies
3. Previous Canadian GAAP depreciation expense is based on different useful lives than IFRS expense
4. Under previous Canadian GAAP customer contributions are recognized as an offset to PP&E (in USoA Account 1995, Contributions and Grants-Credit). Under IFRS, customer contributions received

subsequent to the transition date are recognized as deferred revenue. Note that customer contributions recognized prior to the transition date are not reclassified to deferred revenue as a result of electing the optional exemptions

5. Under previous Canadian GAAP the amortization of customer contributions in Account 1995 is recognized as an offset to depreciation expense. However, under IFRS the amortization of the deferred revenue is recognized as income (in Account 4245, Government and Other Assistance Directly Credited to Income), which is an offset to depreciation expense.
6. At the transition date the unamortized actuarial losses and transitional obligation are recognized in opening retained earnings, resulting in an increase in the employee future benefit liability
7. Previous Canadian GAAP employee future benefit expense includes the amortization of unamortized actuarial losses and transitional obligation as at transition date. IFRS expense does not include any such amounts since the unamortized amounts at the transition date were recognized in opening retained earnings
8. The previous Canadian GAAP employee future benefit liability is reduced by the unamortized actuarial losses and transitional obligation. The IFRS liability is not reduced by such amounts since the unamortized amounts at the transition date were recognized in opening retained earnings. The 50 difference between the carrying amount of the employee future benefit liability at Dec 31, 2011 is comprised of the 60 difference that existed at January 1, 2011 (described in footnote 6 above) less 10 of amortized actuarial loss during 2011

Based on the above information, the following illustrates the entries to be recorded by Distributor at the changeover date of **January 1, 2012** for purposes of transitioning the USoA account balances from previous Canadian GAAP to MIFRS.

Note that for purposes of this example, Distributor has used Account 1575, IFRS-CGAAP Transitional PP&E Amounts, to record PP&E differences arising as a result of accounting policy changes caused by the transition from previous Canadian GAAP to MIFRS. Absent such a deferral account, these PP&E differences would be recognized directly in retained earnings. Deferral accounts are further discussed in the sub-section that follows.

ACCOUNT	PARTICULARS	DEBIT	CREDIT
1575 1805-1990	IFRS-CGAAP Transitional PP&E Amounts Detail PP&E Accounts (as applicable) *To recognize the cumulative effect of the deemed cost exemption and the application of IFRS accounting policies during 2011 (1,260 – 940)*	320	 320

2105 1575	Accumulated depreciation IFRS-CGAAP Transitional PP&E Amounts *To recognize the cumulative effect of the deemed cost exemption and the application of IFRS accounting policies during 2011 (213-10)*	203	 203
1995 1575 2440	Contributions and Grants - Credit IFRS-CGAAP Transitional PP&E Amounts Deferred Revenue *To recognize the cumulative effect of the deemed cost exemption and the application of IFRS accounting policies for customer contributions during 2011*	133	 94 39
3045 2306	Unappropriated Retained earnings Employee future benefit liability *To recognize the cumulative effect of the actuarial loss exemption, the derecognition of the transitional obligation and the application of IFRS accounting policies for employee future benefits during 2011 (580-530)*	50	 50

<u>Deferral Account</u>

As noted above, adjustments required at the transition date are generally recognized directly in opening retained earnings. In respect of PP&E, a distributor must use Account 1575, IFRS-CGAAP Transitional PP&E Amounts, to record differences arising as a result of accounting policy changes caused by the transition from previous Canadian GAAP to modified IFRS as follows (for purposes of this account, PP&E includes rate base related intangible assets):

A. Distributors shall maintain records using previous Canadian GAAP of the amounts in the PP&E accounts that will be included in rate base, commencing at their last rebasing under previous Canadian GAAP, and continuing until their first rebasing under modified IFRS. The PP&E accounts noted above may also include items of PP&E recorded in PP&E related deferral accounts, if applicable (e.g., Accounts 1555, 1531 and 1534). This will produce a figure for the PP&E accounts that is consistent with their last rebasing. Records should be kept to at a level of detail sufficient to support the analysis and justification of the entries made to the account.

