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toronto hydro electric system

February 9, 2011

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited's ("THESL")
2011 Electricity Distribution Rate Application - Accounting Update
OEB File No. EB-2010-0142

On January 26, 2011, counsel to THESL sent a letter to the Board requesting that the Board adjourn the settlement discussions in this proceeding until THESL could file an update ("Accounting Update") to its application. Among other things, the letter stated that THESL would file its Accounting Update on or before February 9, 2011.

The Board issued Procedural Order No. 8 on January 27, 2011, approving the adjournment of the settlement discussions, and Procedural Order No. 9 set out a revised schedule for the proceeding.

As stated in THESL's January 26, 2011 letter, THESL's Accounting Update includes:

1) A summary of the history and reasons that have led up to the need to prepare updated evidence;
2) A table summarizing the material changes to the relief requested in the application;

3) Updates to specific portions of the pre-filed evidence to reflect the change in accounting estimates;
4) Evidence supporting the changes, including a new depreciation study and a costing change summary; and
5) A revised analysis of 2011 rate impacts.

The updated evidence has been compiled and presented in Exhibit Q1, Tab 2, Schedules 1 to 12. The updated evidence shows the impact of the Accounting Update and also includes the increase in charitable donations from $0.1 M to $0.7 M referenced in THESL's letter to the Board dated November 8, 2010.

Yours truly,

[original signed by]

Glen A. Winn
Manager
Regulatory Applications & Compliance

encl.

:GAW/acc

cc: J. Mark Rodger, Counsel for THESL
Intervenors of Record for EB-2010-0142

2011 TEST YEAR: ACCOUNTING UPDATE

SUMMARY

On August 23, 2010, THESL filed with the Board its rate application for 2011 based on the most current information available at that time. As described in Exhibit Q1, Tab 1, Schedule 1, Page 2, at the time the application was being prepared the Accounting Standards Board ("AcSB") had not communicated its decision regarding the exposure draft related to rate-regulated activities and the proposed option to defer adoption of International Financial Reporting Standards ("IFRS") until January 1, 2013. Given uncertainty around the timing, scope and potential adoption of a rate-regulated accounting standard under IFRS, THESL was not able to make a definitive decision with respect to the time of its adoption of IFRS. In addition, the assessment of the impacts to CGAAP had not been completed. As a result THESL decided to file its rate application for 2011 in accordance with its CGAAP accounting practices in use at that time.

Since the 2011 rate application was filed in August 2010, THESL continued to develop its accounting positions and operational processes to be compliant with IFRS. THESL also continued to assess the impact of the accounting policy conclusions on both financial and regulatory reporting and how certain IFRS accounting positions and new information resulting from the IFRS project would be necessary under CGAAP.

As a result of the assessment under CGAAP, THESL determined that certain changes in accounting estimates were required to be applied as additional and more relevant information had been made available through the IFRS project. The changes related to the manner in which THESL records and accounts for its property, plant and equipment ("PP&E"), and are described below in the following section.

In September 2010, subsequent to THESL's August filing, the AcSB issued its decision stating that qualifying entities with rate-regulated activities would be permitted to defer the adoption of IFRS for one year, up to January 1, 2012.

Following the AcSB decision, THESL had discussions with its external auditor, Ernst & Young, LLP, in regard to the impact that the new information would have on its PP&E accounting estimates under CGAAP. THESL's external auditor acknowledged the appropriateness of prospective application of the changes in accounting estimates, as described below.

The following Schedules in Exhibit Q1, Tab 2 provide THESL's update to its August filing, and specifically discuss the material changes to the 2011 revenue requirement arising from the accounting updates applied.

2011 ACCOUNTING UPDATE: CHANGES IN ACCOUNTING ESTIMATES

The subsections below describe the material changes to accounting estimates that THESL is applying prospectively for financial and regulatory reporting purposes, effective January 1, 2011. These required changes in accounting estimates were determined through the work performed by THESL in preparation for its adoption of IFRS.

THESL assessed all of the changes in estimates presented below, and found that they all qualify for prospective application in accordance with CICA Handbook Section 1506, *Accounting Changes*, as well as Article 320, *Application of Accounting Concepts: Accounting Changes*, and/or Article 510, *Interpretation Bulletin: Transitional Issues Relating to Setting Up Accounts Pursuant to Part XI of the Electricity Act, 1998* of the OEB's Accounting Procedures Handbook ("APH").

Depreciation and Amortization Rates

Prior to January 1, 2011, THESL had been depreciating assets in accordance with the guidelines provided in the OEB's 2006 Electricity Distribution Rate Handbook ("EDR HB"). This practice was permitted under CGAAP as the prescribed useful lives represented the "estimated service lives" of assets under the regulatory framework.

In the third quarter of 2009, THESL commissioned a review by Kinectrics Inc. to serve as the basis for assigning useful lives to distribution system assets for the purposes of IFRS reporting. The resulting report (the "Kinectrics report") provided THESL with recommended ranges of useful lives by distribution asset and/or component types, ranging from minimum to maximum useful lives, as well as the typical useful lives experienced by utilities with similar assets. THESL reviewed the recommendations made by Kinectrics and determined the appropriate useful lives for the distribution assets, within the ranges provided in the Kinectrics report (Exhibit Q1, Tab 2, Schedule 7-2).

In April of 2010, the OEB released for comment a similar report prepared by Kinectrics Inc. ("OEB Kinectrics report"). On July 8, 2010, the OEB issued a letter entitled *Depreciation Study for Use by Electricity Distributors, Consultant Final Report* which indicated that the OEB Kinectrics report could be used as a tool for determining useful lives for distribution assets that may be acceptable for regulatory reporting purposes, in the absence of distributor-specific studies. In accordance with the requirements of CGAAP, as new information became available THESL reviewed and prospectively updated the service lives of assets for both financial and regulatory reporting purposes, effective January 1, 2011.

In the fourth quarter of 2009, THESL also conducted a review of the useful lives of its building facilities, including both administrative and station buildings, for the purposes of IFRS reporting. THESL was assisted in this review by Pinchin Environmental Ltd., and the results of this review allowed THESL to reassess useful lives by asset and/or component types with respect to specific facilities. The OEB Kinectrics report also provided useful life ranges related to buildings found in utilities across Ontario. Useful life ranges provided in the OEB Kinectrics report were similar to those determined by THESL facilities management in the buildings review.

Other assets (i.e., rolling stock, meters, equipment, etc.) were assessed internally by THESL, and were found to generally fall either within, or close to, the ranges determined by the OEB Kinectrics report, where provided.

For the majority of THESL's distribution system assets, the useful lives of assets were extended under both CGAAP and IFRS. Extending the useful lives of these assets will result in a significant decrease in depreciation expense under the new accounting estimates. The decrease in depreciation expense also results in a corresponding increase in rate base. The latter rate base change only slightly offsets the significant decrease to revenue requirement resulting from lower depreciation expense.

Exhibit Q1, Tab 2, Schedule 7-1 presents THESL's revised depreciation and amortization rates.

Engineering Capital

The design, construction and operation of the distribution system are based on sound engineering principles and practices. THESL employs engineers and technologists to ensure the distribution plant is designed accordingly and continues to provide efficient and reliable service.

Prior to the required changes in accounting estimates being adopted for the 2011 Accounting Update, the majority of the engineering, design and operational effort and associated costs were deemed to provide benefits beyond the current period and were therefore capitalized through THESL's Engineering Capital allocation. A small portion of the related costs were expensed. The allocation method employed by THESL in respect of Engineering Capital was an overhead allocation charge to projects.

As part of the IFRS project, THESL was required to change its processes with respect to the allocation of Engineering Capital, and breakdown the costs being directly attributed to assets into finer detail. In accordance with CICA HB 3061, *Property, Plant and Equipment* ("CICA HB 3061") the cost of an item of PP&E should include overhead costs that are directly attributable to the construction or acquisition of an asset. Based on the new information arising from the process changes undertaken for the IFRS initiative, THESL determined that the amount to be capitalized in respect of Engineering Capital would be significantly lower compared to the then current estimates used, due to the removal of overhead costs no longer directly attributable to assets.

As of January 1, 2010 THESL personnel involved in the Engineering Capital allocation began to record their daily activities to either capital or overhead/administrative projects using timesheets. Through this process, it was determined that approximately 65 percent of the costs previously allocated to capital through the Engineering Capital allocation represented costs that were directly attributable to assets, while the remainder of the costs represent overhead and/or administrative tasks performed by such personnel that were not directly attributable to the assets.

Given the new available information, THESL is required under CGAAP to prospectively apply the practice of charging Engineering Capital labour directly to capital projects through time sheeting, as opposed to allocating these costs in a general manner.

This required change in practice results in an increase in Operating, Maintenance and Administrative ("OM&A") expenses which is partially offset by a decrease to capital expenditures and rate base. On a net basis, these changes result in an increase in revenue requirement for 2011.

Payroll Burden (Standard Labour Rates)

The burdened payroll cost of employees outside of the Engineering Capital pool is directly attributed to assets through labour costing, utilizing standard labour rates ("SLRs") and time keeping data. While the principles in both IFRS and CGAAP permit the use of SLRs, certain inputs to THESL's SLR calculations will now differ from past practice, resulting in lower capitalization of labour costs as certain overhead and administrative costs are removed from capitalization.

Each year, THESL reviews its assumptions with respect to the utilization rates used in calculating SLRs for employees. In applying the new practices to overhead and administrative costs, THESL determined that time spent on certain tasks (such as training and operational meetings) qualified as overhead or administrative costs which are not directly attributable to assets in accordance with CICA HB 3061. This has the effect of reducing the SLRs across most of THESL's employee classes, which effectively reduces the capitalized costs charged to projects.

Based on THESL's capital program and its labour resource requirements, internal labour costs charged to capital jobs will be significantly lower following this required change in practice. This change will result in a decrease to both capital expenditures and rate base and an increase in OM&A expenses. On a net basis, these changes will result in an increase in revenue requirement for 2011.

Stores Operation (Materials On-Cost)

THESL records a materials handling charge against raw materials issued from its warehouse as a method of allocating the costs of materials management and storage to both capital and maintenance projects. Costs incurred related to this charge include those costs associated with acquiring, handling and storing of materials, as well as burdened labour costs for staff working in stores operation (i.e., warehousing and inventory management).

Some of the costs included in the pool of costs that were capitalized to projects are now considered to be of an administrative or overhead nature, which are not directly attributable to assets in accordance with CICA HB 3061, and consequently will no longer be capitalized under THESL's updated practices.

Based on THESL's capital program and its requirement for materials issued from stores, materials handling costs capitalized to capital jobs will be lower due to the required change in practice. This will result in a decrease to both capital expenditures and rate base and an increase in OM&A expenses. On a net basis, these changes will result in an increase in revenue requirement for 2011.

Rolling Stock Operation (Vehicle Hire Rates)

THESL incurs costs related to the maintenance of automobiles, trucks, equipment and trailers. In addition, costs are incurred with respect to burdened labour costs of staff directly involved in rolling stock maintenance. As a means of allocating such costs to projects, THESL associates a vehicle hire rate ("VHR") with each vehicle included in its fleet. Similar to SLRs above, as each vehicle is utilized the related costs are directly charged to the relevant project whether the project is capital or operating in nature.

In applying the required changes in accounting practice, THESL has determined that certain costs related to rolling stock maintenance charged to capital would qualify as overhead costs, which are not directly attributable to assets in accordance with CICA HB 3061. This has the effect of reducing the VHRs across all of THESL's rolling stock classes and consequently reduces the capital costs charged to projects. This will result in a decrease to both capital expenditures and rate base and an increase in OM&A expenses. On a net basis, these changes will result in an increase in revenue requirement for 2011.

MATERIAL CHANGES TO REVENUE REQUIREMENT

Overall, THESL has determined that its 2011 Service and Base Revenue Requirements will significantly decrease as a result of the required adoption of the changes in estimates presented above in the Accounting Update, mainly driven by a decrease in depreciation expense due to extended fixed asset useful lives, partially offset by incremental OM&A expenses as a result of changes to capitalization practices.

Table 1 below summarizes the impact on revenue requirement resulting from the accounting updates outlined in this exhibit.

Table 1: Impacts Summary – Revenue Requirement

Revenue Requirement Components	2011 Test	Increase/ (Decrease)	2011 Accounting Update	Exhibit Reference
Capital Expenditures	**498.0**	**(22.3)**	**475.7**	**Q1_T2_S2**
Working Capital	**318.4**	**2.3**	**320.7**	**Q1_T2_S3**
Total Rate Base	**2,346.3**	**14.2**	**2,360.5**	**Q1_T2_S4**
Cost of Capital	**164.9**	**1.0**	**165.9**	**Q1_T2_S5**
Total OM&A Expenses (1)	**226.8**	**22.6**	**249.4**	**Q1_T2_S6**
Depreciation and Amortization Expense	**178.3**	**(33.1)**	**145.2**	**Q1_T2_S7**
PILs	**28.1**	**(13.5)**	**14.6**	**Q1_T2_S8**
Service Revenue Requirement	**598.1**	**(23.1)**	**575.1**	**Q1_T2_S9**
Revenue Offsets	**19.7**	**-**	**19.7**	**Q1_T2_S9**
Base Distribution Revenue Requirement	**578.5**	**(23.1)**	**555.4**	**Q1_T2_S9**

Note:
(1) 2011 Accounting Update is inclusive of the LEAP adjustment of $0.6M increase to Charitable Donations as referenced in THESL's letter to the OEB dated November 8, 2010.

REVENUE REQUIREMENT COMPONENTS

Capital Expenditures

As a result of THESL's changes in estimate practices related to the capitalization of overhead and administrative costs, 2011 test year capital expenditures will decline by $22.3 million as compared to the amount previously presented in the August filing. The breakdown of this decrease is as follows:

Table 2: Capital Expenditures Decrease – 2011 Test Year (Accounting Update)

Category	Decrease in Capital Expenditures ($ millions)
Engineering Capital	13.7
Payroll Burden (SLR)	7.1
Stores Operation	1.1
Rolling Stock (VHR)	0.1
Allowance for Funds Used During Construction ("AFUDC")	0.4
Total Capital Expenditures Decrease	**22.3**

Note: Variances due to rounding may exist

As shown above in Table 2, in addition to the capital expenditures decreases resulting directly from the accounting estimate changes applied in 2011, AFUDC charges will also be reduced, as there is a direct downward impact on Construction Work in Progress eligible for AFUDC.

The reduction in capital expenditures of $22.3 million primarily impacts THESL's internally resourced operational investments which are presented in Exhibit Q2, Tab 2, Schedule 2, as an update to the 2011 Summary of Capital Budget. Projects within this category of the capital budget are affected by Engineering Capital support as well as by the SLRs of employees and material handling costs charged to these jobs.

Working Capital

The increase in working capital of $2.3 million due to the 2011 Accounting Update arises from the changes in OM&A and Income Tax amounts. These changes result in an updated Working Capital Allowance of $320.7 million. The calculations are shown in Exhibit Q1, Tab 2, Schedule 3.

Total Rate Base

As a result of the 2011 Accounting Update, total rate base has increased by $14.2 million. This is a combination of the increase in working capital as described above, coupled with the decrease in 2011 depreciation expense and offset by the decrease to in-service asset additions as a result of the 2011 capital expenditures decrease also discussed above.

THESL has updated the relevant fixed asset continuity, CWIP continuity, and rate base tables resulting from the 2011 Accounting Update in Exhibit Q1, Tab 2, Schedules 4-1 through 4-7.

Cost of Capital

The 2011 Accounting Update impacts the cost of capital through the change in Rate Base. While Return on Equity Rate is unchanged (and will be determined by the OEB's ROE mechanism for 2011), the higher rate base results in an increase of the overall Cost of Capital component of Revenue Requirement of $1.0 million.

Exhibit Q1, Tab 2, Schedule 5 details the changes in Cost of Capital.

Total OM&A Expenses

The increase in OM&A expenses is directly correlated with the decrease in capital expenditures described above, less the AFUDC impact as this is a non-OM&A component.

Updates to relevant tables are presented in Exhibit Q1, Tab 2, Schedules 6-1 through 6-3.

Depreciation and Amortization Expense

The decrease in depreciation and amortization expense of $33.1 million is due to the change in accounting estimates applied in this 2011 Accounting Update. Refer to the above discussion in Accounting Update: Changes in Accounting Estimates for a summary of the changes implemented.

Updates to the depreciation expense table are presented in Exhibit Q1, Tab 2, Schedule 7-1.

PILs

The decrease in the PILs requirement of approximately $13.5 million is mainly attributable to differences between the tax and book treatment of various costs, particularly book depreciation of PP&E versus capital cost allowance. For tax purposes, depreciation expense is added back to net income, while capital cost allowance is deducted. As a result of the Accounting Update, depreciation is reduced by $33.1 million, while capital cost allowance is reduced by $0.5 million.

The updated PILs summary and model are presented in Exhibit Q1, Tab 2, Schedules 8-1 and 8-2, respectively.

Revenue by Class

The updated Service Revenue Requirement has been allocated to classes using the Cost Allocation Model. All assumptions in the model are unchanged from the originally filed model. Changes in the capital and OM&A components result in marginal changes in the percentage allocation to classes. Table 3 below shows the allocated costs as originally filed and with the 2011 Accounting Update.

Table 3: Allocated Costs (including Transformer Allowance)

	Allocated Costs – 2011 Test		Allocated Costs - Accounting Update	
	$ millions	% of Total	$ millions	% of Total
Residential	283.6	46.5%	269.2	45.9%
GS < 50 kW	81.2	13.3%	77.7	13.3%
GS 50-999 kW	148.9	24.4%	146.6	25.0%
GS 1000-4999 kW	46.4	7.6%	46.0	7.8%
Large Use	24.8	4.1%	24.2	4.1%
Streetlighting	19.6	3.2%	18.1	3.1%
Unmetered Scattered Load	5.2	0.9%	4.8	0.8%
TOTAL	**609.6**	**100%**	**586.7**	**100%**

The Revenue-Cost ratios have been maintained as originally filed for all classes, with the exception of the GS 50-999 kW class. Because of the changes in the overall revenue requirement, plus the changes in the allocated costs to each class, it is mathematically impossible to maintain the Revenue-Cost ratios for all classes exactly as per the original filing. The Revenue-Cost ratio for the GS 50-999 kW class, which is the highest of all classes, has been reduced slightly, as shown in the following Table 4.

Table 4: Revenue-Cost Ratios

	2011 Test	2011 Accounting Update
Residential	92.0	92.0
GS < 50 kW	100.0	100.0
GS 50-999 kW	114.6	113.9
GS 1000-4999 kW	111.0	111.0
Large Use	104.0	104.0
Streetlighting	77.7	77.7
Unmetered Scattered Load	86.1	86.1

The development of the rates from the updated Revenue Requirement and Revenue-Cost ratios maintains the fixed-variable split as originally filed (2011 fixed variable split maintained at 2010 approved levels, with the exception of the GS 1000-4999 kW and Large Use classes, where the fixed component has been lowered due to being higher than the ceiling level calculated in the Cost Allocation Model). The resulting rates, compared with the originally filed rates, are shown in Exhibit Q1, Tab 2, Schedule 10. The revenues to be collected, by class, are shown in Exhibit Q1, Tab 2, Schedule 11.

Summary of Bill Comparisons

A comparison of monthly bills and bill impacts by class is shown in Exhibit Q1, Tab 2, Schedule 12.

1 ***Previously filed as Exhibit D1, Tab 7, Schedule 1, Table 2***

2

3 **Table 1: Summary of Capital Budget ($ millions)**

	2008 Actual	2009 Actual	2010 Bridge	2011 Test	2011 Accounting Update
OPERATIONAL INVESTMENTS					
Sustaining Capital					
Underground Direct Buried	23.8	31.9	65.2	62.6	61.5
Underground Rehabilitation	38.2	36.7	32.1	49.8	48.6
Overhead	19.3	20.5	22.0	46.8	44.9
Network	4.7	5.0	5.5	15.1	14.7
Transformer Station	8.5	8.6	11.9	14.3	14.1
Municipal Substation Investment	8.3	5.5	6.8	8.2	8.0
Total Sustaining Capital	**102.9**	**108.2**	**143.6**	**196.8**	**191.8**
Reactive Work	19.3	20.7	19.4	22.2	21.4
Customer Connections	42.8	37.6	32.4	41.8	40.5
Customer Capital Contribution	(32.7)	(23.4)	(15.4)	(16.7)	(16.7)
Capital Contributions to HONI	0.4	0.3	2.8	15.0	15.0
Engineering Capital	26.4	25.8	30.9	39.4	25.7
AFUDC	2.0	2.8	4.8	6.6	6.2
Other	(4.3)	3.1	-	2.7	2.7
Total Operations	**156.8**	**175.1**	**218.4**	**307.7**	**286.7**
GENERAL PLANT					
Fleet &Equipment Services	7.9	9.9	9.9	13.3	13.3
Facilities	3.4	7.6	11.9	13.2	13.2
Other	0.3	3.2	3.1	2.7	2.7
Total GENERAL PLANT	**11.6**	**20.7**	**24.9**	**29.3**	**29.2**
CUSTOMER SERVICES					
Wholesale Metering	4.4	(0.5)	6.9	4.9	4.9
Smart Metering	5.6	2.6	-	12.6	12.2
Suite Metering	2.7	3.3	2.4	2.6	2.6
Other	0.5	0.3	0.6	0.5	0.4
Total CUSTOMER SERVICES	**13.2**	**5.6**	**9.9**	**20.6**	**20.2**
Total INFORMATION TECHNOLOGY	**24.1**	**35.7**	**28.8**	**32.8**	**32.7**
Total OPERATIONAL INVESTMENTS	**205.7**	**237.1**	**281.9**	**390.4**	**368.7**
EMERGING REQUIREMENTS					
Standardization	-	5.7	25.9	4.7	4.6
Downtown Contingency	-	-	13.1	5.4	5.3
FESI 7 / WPF	-	-	5.5	10.9	10.6
Smart Grid	-	-	3.0	1.3	1.3
Externally Initiated Plant Relocations	-	-	-	12.2	12.0
Stations System Enhancements	-	(1.0)	15.2	33.1	33.1
Secondary Upgrade	-	-	6.5	10.0	10.0
Energy Storage Project	-	-	-	30.0	30.0
Total EMERGING REQUIREMENTS		**4.7**	**69.2**	**107.7**	**106.9**
TOTAL CAPITAL	**205.7**	**241.7**	**351.1**	**498.0**	**475.7**

Table 1: Calculation of Working Capital - 2011 Test

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
1		**2011 Test Expenses ($ millions)**	**2011 Expenses Accounting Update ($ millions)**	**Working Capital Factor**			**Expenses * Working Capital Factor 2011 Test ($ millions)**	**Expenses * Working Capital Factor Accounting Update ($ millions)**
2	Cost of Power	2,242.1	2,242.1	10.6%			238.3	238.3
3	OM&A	226.8	249.5	14.1%			32.0	35.2
4	Interest on Long Term Debt	74.0	74.0	7.7%			5.7	5.7
5	Income and Capital Taxes	28.1	14.6	9.2%			2.6	1.3
6	DRC	170.9	170.9	10.5%			17.9	17.9
7	Sub-Total Working Capital Requirement						296.6	298.5
8	HST at 13%			Net Lag Days	2011 Test Expenses * Net Lag Days/365 * 13% HST	Accounting Update Expenses * Net Lag Days/365 * 13% HST		
9	Revenue	2,544.6	2,544.6	-18.5	-16.8	-16.8		
10	Cost of Power	2,242.1	2,242.1	43.6	34.8	34.8		
11	OM&A Expenses	226.8	249.5	46.9	3.8	4.2		
12	HST Working Capital Requirement						21.8	22.2
13	**2011 Total Working Capital**						**318.4**	**320.7**

Table 2: Working Capital Allowance ($ millions)

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2009 Historical	2010 Approved	2010 Bridge	2011 Test	2011 Accounting Update
1	Working Capital	266.8	273.6	277.4	318.4	320.7

RATE BASE

Previously filed as Exhibit D1, Tab 1, Schedule 1, Table 2

Table 1: Continuity of Fixed Assets Summary ($ millions)

Description	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Opening Balance	3,523.6	3,768.1	3,905.4	4,205.6	4,205.6
In-Service Additions	282.8	211.6	321.3	397.1	387.7
Reductions	(4.8)	(44.9)	(3.5)	0.0	0.0
Transfers	(33.5)	(29.4)	(17.6)	0.0	0.0
Closing Balance	3,768.1	3,905.4	4,205.6	4,602.8	4,593.4
Average Balance	3,645.9	3,836.8	4,055.5	4,404.2	4,399.5

CONTINUITY OF GROSS FIXED ASSETS

Previously filed as Exhibit D1, Tab 2, Schedule 1, Table 5

Table 1: Year Ending December 2011 – Accounting Update ($ millions)

	Opening Balance	Additions	Reductions	Transfers	Closing Balance	Average Balance
Land and Buildings	59.7	10.9	0.0	0.0	70.6	65.1
TS Primary Above 50	20.0	23.6	0.0	0.0	43.6	31.8
Distribution System	199.7	11.6	0.0	0.0	211.4	205.5
Poles and Wires	2,625.4	215.9	0.0	0.0	2,841.2	2,733.3
Line Transformers	691.7	32.7	0.0	0.0	724.3	708.0
Services and Meters	298.7	34.3	0.0	0.0	333.0	315.8
General Plant	135.2	8.0	0.0	0.0	143.2	139.2
Equipment	160.4	18.4	0.0	0.0	178.9	169.7
IT Assets	216.3	43.1	0.0	0.0	259.4	237.8
Other Distribution Assets	70.1	2.1	0.0	0.0	72.2	71.1
Contributions and Grants	(271.5)	(12.9)	0.0	0.0	(284.4)	(277.9)
Total In-Service Assets	**4,205.6**	**387.7**	**0.0**	**0.0**	**4,593.4**	**4,399.5**

Note: Variances due to rounding may exist

DISTRIBUTION ASSETS – VARIANCE ANALYSIS

Previously filed as Exhibit D1, Tab 3, Schedule 2, Table 1

Table 1: Years Ending December 31 – Historical, Bridge and Test Years
($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Land and Buildings	53.0	48.8	53.8	65.1	65.1
TS Primary above 50	11.9	11.9	16.0	31.8	31.8
Distribution System	164.3	191.6	200.8	206.5	205.5
Poles and Wires	2,283.1	2,412.9	2,547.3	2,735.1	2,733.3
Transformers	590.5	623.5	665.3	709.9	708.0
Service and Meters	246.3	258.3	281.8	316.5	315.8
General Plant	118.9	120.8	128.3	139.2	139.2
Equipment	148.0	149.0	152.7	169.7	169.7
Information Technology	178.6	185.2	197.2	237.8	237.8
Other Distribution Assets	63.9	68.2	69.6	71.3	71.1
Contributions and Grants	(212.7)	(233.5)	(257.1)	(278.8)	(277.9)
Gross Assets	**3,645.9**	**3,836.8**	**4,055.5**	**4,404.2**	**4,399.5**
Accumulated Depreciation	(1,942.7)	(2,069.5)	(2,205.2)	(2,376.3)	(2,359.7)
Net Assets	**1,703.2**	**1,767.3**	**1,850.3**	**2,027.9**	**2,039.8**

Note: Variance due to rounding may exist.