B. Distributors shall also calculate "adjusted rate base" values for the PP&E components of rate base using the accounting system applicable in each year between rebasing under previous Canadian GAAP and the first rebasing under MIFRS. For example, if a distributor rebased using previous Canadian GAAP in 2010, and continued with previous Canadian GAAP in 2011, and then moved to IFRS for financial reporting for 2012 and 2013, it would calculate the PP&E components of rate base using previous Canadian GAAP in 2010 and 2011, and MIFRS in 2011, 2012 and 2013. (2011 must be included in MIFRS because the year before the move to IFRS has to be restated under IFRS.)

C. Distributors shall record in the deferral account the cumulative difference between items 1 and 2 above. The calculations for the balance in this account (which does not accrue carrying charges) provide the Board with the evidence to consider an adjustment to the opening values of the PP&E components of rate base up or down in the first MIFRS rebasing year to match the "adjusted rate base" figure above. For that rebasing year, and every subsequent year, rate base will be calculated on a MIFRS basis.

D. The amount of the cumulative adjustment up or down (unamortized balance of the deferral account) should be recorded as a balance to be recovered from, or refunded to, ratepayers and as an adjustment to opening rate base in the year of rebasing (with rate base otherwise calculated on an MIFRS basis).

E. Distributors shall reflect the deferral account balance as an adjustment to MIFRS calculated rate base going forward, and amortize that adjustment over a period of time approved by the Board. The rate base, upon which the distributor's return on rate base calculation is based in the cost of service application, will therefore include two components: the MIFRS based elements of PP&E, and the unamortized balance in the deferral account. Thus the unamortized balance in the deferral account will attract the same level of return in determining revenue requirement in a cost of service application as other PP&E balances. The return on rate base shall not be recorded in this account. On disposition of the account balance, the return is applied prospectively in rates as an adjustment to the revenue requirement.

The Board will determine the period of time for amortization on a case-by-case basis and will be guided primarily by such considerations as the impact on rates, implications of any other IFRS transition matters and any requirements for rate mitigation.

Amortization of the adjusting amount for the disposition of account balance, up or down, shall be reflected in any applicable rate application as an adjustment to depreciation expense (the refund or recovery of the amount of the adjustment over time) and the return on rate base calculation on the unamortized balance shall be included in applicable revenue requirement calculations in the same way as for any other component of rate base.

Distributors must propose the level and pattern of recovery in rates of the amounts in the account for consideration by the Board in their next cost of service application after adopting IFRS. In general, the account will be cleared at the first rebasing under MIFRS. In individual cases, the Board may decide to clear only a portion of the balance, and await actual results for the clearance of the remainder of the account.

The Board has not approved the creation of a generic account for other IFRS related impacts occurring at the transition date. The option remains for distributors to seek an individual account if they can demonstrate the likelihood of a large cost impact upon transition to IFRS.

Required Reconciliations

For purposes of RRR, a distributor must provide reconciliations between financial reporting under IFRS and regulatory accounting information as follows:

For fiscal years beginning with the year in which the distributor chose to adopt IFRS for financial reporting, reconciliations between IFRS for financial reporting and MIFRS.

Distributors are required to include in their annual RRR filing a reconciliation of reported annual performance. Specifically, the following is required:

- A one-time reconciliation between the 2011 previous Canadian GAAP audited financial statement figures and the 2011 IFRS audited financial statement comparative figures that were reported as part of the 2012 IFRS audited financial statements to be performed and submitted with the RRR annual performance reporting for 2012 (filed in 2013).

- A one-time mapping and reconciliation between the 2011 USoA balances and the 2011 IFRS audited financial statement comparative figures that were reported as part of the 2012 IFRS audited financial statements to be submitted with the RRR annual performance reporting for 2012 (filed in 2013).

- Where an electricity distributor has not rebased under MIFRS, a reconciliation is to be provided each year during an IRM period for Group 1 deferral and variance accounts between amounts recorded under previous Canadian GAAP and MIFRS. A distributor must submit this reconciliation with the RRR annual performance reporting for each year for the period beginning with the year of adoption of IFRS and ending in the year in which it rebases under MIFRS.