1 **Table 2: 2011 Test versus Accounting Update ($ millions)**

	2011 Test	2011 Accounting Update	Variance ($)	Variance (%)
Land and Buildings	65.1	65.1	-	-
TS Primary above 50	31.8	31.8	-	-
Distribution System	206.5	205.5	(1.0)	(0.5)
Poles and Wires	2,735.1	2,733.3	(1.9)	(0.1)
Transformers	709.9	708.0	(1.9)	(0.3)
Service and Meters	316.5	315.8	(0.6)	(0.2)
General Plant	139.2	139.2	-	-
Equipment	169.7	169.7	-	-
Information Technology	237.8	237.8	-	-
Other Distribution Assets	71.3	71.1	(0.2)	(0.2)
Contributions and Grants	(278.8)	(277.9)	0.9	(0.3)
Gross Assets	**4,404.2**	**4,399.5**	**(4.7)**	**(0.1)**
Accumulated Depreciation	(2,376.3)	(2,359.7)	16.6	(0.7)
Net Assets	**2,027.9**	**2,039.8**	**11.9**	**0.6**

SUMMARY CONTINUITY OF GROSS FIXED ASSETS

Previously filed as Exhibit D1, Tab 6, Schedule 1, Table 1

Table 1: Years Ending December 31 ($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Opening Balance	3,523.6	3,768.1	3,905.4	4,205.6	4,205.6
In-Service Additions	282.8	211.6	321.3	397.1	387.7
Disposals	(4.8)	(44.9)	(3.5)	0.0	0.0
Transfers	(33.5)	(29.4)	(17.6)	0.0	0.0
Closing Balance	3,768.1	3,905.4	4,205.6	4,602.8	4,593.4
Average Balance	3,645.9	3,836.8	4,055.5	4,404.2	4,399.5

Note: Variances due to rounding may exist

CONTINUITY OF CONSTRUCTION WORK IN PROGRESS (“CWIP”)

Previously filed as Exhibit D1, Tab 6, Schedule 2, Table 1

Table 1: Years Ending December 31 ($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Opening Balance	130.1	81.7	128.9	182.7	182.7
Net Expenditures / (In Service)[1]	(48.4)	47.2	53.8	99.7	84.7
Closing Balance	81.7	128.9	182.7	282.4	267.3
Average Balance	105.9	105.3	155.8	232.5	225.0

Note: Variances due to rounding may exist

[1] Represents capital expenditures net of in-service transfers.

CONTINUITY OF FIXED ASSETS ACCUMULATED DEPRECIATION

Previously filed as Exhibit D1, Tab 6, Schedule 3, Table 1

Table 1: Years Ending December 31 ($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Opening Balance	1,871.0	2,014.3	2,124.6	2,285.7	2,285.7
Additions	149.0	155.5	164.5	181.1	148.0
Reductions	(4.7)	(44.8)	(3.4)	0.0	0.0
Transfers	(1.0)	(0.3)	0.0	0.0	0.0
Closing Balance	2,014.3	2,124.6	2,285.7	2,466.8	2,433.7
% of Gross Asset Value	53.5%	54.4%	54.3%	53.6%	53.0%
Average Balance	1,942.7	2,069.5	2,205.2	2,376.3	2,359.7

ACCUMULATED AMORTIZATION AS A PERCENTAGE OF GROSS FIXED ASSETS

Previously filed as Exhibit D1, Tab 6, Schedule 4, Table 4

Table 4: Year Ending December 2011 – Accounting Update ($ millions)

Accumulated Depreciation	Closing Balance	Percentage of Gross Assets
Land and Buildings	19.4	27.4%
TS Primary Above 50	5.5	12.6%
Distribution System	99.3	47.0%
Poles and Wires	1,438.9	50.6%
Line Transformers	377.4	52.1%
Services and Meters	140.6	42.2%
General Plant	62.9	43.9%
Equipment	120.8	67.5%
IT Assets	181.6	70.0%
Other Distribution Assets	47.9	66.4%
Contributions and Grants	(60.7)	21.3%
Non-Distribution Assets	-	n/a
Total In-Service Assets	**2,433.7**	**53.0%**

Note: Variances due to rounding may exist

Summary of Cost of Capital

Table 1: 2011 Test

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7
1	**Particulars**	**Utility Capital Structure 2011 Test ($ millions)**	**Utility Capital Structure Accounting Update ($ millions)**	**Deemed Structure**	**Cost Rate**	**Requested Return on Rate Base 2011 Test ($ millions)**	**Requested Return on Rate Base Accounting Update ($ millions)**
2		**(A)**	**(B)**		**(C)**	**(A) * (C)**	**(B) * (C)**
3	Long Term Debt	1,313.9	1,321.9	56.0%	5.37%	70.6	71.0
4	Unfunded Short Term Debt	93.9	94.42	4.0%	2.07%	1.9	2.0
5	Total Debt	1,407.8	1,416.31	60.0%	5.18%	72.5	72.9
6							
7	Preferred Shares						
8	Common Equity	938.5	944.2	40.0%	9.85%	92.5	93.0
9	Total Equity	938.5	944.2	40.0%	9.91%	92.5	93.0
10	Total Rate Base	2,346.3	2,360.5	100.0%	7.03%	165.0	166.0

SUMMARY OF THESL ADMINISTRATIVE AND GENERAL (“A&G”) EXPENDITURES

Previously filed as Exhibit F2, Tab 1, Schedule 1, Table 1

Table 1: Distribution Expenses Administrative and General ($ millions)

	2008 Actual	2009 Actual	2010 Bridge	2011 Test	2011 Accounting Update
Governance	14.9	11.9	5.0	1.9	1.9
Charitable Contributions (1)	0.1	0.2	0.3	0.1	0.7
Finance	4.3	4.5	10.5	15.3	15.4
Treasury, Rates and Regulatory	9.9	12.2	13.2	14.9	14.9
Legal	3.1	2.9	4.5	5.0	5.0
Communications	4.3	3.6	3.9	4.3	4.4
Information Technology	21.4	22.8	23.7	24.9	25.5
Organizational Effectiveness & Environmental Health and Safety	9.7	12.2	11.9	15.2	15.2
Strategic Management	0.1	1.4	2.3	1.7	1.7
Total	**68.9**	**71.7**	**75.4**	**83.3**	**84.7**

Note:

(1) 2011 Accounting Update is inclusive of the LEAP adjustment of $0.6M increase to Charitable Donations as referenced in THESL’s letter to the OEB dated November 8, 2010.

DISTRIBUTION EXPENSES OPERATIONS AND MAINTENANCE

Previously filed as Exhibit F1, Tab 1, Schedule 1, Table 2

Table 1: Summary of Distribution O&M Budget ($ millions)

Description	2008 Actual	2009 Actual	2010 Bridge	2011 Test	2011 Accounting Update
Maintenance Programs	26.8	33.3	34.0	37.1	35.5
Fleet and Equipment Services	9.2	10.9	11.6	13.7	13.6
Facilities and Asset Management	25.4	22.9	25.6	27.0	27.1
Supply Chain Services	8.4	8.8	9.3	11.4	11.4
Control Center	7.2	7.0	7.7	7.5	9.7
Operations Support	37.1	37.1	43.8	45.7	64.1
Customer Services	41.0	46.1	47.6	50.3	51.3
Customer Driven Operating	0.8	0.7	0.1	0.5	0.5
Total	155.9	166.9	179.6	193.3	213.2

DISTRIBUTION EXPENSES

Previously filed as Exhibit D1, Tab 3, Schedule 1, Table 1

Table 1: Distribution Expense Summary ($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Operations	45.7	49.0	61.6	62.8	82.3
Maintenance	41.3	46.5	42.6	45.6	46.2
Billing and Collections	31.9	35.1	33.7	35.3	35.3
Community Relations	3.5	5.5	3.7	4.1	4.1
Administrative and General (1)	46.1	47.3	60.6	72.2	74.6
Other Distribution Expenses	14.0	11.8	8.7	6.8	6.8
Amortization Expense	149.0	155.5	164.5	178.3	145.2
TOTAL	331.6	350.7	375.4	405.1	394.5

Note:

(1) 2011 Accounting Update is inclusive of the LEAP adjustment of $0.6M increase to Charitable Donations as referenced in THESL's letter to the OEB dated November 8, 2010.

1 **Table 2: 2011 Accounting Update versus 2011 Test ($ millions)**

	2011 Test	2011 Accounting Update	Variance ($)	Variance (%)
Operations	62.8	82.3	19.5	31.1
Maintenance	45.6	46.2	0.6	1.3
Billing and Collections	35.3	35.3	-	-
Community Relations	4.1	4.1	-	-
Administrative and General	72.8	74.6	1.8	2.5
Other Distribution Expenses	6.8	6.8	-	-
Amortization Expense	178.3	145.2	(33.1)	(18.6)
TOTAL	405.7	394.5	(11.2)	(2.7)

DEPRECIATION EXPENSE

Previously filed as Exhibit D1, Tab 13, Schedule 1, Table 1

Table 1: Years Ending December 31 ($ millions)

	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Distribution Plant	103.9	107.9	115.1	122.3	**86.5**
Information Technology	17.1	18.0	17.6	23.3	**23.4**
Services and Meters	10.6	11.8	12.2	13.7	**12.1**
Equipment, Vehicles, and Other	17.5	17.7	19.7	19.0	**23.2**
Total	**149.0**	**155.5**	**164.5**	**178.3**	**145.2**

Note: Variances due to rounding may exist

Toronto Hydro Electric System
Useful Life of Assets

Kinectrics Inc. Report No: K-418021-RA-0001-R002

August 28, 2009

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DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Toronto Hydro Electric System.

Toronto Hydro Electric System
Useful Life of Assets

Kinectrics Inc. Report No: K-418021-RA-0001-R002

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Revision History

Revision Number	Date	Comments	Approved
R000	August 21, 2009	Initial Draft	n/a
R001	August 27, 2009	THESL comments incorporated.	n/a
R002	August 28, 2009	Final Report	Y. Tsimberg

Table of Contents

1 Executive Summary

1.1 Introduction

Local Distribution Companies (LDCs) own and operate a significant number of assets that are typically divided into various asset categories. Additionally, some assets are comprised of several main components that have differing degradation mechanisms and resultant useful life. It is therefore important for LDCs to properly account for the useful lives of assets and their components so that the proper assessments required under International Financial Reporting Standards (IFRS) can be conducted.

This report reviews the useful lives of the assets, and the respective components, that are applicable to Toronto Hydro Electric System Limited (THESL) and Street Lighting. This study is based on available industry information and Kinectrics Inc. (Kinectrics) experience. Useful lives are dependent on a number of factors; these are described in Section 1.4 of this report. These values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE) as listed in Section 54 of this report, and Kinectrics experience. The useful lives of assets do not generally follow standard distribution curves; they are derived from empirical statistics.

1.2 Project Scope

This report provides an in-depth evaluation of the useful lives of the assets that are owned and operated by THESL, as well as street lighting assemblies. The typical system(s) to which the asset belongs is given. These "parent" systems are: Overhead Lines (OH), Transmission Stations (TS), Municipal Stations (MS), and Underground Systems (UG). Furthermore, the long term degradation mechanism of each asset category is discussed. Where possible, assets are sub-categorized into components. Note that for an asset that is componentized, only components that have major influences on the useful life of the asset are given. For each asset or component, the following information is presented:

- End of life criteria
- Useful Life Range
- Typical Life
- Typical time-based maintenance intervals, if applicable

Section 1.4 provides definitions for the above terms, as well as descriptions of typical distribution system assets and asset components.

1.3 Project Execution Process

The project execution process entailed a number of steps to ensure that the industry-based information compiled by Kinectrics not only includes all the relevant assets and components used by THESL, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

1. The initial list of assets and components was produced by THESL and Street Lighting and provided to Kinectrics for review.

2. Upon review of the initial list, Kinectrics generated an intermediate asset list that had a somewhat different background, granularity, and componentization, based on industry practices and Kinectrics experience.

3. The intermediate list was reviewed by the THESL operations and Street Lighting and finalized in conjunction with Kinectrics to derive a "final" list.

4. For each asset and component in the "final" list, Kinectrics then gathered the information described in Section 1.2 using the methodology described in Section 1.1 of this report. A Draft Report that summarized the findings and provided detail descriptions, including degradation mechanisms and applicable assumptions for each asset, was produced.

5. THESL operations and Street Lighting reviewed the Draft Report and their comments and feedback were incorporated in this Final Report.

1.4 Definition of Terms

Typical Distribution System Asset
Typical distribution system assets include transformers, breakers, switches, underground cables, poles, vaults, cable chambers, etc. Some of the assets, such as power transformers, are rather complex systems and include a number of components.

Component
For the purposes of this study, component refers to the sub-category of an asset that meets both of the following criteria:

1. Its value is significant enough, relative to the asset value.

2. A need to replace the component does not necessarily warrant replacing the entire asset (i.e. different useful life for each component).

An *asset* may be comprised of more than one component, each with an independent failure mode and degradation mechanism that may result in a substantially different useful life than the overall asset. A component may also have an independent maintenance and replacement schedule.

End of Life Criteria
This is a condition that results in an asset not being able to perform its intended design functions, as a result of the long-term degradation of the asset or its component(s).

Useful Life
Useful Life refers to an estimated range of years during which an electric utility asset or its component is expected to operate as designed, without experiencing major functional degradation that requires major refurbishment or replacement.

In this report, the useful life range, in years, is presented in terms of a minimum, maximum, and typical value. An overwhelming number of units within a population will perform their intended design functions for a period of time greater than or equal to the *minimum* life. Conversely, an overwhelming number of units will cease to perform as designed at or beyond the *maximum* life. A majority of the population will have useful lives of around the *typical* life. For example, consider an asset class with a useful life range of 20 to 40 years, and a typical life of 30 years. An overwhelming majority of the units within this class will perform as required for at least 20 years. Very little number units will operate beyond 40 years. Finally, a majority of the units within the population will operate for approximately 30 years. Note that an asset category can have a typical life that is equal to either the maximum or minimum life. This is simply an indication that the majority of the units within a population will be operational for either the minimum or maximum years; i.e. the statistical data is skewed towards either the maximum or minimum values. The range in useful lives reflects differences in:

- Operating regimes
- Maintenance practices
- Environmental conditions
- Design specifications

Typical Life
Refers to the typical age at which the asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses.

Typical Time-based Maintenance Intervals
For the purposes of this report, time-based maintenance refers to either *Routine Inspections* (RI) or *Routine Testing/Maintenance* (RTM). Other maintenance techniques such as Condition Based Maintenance, Reliability Centered Maintenance, and more intrusive periodic overhauls are very much dependent on individual utility's maintenance strategy and practices and, as such, could not be included in compiling industry-wide typical values.

Typical time-based maintenance intervals will be given only for assets that are proactively maintained, i.e. assets for which useful life is affected by regular planned maintenance. This excludes assets that are not routinely maintained.

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives and time based maintenance schedules, for THESL's assets.

Table 1-1 THESL Summary of Componentized Assets

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years)			Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
					Min	Typical	Max		
2	Wood Pole (Fully Dressed)		OH	40 feet	40	44	50	RI	15
3	Concrete Pole		OH	40 feet	50	60	60	RI	15
4	Remotely Operated Overhead Switch		OH	Not Available	30	45	50	RTM	2
5	Manually Operated Overhead Switch		OH	600A, 28KV,SWITCH, MANUAL, UPRIGHT MTG	30	50	60	RTM	2
6	SCADAMATE Overhead Switch		OH	SWITCH, 28KV, 600A, SCADA CONTROLLED	30	45	50	RTM	2
7	Overhead Primary Conductor	Primary Bare	OH	WIRE 556 ASC (DAHLIA) AS PER THES SPEC	50	60	77		n/a
		Primary Tree Proof	OH	CABLE 336 ASC 15kV TREE PROOF	50	60	77		
8	Overhead Secondary Conductor		OH	TRIPLEX 2- 266.8 AL XLPEI 1- 3/0 stock code # 7155236	50	60	77		n/a
9	Pole Mounted Transformer		OH	POLEMOUNT, 1PH, 100KVA, 16kV	30	40	40		n/a
10	Lighting Assemblies (High Mast)	Pole (Highmast)	OH	Not Available	60	70	80	RTM	2
		Cabling		Not Available	40	40	60		2
		Luminaire		Not Available	20	25	30		2
11	Power Transformer (>10MVA, >50kV)	Overall	TS	75/100/125MVA, 230kV/28kV	32	45	55	RTM	2
		Winding			32	45	55		
		Bushing			12	15	20		
		Tap changer			20	30	30		
12	230 kV Steel Structures and Overhead Bus Work	Steel structure	TS	Cavanagh TS 230kV bus structure	35	50	100		n/a
		Busbar			30	60	60		
13	Outdoor Station Disconnect Switch (230 kV)		TS	1200A, 230kV	30	45	50	RTM	5-8

* **OH** = Overhead Lines System **TS** = Transmission Station **MS** = Municipal Station **UG** = Underground System
** **RI** = Routine Inspection **RTM** = Routine Testing/Maintenance

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years) Min	Typical	Max	Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
14	TS AC Station Service	Transformer	TS	300kVA	32	45	55	RTM	3
		LV Switchgear	TS	1600A	40	40	60		3
15	Power Transformer (>2.5MVA and <10MVA, <50kV)	Overall	MS	5/6.7MVA, 27.6/4kV	32	45	55	RTM	2
		Winding			32	45	55		
		Bushing			12	15	20		
		Tap Changer			20	30	30		
16	Station Steel structures and Overhead Bus Work (<50kV)		MS	Bus structure for 27.6kV/4kV for 2 of 5MVA transformers	35	50	100	RI	n/a
17	Outdoor Station Disconnect Switch (<50kV)		MS	600A, 27.6kV	30	45	50	RTM	5-8
18	MS AC Station Service	Transformer	MS	75kVA	32	45	55	RTM	3
		AC Panel	MS	200-275A	40	40	60		
19	DC Station Service	Overall	TS,MS		10	20	30	RTM	1
		Battery bank		85-100AH, 125V	10	20	30		
		Charger		To be matched with battery size	20	20	30		
20	Indoor Station Disconnect Switch (<50kV)		TS,MS	600A Gang, LBS, 4kV	30	45	50	RI	5-8
21	Oil Breaker (Outdoor)		TS,MS	1200A, 13.8kV	30	42	60	RTM	3
22	SF6 Breaker (Outdoor)		TS,MS	2500A, 13.8kV or 1200A, 27.6kV	30	42	60	RTM	3
23	Vacuum Breaker (Outdoor)		TS,MS	3000A, 13.8kV or 1200A, 27.6kV	30	40	60	RTM	3
24	Oil Breaker (Indoor)		TS,MS	1200A, 13.8kV	30	42	60	RTM	3
25	SF6 Breaker (Indoor)		TS,MS	1200A, 13.8kV	30	42	60	RTM	3
26	Vacuum Breaker (Indoor)		TS,MS	1250A, 13.8kV	30	40	60	RTM	3
27	Air Blast Breaker (Indoor)		TS,MS	1200A, 13.8kV	30	40	50	RTM	3
28	Air Magnetic Breakers (Indoor)		TS,MS	1200A, 13.8kV	25	40	60	RTM	3
29	Metalclad/Metal Enclosed Switchgear (Air)		TS, MS	3000A, 13.8kV	40	50	60	RTM	6
30	Metalclad/Metal Enclosed Switchgear (GIS)		TS, MS	3000A, 13.8kV	40	50	60	RTM	6
31	Station Grounding System		TS,MS	15 ground rods 100' x 100' lot 13.8kV station	25	40	50		n/a
32	Station Grounding Transformer		TS,MS	13.8kV, 250A per phase for 1 minute	30	40	40	RI	3
33	SCADA RTU		TS,MS	Medium station, 13.8kV, 30 feeders	15	20	30		n/a
34	Automatic Transfer Switch		UG	Not Available	30	45	50	RI	3
35	Network Transformer	Network Unit	UG	750kVA, 120/208V	20	35	50	RI	2
		Protector Unit	UG	3000A, 120/208V	20	35	40		2
36	Pad Mounted Transformer		UG	1PH, 100KVA, 16kV	30	40	40	RI	n/a
37	Vault Transformer		UG	1PH, 100KVA, 16kV	30	40	40	RI	2
38	Submersible Transformer		UG	1PH, 100KVA, 16kV	25	35	40	RI	2

* **OH** = Overhead Lines System **TS** = Transmission Station **MS** = Municipal Station **UG** = Underground System
** **RI** = Routine Inspection **RTM** = Routine Testing/Maintenance

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years)			Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
					Min	Typical	Max		
39	Network Vault	Overall	UG	2.3mW x 6.4mL x3.4mH (I.D.)	40	60	80	RTM	3
		Roof		2.3mW x 6.4mL	20	25	30	RTM	3
40	Radial Vault	Overall	UG	3.0m W x 8.5m L x 3.66m H (I.D.)	40	60	80	RTM	3
		Roof		3.0m W x 8.5m L	20	25	30	RTM	3
41	URD Vault	Overall	UG	1.5m W x 3.5m L x 2.1m H (I.D.)	40	60	80	RTM	3
		Roof		1.5m W x 3.5m L	20	25	30	RTM	3
42	Submersible Vault	Overall	UG	1.24m W x 2.26m L x 1.98m H (I.D.)	40	60	80	RTM	3
		Roof		1.24m W x 2.26m L	20	25	30	RTM	3
43	Cable Chamber	Overall	UG	2.5m W x 3.0m L x 2.5m Headroom (I.D.)	50	60	80	RTM	3
		Roof		2.5m W x 3.0m L	20	25	30	RTM	3
44	Duct Bank		UG	3W x2H	30	50	80		n/a
45	Padmounted Switchgear (SF6/Vacuum)		UG	Not currently in our standard coming soon, VISTA or SF6 Canada power	30	30	50	RI	3
46	Padmounted Switchgear (Air Insulated)		UG	SWITCHGEAR 600A, PADMOUNTED, MANUAL, PMH-11, 28kV stock code #6910012	20	20	40	RI	3
47	SF6/Vacuum Underground Switch		UG	Loadbreak, Vacuum, 3PH, 15KV, 200AMP, 2-WAY 1-SW or 3-WAY 3-SW	30	30	50	RI	3
48	UG Primary Cable (XLPE in Duct)		UG	1/0 AL 28KV TRXLPE ECNPEJ. AS PER stock code #7180052	40	40	60		n/a
49	UG Primary Cable (XLPE DB)		UG	1/0 AL 28KV TRXLPE ECNPEJ. AS PER stock code #7180052	20	25	25		n/a
50	UG Primary Cable (PILC)		UG	500 KCMIL 3C CU 15KV PILC, AS PER stock code #7160040	70	75	80		n/a

* **OH** = Overhead Lines System **TS** = Transmission Station **MS** = Municipal Station **UG** = Underground System
** **RI** = Routine Inspection **RTM** = Routine Testing/Maintenance

Report Section #	Asset Category	Componentization (Sub-category)	Parent*	Typical Asset Size	Useful Life (years)			Maintenance Type**	Time Based Maint Schedule (years) n/a = not applicable
					Min	Typical	Max		
51	UG Secondary Cable (In Duct)		UG	CABLE 500 KCMIL CU XLPE 600V AS stock code 7150274	40	40	60		n/a
52	UG Secondary Cable (DB)		UG	CABLE 500 KCMIL CU XLPE 600V AS stock code 7150274	20	25	25		n/a
53	Lighting Assemblies (Conventional)	Cabling	UG	Not Available	40	40	60	RI	4
		Civil (handwell, tap box)		Not Available	50	50	60		
		Pole		Not Available	40	50	60		
		Luminaire		Not Available	20	25	30		

* **OH** = Overhead Lines System **TS** = Transmission Station **MS** = Municipal Station **UG** = Underground System
** **RI** = Routine Inspection **RTM** = Routine Testing/Maintenance

2 Wood Pole (Fully Dressed)

The asset referred to in this category is the fully dressed wood pole. This includes the wood pole, crossarms, insulators, and brackets. As wood poles are the most common form of support for medium voltage overhead feeders and low voltage lines, a vast majority of the poles at THESL are wood poles. These poles range in size from 30 to 55 feet, with the typical pole being 40 feet.