- All distributors must provide, when reporting annually in RRR the balance in the deferral account (1575) created to record differences in PP&E arising from the transition from previous Canadian GAAP to MIFRS, a reconciliation each year between reported amounts calculated using previous Canadian GAAP and amounts calculated using MIFRS. This reconciliation is required up to and including the year of first rebasing under MIFRS.

Audit assurance is required for the third reconciliation listed (Group 1 deferral and variance accounts), to be provided by an external auditor to the "review level of assurance" specified in the CICA Handbook. For the other reconciliations listed, no audit assurance is required.

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Accounting for Transitional Issues
Applying Generally Accepted Accounting Principles in a Rate Regulated Environment (Former Article 310)

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UNDERTAKING NO. J2.16:

Reference(s):

To provide accounting handbook standards underlying change in treatment of land lease.

RESPONSE:

Under US GAAP, per Accounting Standards Codification 840-10-25-37 – Leases,

> If land is the sole item of property leased and either the transfer-of-ownership criterion in paragraph 840-10-25-1(a) or the bargain-purchase-option criterion in paragraph 840-10-25-1(b) is met, the lessee shall account for the lease as a capital lease. Otherwise, the lessee shall account for the lease as an operating lease.

In accordance with the above definition, land leases with a 99-year terms are considered operating leases under US GAAP because the lease agreements do not include any terms that would allow Toronto Hydro to obtain ownership at the end of the lease term. As such, land leases were not capitalized as part of fixed assets under US GAAP.

Under IFRS, the land leases are considered a finance lease because the significant risks and rewards of ownership of the land are substantially transferred to Toronto Hydro, as set out in IAS 17 – Leases, paragraph 8:

> A lease is classified as a finance lease if it transfers substantially all the risks and rewards incidental to ownership. A lease is classified as an operating

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> lease if it does not transfer substantially all the risks and rewards incidental to ownership.

The accounting treatment under IFRS is the same treatment under mIFRS based on the Accounting Procedures Handbook, Article 425 – Leases, pages 6 and 8.

At page 6,

> In determining whether the land element is an operating or a finance lease, an important consideration is that land normally has an indefinite economic life. [paragraph 15A]. A lease term for the major part of the economic life of the asset can indicate that a lease is a finance lease, even if title is not transferred. The Basis for Conclusions ("BC") which accompanies, but is not part of, IAS 17 provides additional analysis in determining whether the land element is an operating or a finance lease.
>
> (a) In a 99-year lease of land and buildings, the significant risks and rewards associated with the land during the lease term are transferred to the lessee during the lease term, regardless of whether title will be transferred; and
>
> (b) The present value of the residual value of the property with a lease term of several decades would be negligible and therefore accounting for the land element as a finance lease is consistent with the economic position of the lessee. [BC8B, BC8C]
>
> It follows that a long lease term may indicate that a lease of land is a finance lease. This is not because the lease term will thereby cover the major part of the

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> economic life of the land, but because in a long lease of land the risks and rewards retained by the lessor through its residual interest in the land at the end of the lease are not significant when measured at inception. Conversely, a short term lease of land is unlikely to be a finance lease as the risks and rewards retained by the lessor through its residual interest in the land at the end of the lease are likely to be significant."

At page 8,

> A "finance" lease is essentially similar to a "capital" lease under previous Canadian GAAP. Accordingly, a finance lease will be given ratemaking consideration for inclusion in rate base.

The lease term for the land leases in quest is 99 years. In addition, at the end of the lease term Toronto Hydro may continue to lease the land on a month to month basis, which Toronto Hydro will likely opt to continue. Because of the long lease term and the likely continuance of Toronto Hydro leasing the land after the lease term has ended, the significant risks and rewards of ownership would substantially be transferred to Toronto Hydro. As such, under IFRS/MIFRS, the land leases are considered as finance leases, and are capitalized as part of fixed assets.

Although the difference in accounting treatment of the land lease under US GAAP and IFRS/MIFRS will cause a difference in the PP&E balance, there will be no impact to Account 1575 as a result of the following journal entries:

Dr. PP&E	$7.2 million	
Cr. Account 1575		$7.2 million

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Dr. Account 1575	$7.2 million	
Cr. Prepaid Expense		$7.2 million.