The most significant component of this class is the wood pole itself. The wood species predominately used for distribution systems are Red Pine, Jack Pine, and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

2.1 Degradation Mechanism

The end of life criteria for wood poles includes loss of strength, functionality, or safety (typically due to rot, decay, or physical damage). As wood is a natural material the degradation processes are somewhat different from those which affect other physical assets on the electricity distribution systems. The critical processes are biological, involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot. As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage.

2.2 System Hierarchy

Wood poles are considered a part of the Overhead Lines system.

2.3 Useful Life and Typical Life

The useful life of the wood pole component ranges from 40 to 50 years, with a typical value of approximately 44 years [1].

2.4 Time Based Maintenance Intervals

The typical utility routine inspection interval for this asset is every 15 years.

3 Concrete poles

Although a vast majority of the poles at THESL are wood poles, a significant number of concrete poles are also in use. This asset category includes concrete poles, brackets, and insulators. These poles range in size from 30 to 55 feet, with the typical pole being 40 feet.

3.1 Degradation Mechanism

The most significant component in this class is the concrete pole itself. Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in), however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice, resulting in cracking and separation of the concrete. The spun concrete process used in manufacturing poles prevents moisture entrapment inside the pores. Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

3.2 System Hierarchy

Concrete poles are considered a part of the Overhead Lines system.

3.3 Useful Life and Typical Life

The useful life range of the concrete pole component is 50 to 60 years; the typical life is 60 years [2][3].

3.4 Time Based Maintenance Intervals

For a typical utility, the routine inspection schedule for this asset is every 15 years.

4 Remotely Operated Overhead Switch

This asset class consists of overhead line three-phase, gang operated switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. While some categories of the switches are rated for load interruption, others are designed to operate under no load conditions and operate only when the current through the switch is zero. Most distribution line switches are rated 600 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with the switch handle locked in open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Since they do not typically need to interrupt short circuit currents, disconnect switches are simple in design relative to circuit breakers.

4.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates. Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out, the switch operating mechanism may seize making the disconnect switch inoperable. In addition, when blades fall out of alignment, excessive arcing may result. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

4.2 System Hierarchy

Overhead switches are considered a part of the Overhead Lines system.

4.3 Useful Life and Typical Life

The useful life of remotely operated switches is in the range of 30 to 50 years; the typical life is 45 years [1].

4.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for this asset is every two years.

5 Manually Operated Overhead Switch

Like the remotely operated overhead switch, the primary function of this asset is to allow for isolation of overhead line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hookstick or manual gang. The manually operated switches used by THESL have typical ratings of 28 kV, 600A.

5.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with manually operated line switches include the following, with rate and severity depending on operating duties and environment:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

5.2 System Hierarchy

Overhead switches are considered a part of the Overhead Lines system.

5.3 Useful Life and Typical Life

The useful life of manually operated switches is in the range of 30 to 60 years; the typical life is 50 years [2].

5.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for manually operated overhead switches is two years.

6 SCADAMATE Overhead Switch

SCADAMATE switches are a type of overhead line switches that are can receive signals from and be monitored by the SCADA system. These units include the switch, communications, and RTU. As with other line switches, this asset allows for the isolation of overhead line sections or equipment for maintenance, safety, or other operating requirements. THESL's SCADAMATE switches have typical ratings of 28 kV, 600A.

6.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with manually operated line switches include the following:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment
- Loose connections
- Non functioning padlocks
- Insulators damage
- Missing ground connections
- Missing nameplates for proper identification

The rate and severity of degradation are a function on operating duties and environment:

6.2 System Hierarchy

Overhead switches are considered a part of the Overhead Lines system.

6.3 Useful Life and Typical Life

The useful life range of SCADAMATE switches is 30 to 50 years; the typical life is 45 years [1][4].

6.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for SCADAMATEs is two years.

7 Overhead Primary Conductor

Electrical current flows through distribution line conductors, facilitating the movement of power throughout the distribution system. These conductors are supported by either metal or wood structures to which they are attached by insulator strings suitable for the voltage at which the conductors operate. The conductors are sized for the amount of current to be carried and other design requirements. The overhead conductors typically used by THESL are Wire 556 ACS (DAHLIA) and Cable 336 ACS 15 kV Tree Proof.

7.1 Degradation Mechanism

To function properly, conductors must retain both their conductive properties and mechanical (i.e. tensile) strength. Aluminum conductors have three primary modes of degradation: corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor, as well as environmental and operating conditions. Most utilities find that corrosion and fatigue present the most critical forms of degradation.

Generally, corrosion represents the most critical life-limiting factor for aluminum-based conductors. Visual inspection cannot detect corrosion readily in conductors. Environmental conditions affect degradation rates from corrosion. Both aluminum and zinc-coated steel core conductors are particularly susceptible to corrosion from chlorine-based pollutants, even in low concentrations.

Fatigue degradation presents greater detection and assessment challenges than corrosion degradation. In extreme circumstances, under high tensions or inappropriate vibration or galloping control, fatigue can occur in very short timeframes. However, under normal operating conditions, with proper design and application of vibration control, fatigue degradation rates are relatively slow. Under normal circumstances, widespread fatigue degradation is not commonly seen in conductors less than 70 years of age. Also, in many cases detectable indications of fatigue may only exist during the last 10% of a conductor’s life.

In designing transmission lines, engineers ensure that conductors receive no more than 60% of their rated tensile strength (RTS) during heaviest anticipated weather loads. The tensile strength of conductors gradually decreases over time. When conductors experience unexpectedly large mechanical loads and tensions beyond 50% of their RTS, they begin to undergo permanent stretching with noticeable increases in sagging.

Overloading lines beyond their thermal capacity causes elevated operating temperatures. When operating at elevated temperatures, aluminum conductors begin to anneal and lose tensile strength. Each elevated temperature event adds further damage to the conductor. After a loss of 10% of a conductor’s RTS, significant sag occurs, requiring either resagging or replacement of the conductor. Because of their steel cores, Aluminum Conductor Steel Reinforced (ACSR) conductors can withstand greater annealing degradation than Aluminum Stranded Conductor (ASC).

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor’s aluminum strands, reducing strength at those sites and potentially leading to conductor failures. Visual inspection readily detects arcing damage.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

7.2 System Hierarchy

The overhead conductor asset class is a part of the Overhead Lines system.

7.3 Useful Life and Typical Life

The overhead primary conductor are of two types:

- Primary Bare
- Primary Tree Proof

7.3.1 Primary Bare

According to a utility study and Kinectrics experience, the useful life of overhead primary conductors is in the range of 50 to 77 years, with the typical life close to 60 years [5][6].

7.3.2 Primary Tree Proof

According to a utility study and Kinectrics experience, the useful life of overhead primary conductors is in the range of 50 to 77 years, with the typical life close to 60 years [5][6].

8 Overhead Secondary Conductors

Secondary Overhead Conductors are typically used in overhead lines (in circuits not exceeding 600 volt phase to phase) on poles or as feeders to residential premises. The typical secondary overhead conductor used by THESL is the Triplex 2-266.8 AL XLPEI 1–3/0.

8.1 Degradation Mechanism

Overhead secondary conductors have a similar degradation mechanism to primary overhead conductors. These conductors must retain both their conductive properties and mechanical strength. The primary modes of degradation are corrosion, fatigue, and creep. The degree of degradation is a function of conductor size, construction, and environmental and operating conditions.

Additional forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Birdcaging

8.2 System Hierarchy

The overhead secondary conductor asset class is a part of the Overhead Lines system.

8.3 Useful Life and Typical Life

According to a utility study and Kinectrics experience, the useful life of secondary overhead conductors is in the range of 50 to 77 years, with the typical life close to 60 years [5][6].

9 Pole Mounted Transformer

Transformers are static devices that perform step-up and step-down voltage change operations. Distribution line transformers change the medium or low distribution voltage to 120/240 V or other common voltages for use in residential and commercial applications. The pole mounted transformers used by THESL range from single phase, 50 kVA, 16 kV to single phase, 167 kVA, 16 kV, with the typical being single phase, 100 kVA, 16 kV.

9.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of time in service. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI/IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

9.2 System Hierarchy

The Pole Mounted Transformer asset class is a part of the Overhead Lines system.

9.3 Useful Life and Typical Life

In the Kinectrics study [7], it was found that the useful life of the pole mounted transformer is in the range of 30 to 40 years, with an average value of approximately 40 years.

10 Lighting Assemblies (High Mast)

High mast lighting is typically employed in areas where high and uniform levels of illumination, easy maintenance, and minimum ground level obstruction are required. They are, for example, used in roadways and highways. High-mast towers are constructed from welded tubular sections that taper towards the top. The masts are finished through a hot-dip galvanizing process and are therefore designed to withstand extreme weather conditions. The towers have welded base plates that are bolted to concrete foundations. A ring at the top of the towers holds multiple luminaires.

10.1 Degradation Mechanism

High mast towers are subject to environmental damage. Wind causes fatigue to all parts of the structure, including the anchor bolts and base-plate weld and vertical welds along the height of the structure. Rain, snow, and moisture from condensation result in corrosion, particularly to slip joints and in the vicinity of welded connections. The luminaires used in high mast systems degrade with age, electrical, mechanical, and environmental stresses (wind, heat, cold, etc).

10.2 System Hierarchy

High mast street lighting is a part of the Overhead Lines system.

10.3 Useful Life and Typical Life

The high mast lighting assemblies can be componentized into:

- High Mast Pole
- Cabling
- Luminaires

10.3.1 High Mast Pole

High Mast poles have a useful life range of 60 to 80 years; the typical life is 70 years [8].

10.3.2 Cabling

Cabling has a useful life range of 40 to 60 years; the typical life is 40 years [9][2].

10.3.3 Luminaires

Luminaires have a useful life range of 20 to 30 years; the typical life is 25 years.

10.4 Time Based Maintenance Intervals

The time based routine testing/maintenance interval for all components is every two years.

11 Power Transformer (>10 MVA, >50kV)

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, ratings may range from 30MVA to 125 MVA. The typical TS power transformer used by THESL is rated as follow: 75/100/125MVA, 230kV/28kV.

11.1 Degradation Mechanism

Transformers operate under many extreme conditions, and both normal and abnormal conditions affect their aging and breakdown. They are subject to thermal, electrical, and mechanical aging. Overloads cause above-normal temperatures, through-faults can cause displacement of coils and insulation, and lightning and switching surges can cause internal localized over-voltages.

For a majority of transformers, end of life is a result of the failure of insulation, more specifically, the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are complex mechanical devices and are therefore prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

11.2 System Hierarchy

Power transformers rated greater than 10MVA, 50 kV are considered a part of the Transmission Station system.

11.3 Useful Life and Typical Life

The overall useful life range of a power transformer at a transmission station is 32 to 55 years; the average life is 45 years.

This asset also has several major components, each of which has a different useful life. These are the transformer core, windings, insulating oil, bushings, and on-load tap changer. From a maintenance practice perspective, a power transformer can be componentized into the following:

- Winding system (including core, winding, and insulation oil)
- Bushing
- Tap Changer

11.3.1 Winding System

The useful life of the winding system can be in the range of 32-55 years [1], depending on the loading condition and ambient operating temperature, and routine maintenance practices. A typical life of 45 years can be expected for the winding system [11].

11.3.2 Bushings

According to research statistics, the useful life range of bushings is 12-20 years, with a typical life of15 years [12].

11.3.3 Tap Changer

The useful life range of the tap changer is 20-30 years; the typical life is 30 years [13][14].

11.4 Time Based Maintenance Intervals

For TS power transformers, the typical routine testing/maintenance interval is two years.

12 230 kV Steel Structures & Overhead Bus Work

There are a number of different types of structures at distribution stations for supporting buses and equipment. The predominant types are galvanized steel, either lattice or hollow sections.

12.1 Degradation Mechanism

Degradation or reduction in strength of steel structures can result from corrosion, structural fatigue, or gradual deterioration of foundation components.

Corrosion of lattice steel members and hardware reduces their cross-sectional area causing a reduction in strength. Similarly, corrosion of tubular steel poles reduces the effectiveness of the tubular walls. Rates of corrosion may vary, depending upon environmental and climatic conditions (e.g., the presence of salt spray in coastal areas or heavy industrial pollution).

Structural fatigue results from repeated structural loading and unloading of support members. Temperature variations, plus wind and ice loadings lead to changes in conductor tension. Tension changes result in structural load variations on angle and dead end towers. Other changes such as foundation displacements and breaks in wires, guys and anchors may result in abnormal tower loading.

Typically, steel pole foundations are cylindrical steel reinforced concrete structures with anchor bolts connecting the pole to its base. Common degradation processes include corrosion of foundation rebar, concrete spalling and storm damage.

Busbar degradation is mainly caused by thermal and mechanical stresses.

12.2 System Hierarchy

230 kV Steel Structures and Overhead Bus Work belong to the Transmission Station system.

12.3 Useful Life and Typical Life

This asset group can be componentized into the following:

- 230 kV Steel Structures
- 230 kV Overhead Busbars

12.3.1 230 kV Steel Structures

Based on statistical information from CIGRE, the useful life of steel towers is in the range of 35 to100 years [1]. The corrosion and structural fatigue that a structure experiences is influenced by the unique combination of environment and weather that it is subject to. As structures at different locations are exposed to varying environments, there is a wide useful life range for this asset component. Normally, a galvanized / painted steel tower has a life expectancy of 50 years [15][16].

12.3.2 230 kV Overhead Busbars

The useful life range of busbars is 30 to 60 years. According to the Kinectrics study [2], the typical life of high voltage overhead busbars is approximately 60 years.

13 Outdoor Station Disconnect Switch (230 kV)

This asset class consists of the 230 kV disconnect switches used to physically and electrically isolate sections of the power transmission system for the purposes of maintenance, safety, and other operational requirements. Outdoor air-insulated disconnect switches typically consist of manual or motor operated isolating devices mounted on support insulators and metal support structures. Many high voltage disconnect switches (e.g. line and transformer isolating switches) have motor-operators and the capability of remote-controlled operation. These switches are normally operated when there is no current through the switch, unless specifically designed to be capable of operating under load.

13.1 Degradation Mechanism

Disconnect switches have many moving parts that are subject to wear and operational stress. Except for parts contained in motor-operator cabinets, switch components are exposed to the ambient environment. Thus, environmental factors, along with operating conditions, vintage, design, and configuration all contribute to switch degradation. Critical degradation processes include corrosion, moisture ingress, and ice formation. A combination of these factors that may result in permanent damage to major components such as contacts, blades, bearings, drives and support insulators.

Generally, the following represent key end-of-life factors for disconnect switches:

- Decreasing reliability, availability, and maintainability
- High maintenance and operating costs
- Maintenance overhaul requirements
- Obsolete design, lack of parts and service support
- Switch age

Application criticality and manufacturer also play key roles in determining the end-of-life for disconnect switches. Generally, absent a major burnout, widespread deterioration of live components, support insulators, motor-operators, and drive linkages define the end-of-life for these switches. However, routine maintenance programs usually provide ample opportunity to assess switch condition and viability.

Disconnect switches have components fabricated from dissimilar materials, and use of these different materials influences degradation. For example, blade, hinge and jaw contacts may consist of combinations of copper, aluminum, silver and stainless steel, several of which have tin, silver and chrome plating. Further switch bases may consist of galvanized steel or aluminum.

Most disconnect switches have porcelain support and rotating insulators. The porcelain offers rigidity, strength and dielectric characteristics needed for reliability. However, excessive deflection or deformation of support or rotating stack insulators can cause blade misalignment and other problems, resulting in operational failures.

Disconnect switches must have the ability to open and close properly even with heavy ice build-up on their blades and contacts. However, these switches may sit idle for several months or more. This infrequent operation may lead to corrosion and water ingress damage, increasing the potential for component seizures. Bearings commonly seize from poor lubrication and sealing, despite manufacturers' claims that such components are sealed, greaseless and maintenance-free for life.

Normally, when blades enter or leave jaw contacts, they rotate to clean accumulated ice from contact surfaces. To accomplish this, hinge ends have rotating or other current transfer contacts. These contacts are often simple, long-life copper braids. However, some switches have more complex rotating contacts in grease-filled chambers. Without proper maintenance these more complex switches may degrade, causing blade failures.

13.2 System Hierarchy

The 230 kV station disconnect switch is a part of the Transmission Station system.

13.3 Useful Life and Typical Life

This asset has a useful life range of 30 to 50 years; the typical life is 45 years [1].

13.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is every 5-8 years. Utilities will typically increase diagnostic testing to justify the increase of maintenance intervals.

14 Transmission Station (TS) AC Station Service

The AC station service is the supply system that provides power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the transmission station. The most reliable source of such power is directly from the transmission or distribution lines. Small power transformers are configured to provide this requirement. In addition to the transformer, low voltage (LV) switchgear is another major component of the AC station service. The transformer typically used by THESL is rated at 300 kVA; the switchgear rating is 1600A.

14.1 Degradation Mechanism

The degradation of the TS AC station service is closely related to the degradation of the switchgear and transformer. Switchgear degradation is a function of a number of different factors, such as the condition of mechanical mechanisms and interlocks, degradation of solid insulation, and general degradation/corrosion. In most cases end of life is related to non-conditional issues, such as capability, obsolescence, or specific/generic defects.

For a majority of transformers, end of life is a result of insulation failure. Oil and paper insulation degrade because of oxidation, and factors that impact the rate of oxidation are the presence of oxygen, high temperature, and moisture. Particles and acids, as well as static electricity in oil cooled units, also affect the insulation.

14.2 System Hierarchy

The TS AC station service class is a part of the Transmission Station system.

14.3 Useful Life and Typical Life

TS AC Station Service can be componentized into the following:

- Transformer
- LV Switchgear

14.3.1 Transformer

The station service transformer has a useful life range of 32 to 55 years; the typical life is 45 years [1][11].

14.3.2 LV Switchgear

The station service LV switchgear has a useful life range of 40 to 60 years. The typical life is 40 years [1].

14.4 Time Based Maintenance Intervals

This asset class has a routine testing/maintenance interval of three years.

15 Power Transformer (>2.5MVA and <10MVA), <50kV)

Power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA. The typical distribution transformers used by THESL are rated as follows: 5/6.7MVA, 27.6/4kV.

15.1 Degradation Mechanism

The degradation of the power transformers at municipal stations or at customer sites is similar to that of the transformers at transmission stations. These transformers are subject to electrical, thermal, and mechanical aging. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

Tap changers and bushing are major components of the power transformer. Tap changers are prone to failure resulting from either mechanical or electrical degradation. Bushings are subject to aging from both electrical and thermal stresses.

15.2 System Hierarchy

These power transformers are a part of the Muncipal Station system.

15.3 Useful Life and Typical Life

The useful life of power transformers rated between 2.5 MVA and 10 MVA is 32 to 55 years; the typical life is 45 years.

The power transformer also has major components that have different useful lives. Componentization is as follows:

- Winding
- Bushing
- Tap Changer

15.3.1 Winding

The useful life of windings is 32 to 55 years; the typical life is 45 years [1][11].

15.3.2 Bushings

The useful life of bushings is 12 to 20 years; the typical life is 15 years [12].

15.3.3 Tap Changer

The useful life range of the tap changer is 20 to 30 years; the typical life is 30 years [13][14].

15.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for these transformers is two years.

16 Station Steel Structures & Overhead Bus Work (<50kV)

There are a number of different types of structures at distribution stations for supporting buses and equipment. The predominant types are galvanized steel, either lattice or hollow sections. A typical unit of this asset class is a bus structure for 27.6 kV/4KV for two of 5 MV transformers.

16.1 Degradation Mechanism

Degradation of this asset class is similar to the degradation of steel structure and overhead bus work for 230 kV. Reduction in steel strength is a result of corrosion, structural fatigue, or deterioration of foundation components. Corrosion, which can be accelerated by environmental condition, affects lattice steel members and tubular steel walls. Structural fatigue results from wind or ice loading and unloading of support members. Concrete foundations are also subject to deterioration.

16.2 System Hierarchy

Station steel structures and overhead bus work (<50kV) are a part of the Municipal Station system.

16.3 Useful Life and Typical Life

Based on statistical information from CIGRE, the useful life of steel towers is in the range of 35 to100 years [1]. The corrosion and structural fatigue that a structure experiences is influenced by the unique combination of environment and weather that it is subject to. As structures at different locations are exposed to varying environments, there is a wide useful life range for this asset component. Normally, a galvanized / painted steel tower has a life expectancy of 50 years [15][16].

17 Outdoor Station Disconnect Switch (<50kV)

Under normal operating conditions, disconnect switches isolate various other equipment from system voltages. Outdoor air-insulated disconnect switches typically consist of manual or motor operated isolating devices mounted on support insulators and metal support structures. These switches are normally operated when there is no current through the switch, unless specifically designed to be capable of operating under load. The typical disconnect switch (rated below 50 kV) used by THESL are rated 600A, 27.6kV.

17.1 Degradation Mechanism

The outdoor disconnect switch rated below 50 kV has a similar degradation process to that of the disconnect switch rated at 230 kV. These switches, having many moving parts, are subject to wear and operational stress. The components that are outside of the motor operating cabinets are also exposed to the environment.

Environmental factors, operating condition, vintage, design, and configuration contribute to switch degradation. Corrosion, moisture ingress, and ice formation can cause damage or misalignments to major components. The following represent key end-of-life factors for disconnect switches:

- Decreasing reliability, availability, and maintainability
- High maintenance and operating costs
- Maintenance overhaul requirements
- Obsolete design, lack of parts and service support
- Switch age
-

17.2 System Hierarchy

Outdoor station disconnect switches rated below 50 kV are a part of the Municipal Station system.

17.3 Useful Life and Typical Life

The useful life range of this asset is 30 to 50 years; the typical life is 45 years [1].

17.4 Time Based Maintenance Intervals

Disconnect switches are subject to routine testing/maintenance every 5 to 8 years. Utilities will increase the intervals based on the frequency of interim diagnostic testing.

18 Municipal Station (MS) AC Station Service

The AC station service is the supply system that provides power to the auxiliary equipment, such as fans, pumps, heating, or lighting, in the distribution station. The most reliable source of such power is directly from the transmission or distribution lines. Small power transformers are configured to provide this requirement. The transformer typically used in THESL's MS AC station service is rated at 75 kVA.

18.1 Degradation Mechanism

Degradation of the MS AC station service is related to the end of life of the transformer. As with most transformers, end of life is typically a result of insulation failure, particularly paper insulation. The oil and paper insulation degrade as oxidation takes place in the presence of oxygen, high temperature, and moisture. Acids, particles, and static electricity also have degrading effects to the insulation.

18.2 System Hierarchy

The MS AC Station service is a part of the Municipal Station system.

18.3 Useful Life and Typical Life

This asset can be componentized into the following:

- Transformer
- AC Panel

18.3.1 Transformer

The transformer component has a useful life range of 32 to 55 years; the typical life is 45 years [1][11].

18.3.2 AC Panel

The AC Panel component has a useful life range of 40 to 60 years; the typical life is 40 years [2].

18.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset is three years.

19 DC Station Services

The DC station service asset class includes battery banks and chargers. Equipment within transmission and municipal stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power so the only guaranteed instantaneous power source must be DC, based on batteries.

19.1 Degradation Mechanism

Effective battery life tends to be much shorter than many of the major components in a station. The deterioration of a battery from an apparently healthy condition to a functional failure can be rapid. This makes condition assessment very difficult. However, careful inspection and testing of individual cells often enables the identification of high risk units in the short term.

It is well understood in the utility industry that regular inspection and maintenance of batteries and battery chargers is necessary. In most cases the explicit reason for carrying out regular maintenance inspection is to detect minor defects and rectify them. However, critical examination of trends in maintenance records can give an early warning of potential failures.

Despite the regular and frequent maintenance and inspection of battery systems, failures in service are still relatively frequent. For this reason, many utilities employ battery monitors and alarm systems. The earlier versions of these are still widely used and are relatively unsophisticated devices that measure basic battery parameters with pre-set alarm levels. More modern monitoring devices have the ability to identify a potential failure as it develops and to provide a warning.

Although battery deterioration is difficult to detect, any changes in the electrical characteristics or observation of significant internal damage can be used as sensitive measures of impending failure. Batteries consist of multiple individual cells. While the significant deterioration/failure of an individual cell may be an isolated incident, detection of deterioration in a number of cells in a battery is usually the precursor to widespread failure and functional failure of the total battery.

Battery chargers are also critical to the satisfactory performance of the whole battery system. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the batteries themselves. Nevertheless, problems do occur. As with other electronic devices, it is difficult to detect deterioration prior to failure. It is normal practice during the regular maintenance and inspection process to check the functionality of the battery chargers, in particular the charging rates. Where any functional failures are detected it would be normal to replace the battery charger.

19.2 System Hierarchy

DC station services belong to both Transmission and Municipal Station systems.

19.3 Useful Life and Typical Life

The overall useful life of the DC station service is 10 to 30 years, with a typical life of 20 years.

This asset also has two major components that have differing useful lives:

- Battery Banks
- Charger

19.3.1 Battery Bank

The battery bank has a useful life range of 10 to 30 years; typical life is 20 years [2][17].

19.3.2 Charger

The charger has a useful life range of 20 to 30 years; typical life is 20 years [18][19].

19.4 Time Based Maintenance Intervals

Typically, routine testing/maintenance for batteries is conducted annually. The maintenance of schedule battery chargers is typically coordinated that of the battery.

20 Indoor Station Disconnect Switch (<50kV)

Under normal operating conditions, disconnect switches isolate various other equipment from system voltages. The typical indoor disconnect switch (rated below 50 kV) used by THESL are rated 600A Gang, LBS, 4 kV.

20.1 Degradation Mechanism

Like other types of switches, this asset, having many moving parts, is subject to wear and operational stress. The following represent key end-of-life factors for disconnect switches:

- Decreasing reliability, availability, and maintainability
- High maintenance and operating costs
- Maintenance overhaul requirements
- Obsolete design, lack of parts and service support
- Switch age

20.2 System Hierarchy

Indoor station disconnect switches rated below 50 kV are a part of the Transmission and Municipal Station system.

20.3 Useful Life and Typical Life

The useful life range of this asset is 30 to 50 years; the typical life is 45 years [1].

20.4 Time Based Maintenance Intervals

Disconnect switches are subject to routine testing/maintenance every 5 to 8 years. Utilities will increase the intervals based on the frequency of interim diagnostic testing.

21 Oil Circuit Breaker (Outdoor)

Circuit breakers are automated switching devices that can make, carry and interrupt electrical currents under normal and abnormal conditions. Circuit breakers at THESL are commonly used at transmission or distribution stations for switching 27.6, 13.8 or 4.16 kV feeders. Breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage.

The oil circuit breakers (OCB) which represent the oldest type of breaker design, have been in use for over 70 years. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium) and minimum oil breakers (in which oil provides the arc quenching function only). The typical outdoor breaker used by THESL is rated 1200A, 13.8 kV.

21.1 Degradation Mechanism

The key degradation processes associated with OCBs are as follows:

- Corrosion
- Effects of moisture
- Mechanical
- Bushing deterioration

The rate and severity of these degradation processes is dependent on a number of inter-related factors, in particular the operating duties and environment in which the equipment is installed. Often the critical degradation process is either corrosion or moisture ingress or a combination of the two, resulting in degradation to internal insulation, deterioration of the mechanism affecting the critical performance of the breaker, damage to major components such as bushings or widespread degradation to oil seals and structurally components.

Recent international experience indicates that a significant area of concern is barrier-bushing deterioration resulting from moisture ingress. The Synthetic Resin Bonded Paper (SRBP) insulation absorbs the moisture, which can result in discharge tracking across its surface leading to eventual failure of the bushing. Oil impregnated paper bushings are particularly sensitive to moisture. Once moisture finds its way into the oil and then into the paper insulation, it is very difficult to remove and can eventually lead to failure. Significant levels of moisture in the main tank can lead to general degradation of internal components and in acute cases free water can collect at the bottom of the tank. This creates a condition where a catastrophic failure could occur during operation.

Corrosion of the main tank and other structural components is also a concern. One area that is particularly susceptible to corrosion is underneath the main tank on the “bell end”, this problem is common to both single and three tank circuit breakers.

Corrosion of the mechanical linkages associated with the OCB operating mechanism is also a widespread problem that can lead to the eventual seizure of the links.

A lesser mode of degradation, although still serious in certain circumstances, is pollution of bushings, particularly where the equipment is located by the sea or in a heavy industrial area.

Other areas of degradation include:

- Deterioration of contacts
- Wear of mechanical components such as bearings
- Loose primary connections
- Deterioration of concrete plinth affecting stability of the circuit breaker

21.2 System Hierarchy

Oil circuit breakers are used in both Transmission and Municipal Station systems.

21.3 Useful Life and Typical Life

The typical life range of the oil breaker asset class is 30 to 60 years; the typical life is 42 years [1][2].

21.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for oil breakers is three years.

22 SF6 Circuit Breaker (Outdoor)

The typical outdoor SF6 breaker used by THESL is rated at 2500A, 13.8 kV or 1200A, 27.6 kV

Sulfur hexafluoride (SF6) insulated equipment is a relatively young technology. The first SF6 equipment was developed in the late 1960s. After some initial design and manufacturing problems equipment was increasingly used to replace oil filled equipment with widespread adoption and utilization since the mid 1980s. One of the more remarkable features of SF6 is its performance when subjected to an arc, or during a fault operation. SF6 is extremely stable and even at the high temperatures associated with an arc, limited breakdown occurs. Furthermore, most of the products of the breakdown recombine to form SF6. Consequently, SF6 circuit breakers can operate under fault conditions many more times than oil breakers before requiring maintenance.

22.1 Degradation Mechanism

Failures relating to internal degradation and ultimate breakdown of insulation are limited to early life failures where design or manufacture led to specific problems. There is virtually no experience of failures resulting from long term degradation within the SF6 chambers. Failures and incorrect operations are primarily related to gas leaks and problems with the mechanism and other ancillary systems. Gas seals and valves are a potential weak point. Clearly, loss of SF6 or ingress of moisture and air compromise the performance of the breaker. As would be expected the earlier SF6 equipment was more prone to these problems. Seals and valves have progressively been improved in more modern equipment.

Many of the earlier breakers relied on hydraulic or pneumatic assisted mechanisms. These have proved problematic in some cases and contributed significantly to the higher failure rates associated with this generation of equipment. More recent equipment usually utilize spring assisted mechanisms that have proved more reliable and require less maintenance.

22.2 System Hierarchy

SF6 circuit breakers are used in both Transmission and Municipal Station systems.

22.3 Useful Life and Typical Life

The typical life range of the SF6 breaker is 30 to 60 years; typical life is 42 years [1][2].

22.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for SF6 breakers is three years.

23 Vacuum Circuit Breaker (Outdoor)

The typical outdoor vacuum breakers used by THESL are rated 3000A, 13.8 kV or 1200A, 27.6 kV.

Vacuum Breakers consist of fixed and moving butt type contacts in small evacuated chambers (i.e. bottles). A bellows attached to the moving contact permits the required short stroke to occur with no vacuum losses. Arc interruption occurs at current zero after withdrawal of the moving contact. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

23.1 Degradation Mechanism

Circuit breakers have many moving parts that are subject to wear and stress. They frequently "make" and "break" high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker's specific duties. The International Council on Large Electric Systems' (CIGRE) have identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete
- Maintenance overhaul requirements
- Circuit breaker age

Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor mounted circuit breakers, the following represent additional degradation factors:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problem in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breakers

23.2 System Hierarchy

Vacuum circuit breakers are used in both Transmission and Municipal Station systems.

23.3 Useful Life and Typical Life

The typical useful life range of the vacuum breaker is 30 to 60 years; the typical life is 40 years [2][20].

23.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for vacuum breakers is three years.

24 Oil Circuit Breaker (Indoor)

In addition to outdoor installations, oil circuit breakers can be found within metalcald switchgear. The typical oil breaker used by THESL is raged 1200A, 13.8 kV.

24.1 Degradation Mechanism

This type of circuit breaker has the same degradation mechanism as the outdoor oil breaker. Degradation processes are as follows:

- Corrosion
- Effects of moisture
- Mechanical
- Bushing deterioration

The rate and severity of these degradation processes are dependent on a number of factors, such as operating duties and environment.

24.2 System Hierarchy

Oil circuit breakers are used in both Transmission and Municipal Station systems.

24.3 Useful Life and Typical Life

The typical life range of the oil breaker asset class is 30 to 60 years; the typical life is 42 years [1][2].

24.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for oil breakers is three years.

25 SF6 Circuit Breaker (Indoor)

In addition to outdoor installations, SF6 circuit breakers can be found within metalcald switchgear. The typical indoor SF6 breaker used by THESL is rated at 1200A, 13.8 kV.

25.1 Degradation Mechanism

An indoor SF6 breaker within switchgear has a similar failure mode as an SF6 breaker installed outdoors. Failures are typically attributed to early life failure, as opposed to long term degradation. Failure and mal-operation are primarily attributed to gas leaks and problems with the mechanism

25.2 System Hierarchy

SF6 circuit breakers are used in both Transmission and Municipal Station systems.

25.3 Useful Life and Typical Life

The typical life range of the SF6 breaker is 30 to 60 years; typical life is 42 years [1][2].

25.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for SF6 breakers is three years.

26 Vacuum Circuit Breaker (Indoor)

In addition to outdoor installations, vacuum circuit breakers can be found within metalcald switchgear. The typical indoor vacuum breakers used by THESL are rated 1250A, 13.8 kV.

26.1 Degradation Mechanism

The vacuum breakers in this asset class have a similar degradation mechanism to outdoor vacuum breakers, where corrosion, moisture, bushing/insulator deterioration, and mechanical degradation are factors.

26.2 System Hierarchy

Vacuum breakers are used in both the Transmission and Municipal Station systems.

26.3 Useful Life and Typical Life

The typical useful life range of the vacuum breaker is 30 to 60 years; the typical life is 40 years [2][20].

26.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

27 Air Blast Circuit Breaker (Indoor)

Air-blast breakers use compressed air as the quenching, insulating and actuating medium. In normal operation, a blast of compressed air carries the arc into an arc chute where it is quickly extinguished. A combination cooler-muffler is often provided to cool ionized exhaust gases before they pass out into the atmosphere and to reduce noise during operation. The typical air blast breakers used by THESL are rated 1200A, 13.8 kV.

27.1 Degradation Mechanism

The air blast circuit breaker has a similar degradation to other types of circuit breakers. The key degradation processes associated with air blast circuit breakers are:

- Corrosion
- Effects of moisture
- Bushing/insulator deterioration
- Mechanical

Severity and rate are dependent on factors such as operating duty and environment. Corrosion is a problem for most types of breakers. It can degrade internal insulators, performance mechanisms, major components (e.g. bushings), structural components, and oil seals. Moisture causes degradation of the insulating system. Mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections
- Oil contamination and/or leakage
- Deterioration of concrete foundation affecting stability of breakers

27.2 System Hierarchy

Air blast breakers are used in both Transmission and Municipal Station systems.

27.3 Useful Life and Typical Life

The typical useful life range of the air blast breaker is 30 to 50 years; the typical life is 40 years [1].

27.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for air blast breakers is three years.

28 Air Magnetic Circuit Breaker (Indoor)

In air magnetic circuit breakers, magnetic blowout coils are used to create a strong magnetic field that draws the arc into specially designed arc chutes. The breaker current flows through the blowout coils and produces a magnetic flux. This magnetic field drives the arc against barriers built perpendicular to the length of the arc. The cross sectional area of the arc is thereby reduced, and its resistance is considerably increased. The surface of the barriers cool and de-ionize the arc, thus collaborating to extinguish the arc.

28.1 Degradation Mechanism

Air magnetic breakers have a similar degradation mechanism to other breakers in that corrosion, moisture, bushing/insulator deterioration, and mechanical degradation are factors.

28.2 System Hierarchy

Air magnetic circuit breakers are used in both Transmission and Municipal Station systems.

28.3 Useful Life and Typical Life

The typical useful life range of the air magnetic breaker is 25 to 60 years; the typical life is 40 years [34].

28.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for air magnetic breakers is three years.

29 Metalclad / Metal Enclosed Switchgear (Air)

Metalclad Switchgear consists of an assembly of retractable/racked switchgear devices that are totally enclosed in a metal envelope (metal-enclosed). These devices operate in the medium voltage range, from 4.16 to 36 kV. The typical units used at THESL are rated at 3000A, 13.8 kV. The switchgear includes breakers, disconnect switches, or fusegear, current transformers (CTs), voltage transformers (VTs) and occasionally some or all of the following: metering, protective relays, internal DC and AC power, battery charger(s), and AC station service transformation. The gear is modular in that each breaker is enclosed in its own metal envelope (cell). The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

29.1 Degradation Mechanism

Medium voltage metalclad switchgear is an integral part of all distribution and transmission systems. Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices). Degradation of the breaker used is also a factor.

Correct operation of the mechanism is critical in devices that make or break fault currents, i.e. the contact opening and closing characteristics must be within specified limits. The greatest cause of mal-operation of switchgear is related to mechanism malfunction. Deterioration due to corrosion or wear due to lubrication failure may compromise mechanism performance by either preventing or slowing down the operation of the breaker. This is a serious issue for all types of switchgear.

In older air filled equipment, degradation of active solid insulation (for example drive links) has been a significant problem for some types of switchgear. Some of the materials used in this equipment, particularly those manufactured using cellulose-based materials (pressboard, SRBP, laminated wood) are susceptible to moisture absorption. This results in a degradation of their dielectric properties that can result in thermal runaway or dielectric breakdown. An increasingly significant area of solid insulation degradation relates to the use of more modern polymeric insulation. Polymeric materials, which are now widely used in switchgear, are very susceptible to discharge damage. These electrical stresses must be controlled to prevent any discharge activity in the vicinity of polymeric material. Failures of relatively new switchgear due to discharge damage and breakdown of polymeric insulation have been relatively common over the past 15 years.

Temperature, humidity and air pollution are also significant degradation factors, so indoor units tend to have better long-term performance. The safe and efficient operation of switchgear and its longevity may all be significantly compromised if the substation environment is not adequately controlled. In addition, the air switchgear can tolerate less number of full fault operations before maintenance is required.

29.2 System Hierarchy

Metalclad switchgear are used in both the Transmission and Municipal Station systems.

29.3 Useful Life and Typical Life

The useful life range of air insulated metalclad/metal enclosed switchgear is 40 to 60 years; the typical life is 50 years [2].

29.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is 6 years.

30 Metalclad / Metal Enclosed Switchgear (GIS)

The latest design of metalclad gear is the Gas Insulated Switchgear (GIS), which uses low-pressure SF6 gas as a general insulation medium, as a replacement for the air. The insulation within the metal enclosure is not necessarily the same as the working fluid in the breakers themselves, which presently is either SF6 or vacuum. The typical units used by THESL are rated 300A, 13.8 kV.

30.1 Degradation Mechanism

Switchgear degradation is a function of a number of different factors: mechanism operation and performance, degradation of solid insulation, general degradation/corrosion, environmental factors, or post fault maintenance (condition of contacts and arc control devices).

The mechanism must operate correctly in devices that break charges, loads and fault currents. Generally, mechanism malfunction causes most operational problems in GIS. Corrosion and lubrication failure may compromise mechanism performance by preventing or slowing its operation.

Solid insulation such as that in entrance bushings, internal support insulators, plus breaker and switch operating rods have caused many GIS failures. Manufacturing, shipping, installing, maintaining and operating the GIS can cause defects in the insulation. Defects include voids in epoxy insulators, delamination of epoxy and metallic hardware, and protrusions on conductors. In floating components, fixed and moving particles can lead to failures. Partial discharge (PD) activity usually leads to flashovers.

Corrosion and general deterioration increase risks of moisture ingress and SF6 leaks, particularly in outdoor GIS. If not treated, these factors may cause the end-of-life for GIS.

GIS is designed and manufactured for outdoor use, but it generally has better long-term performance when installed indoors. Outdoor GIS, particularly older ITE designs, have higher than acceptable SF6 gas leaks because of the poor quality of fittings, connectors, valves, by-pass piping, general enclosure porosity and flange corrosion. Indoor installations reduce problems from corrosion, moisture ingress, low ambient temperatures and SF6 leaks.

GIS have more costly, difficult and time-consuming post fault maintenance requirements than air insulated switchgear. Older GIS have even more post-fault maintenance problems. Accessibility, fault location, fault level and duration, degree of compartmentalization, isolation requirements, pressure relief, burn-through protection, parts and service capabilities all help determine post-fault maintenance needs.

30.2 System Hierarchy

Metalclad Switchgear are used in both the Transmission and Municipal Station systems.

30.3 Useful Life and Typical Life

The useful life range of GIS insulated metalclad/metal enclosed switchgear is 40 to 60 years; the typical life is 50 years [2].

30.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is 6 years.

31 Station Grounding System

Grounding systems in stations dissipate maximum ground fault currents without interfering with power system operation or causing voltages dangerous to people or equipment. Safety hazards from inadequate grounding include excessive ground potential rises and excessive step and touch potentials. Generally, grounding system assets provide suitable paths for ground currents to follow from power equipment and conductors into the earth. Consequently, complete grounding systems include buried conductors, ground rods and connections, plus soil and vegetation in the area. Soil and vegetative conditions affect water retention and drainage, which impact overall performance of the grounding system. Typical THESL installations include 15 ground rods in a 100’ x 100’ lot at 13.8 kV stations.

31.1 Degradation Mechanism

Transmission station grounding systems keep ground potential rise, step and touch potentials below specified limits when maximum (i.e. worst case) ground faults occur. Under fault conditions, the following factors determine step and touch potentials:

- Magnitude of the fault current
- Resistance of ground combined with the ground grid consisting of station electrodes, transmission line sky wires and distribution neutrals
- Ground resistivity of upper and lower layers of earth.

Increases in system capacity and fault currents at a station may lead to unacceptable performance of the ground grid. Corrosion of buried conductors and connectors, mechanical damage to buried electrodes, plus burning-off of grounding conductors and connectors during heavy fault currents also may lead to unsatisfactory performance. Further, changes in resistivity of upper or lower layers of earth may adversely affect ground grid characteristics.

31.2 System Hierarchy

Grounding systems used in both the Transmission and Municipal Station systems.

31.3 Useful Life and Typical Life

Station grounding systems have a useful life range of 25 to 50 years; the typical life is 40 years [11][21][22].

32 Station Grounding Transformer

Electrical distribution systems can be configured as a grounded or ungrounded system. A grounded system has an electrical connection between source and the earth, whereas an ungrounded system has no intentional connection. Sometimes it is necessary to create a ground on an ungrounded system for safety or to aid in protective relaying applications. Grounding transformers, smaller transformers similar in construction to power transformers, are used in this application.

32.1 Degradation Mechanism

Like a majority of transformers, the end of life for this asset is a result of insulation degradation, more specifically, the failure of pressboard and paper insulation. Degradation of the insulating oil, and more significantly, paper insulation, typically results in end of life. Insulation degradation is a result of oxidation, a process that occurs in the presence of oxygen, high temperature, and moisture. For oil cooled transformers, particles, acids, and static electricity will also deteriorate the insulation.

32.2 System Hierarchy

Grounding transformers used in both the Transmission and Municipal Station systems.

32.3 Useful Life and Typical Life

Station grounding transformers have a typical life range of 30 to 40 years; the typical life of this asset is 40 years [23][24].

32.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset class is three years.

33 SCADA RTU

Supervisory Control and Data Acquisition (SCADA) refers to the centralized monitoring and control system of a facility. SCADA remote terminal units (RTUs) allow the master SCADA system to communication, often wirelessly, with field equipment. In general, RTUs collect digital and analog data from equipment, exchange information to the master system, and perform control functions on field devices. They are typically comprised of the following: power supply, CPU, I/O Modules, housing and chassis, communications interface, and software.

33.1 Degradation Mechanism

There are many factors that contribute to the end-of-life of RTUs. Utilities may choose to upgrade or replace older units that are no longer supported by vendors or where spare parts are no longer available. Because RTUs are essentially computer devices, they are prone to obsolescence. For example, older units may lack the ability to interface with Intelligent Electronic Devices (IEDs), be unable to support newer or modern communications media and/or protocols, or not allow for the quantity, resolution, and accuracy of modern data acquisition. Legacy units may have limited ability of multiple master communication ports and protocols, or have an inability to segregate data into multiple RTU addresses based on priority.

33.2 System Hierarchy

SCADA RTUs are used in both the Transmission and Municipal Station systems.

33.3 Useful Life and Typical Life

The useful life range of SCADA RTU is 15 to 30 years; the typical life is 20 years [26][27].

34 Automatic Transfer Switch (ATS)

Automatic Transfer Switches (ATSs) are designed to operate in several different configurations and controls can be generally configured to suit different operating scenarios. Open transition transfer switches are the simplest kind. They are mechanically interlocked to ensure that the power from one source is disconnected before the connection is made to the other source. The closed transition transfer switches eliminate momentary power interruption when both sources are present and synchronized, by transferring the loads with an overlapping contact arrangement. The soft load closed transition switch extends the overlap time to multiple seconds, for a smoother transition of load to the standby source.

The transfer switches are generally electrically operated and mechanically held and have auxiliary contacts for control circuits. Main contacts are commonly made of silver alloy to resist welding and sticking during load transfers. They are mounted either in ventilated or submersible enclosures depending on the installation location. Just like circuit breakers, the heavy duty switches are often equipped with arc chutes to extinguish switching arcs.

34.1 Degradation Mechanism

The health degradations the transfer switch is subjected to include:

- contact wear
- wear and tear of the mechanical operating mechanism
- degradation of insulator supports and inter-phase barriers
- corrosion of the switch tank
- failure of the tanks seals allowing penetration of the moisture

Since the primary purpose of transfer switches is to ensure high reliability for critical loads, it is imperative that any interruptions due to the failure of the switch itself be avoided.

34.2 System Hierarchy

THESL uses Automatic Transfer Switches in the Underground system.

34.3 Useful Life and Typical Life

The useful life range of ATS is 30 to 50 years; the typical life is 45 years [2][23].

34.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset class is 3 years.

35 Network Transformer

Network transformers are special purpose distribution transformers, designed and constructed for successful operation in a parallel mode with a large number of transformers of similar characteristic. The spot network transformers can range in nameplate rating from 500 kVA to 1500 kVA. The primary winding of the transformers is connected in Delta configuration while the secondary is in grounded star configuration. The network transformers are provided with a primary disconnect, which has no current interrupting rating and is used merely as in isolating device after the transformer has been de-energized both from primary and secondary source. The secondary bushings are mounted on the side wall of the transformer in a throat, suitable for mounting of the network protector.

Network protectors are special purpose low voltage air circuit breakers, designed for successful parallel operation of network transformers. Network protectors are fully self contained units, equipped with protective relays and instrument transformers to allow automatic closing and opening of the protector. The relays conduct a line test before initiating close command and allow closing of the breaker only if the associated transformer has the correct voltage condition in relation to the grid to permit flow of power from the transformer to the grid. If the conditions are not right, protector closing is blocked. The protector is also equipped with a reverse current relay that trips if the power flow reverses from its normal direction, i.e. if the power flows from grid into the transformer.

35.1 Degradation Mechanism

Since in a majority of the applications transformers are installed in below grade vaults, the transformer is designed for partially submersible operation with additional protection against corrosion. While network transformers are available in dry-type (cast coil and epoxy impregnation) designs, a vast majority of the network transformers employ mineral oil for insulation and cooling. The network transformer has a similar degradation mechanism to other distribution transformers.

The life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

The breaker design in network protectors employs mechanical linkages, rollers, springs and cams for operation which require periodic maintenance. All network protectors are equipped with special load-side fuses, mounted either internally or external to the network protector housing. The fuses are intended to allow normal load current and overloads while providing backup protection in the event that the protector fails to open on reverse fault current (due to faults internal to the protector or near transformer low voltage terminals). Every time arcing occurs in open air within the network protector housing, whether due to operation of the air breaker or because of fuse blowing (except silver sand), a certain amount of metal vapour is liberated and dispersed over insulating parts. Fuses evidently liberate more vapour than breaker operation. Over time, this buildup reduces the dielectric strength of insulating barriers. Eventually this may result in a breakdown, unless care is taken to clean the network protector internally, particularly after fuse operations. THESL typically replaces protectors with new or refurbished protectors if the backup fuses have been found to have operated.

Various parameters that impact the health and condition and eventually lead to end of life of a network include condition of mechanical moving parts, condition of inter phase barriers, number of protector operations (counter reading), accumulation of dirt or debris in protector housing, corrosion of protector housing, condition of fuses, condition of arc chutes and time period elapsed since last major overhaul of the protector.

The health of network protector is established by taking into account the following factors:

- Number of operations since last overhaul
- Operating age of protector
- Condition of operating mechanism
- Condition of fuses
- Condition of arc chutes
- Condition of protector relays
- Condition of gaskets and seals for submersible units

35.2 System Hierarchy

THESL uses network transformers and protectors in the Underground system.

35.3 Useful Life and Typical Life

This asset class can be componentized into the following:

- Network Transformer
- Network Protector

35.3.1 Network Transformer

The useful life range of the transformer is 20 to 50 years; typical life is 35 years [2][23].

35.3.2 Network Protector

The useful life range of the protector is 20 to 40 years; typical life is 35 years [2][23].

35.4 Time Based Maintenance Intervals

The typical routine inspection schedule for both the transformer and protector components is every two years.

36 Pad Mounted Transformer

Pad mounted transformers are amongst the distribution transformers employed by THESL, with the transformer being single phase, 100 kVA, 16 kV. These transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid.

36.1 Degradation Mechanism

The pad-mounted transformer has a similar degradation mechanism to other distribution transformers. It has been demonstrated that the life of the transformer's internal insulation is related to temperature rise and duration. Therefore, the transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage current surges also have strong effects. Therefore, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

In general, the following are considered when determining the health of the pad-mounted transformer:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs, etc.
- Transfer operating age and winding temperature profile

36.2 System Hierarchy

Pad mounted transformers are used in the Underground system.

36.3 Useful Life and Typical Life

Pad mounted transformers have a useful life range of 30 to 40 years; the typical life is 40 years [23][24].

37 Vault Transformer

Vault transformers are amongst the distribution transformers employed by THESL, with the typical transformer being single phase, 100 kVA, 16 kV. These transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid.

37.1 Degradation Mechanism

The vault transformer has a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges have strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

37.2 System Hierarchy

Vault transformers are used in the Underground system.

37.3 Useful Life and Typical Life

Vault transformers have a useful life range of 30 to 40 years; the typical life is 40 years [23][24].

37.4 Time Based Maintenance Intervals

The typical routine inspection schedule for this asset is every two years.

38 Submersible Transformer

Submersible transformers are amongst the distribution transformers employed by THESL, with the typical transformer being single phase, 100 kVA, 16 kV. These transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid.

38.1 Degradation Mechanism

The submersible transformer has a similar degradation mechanism to other distribution transformers. The life of the transformer's internal insulation is related to temperature rise and duration, so transformer life is affected by electrical loading profiles and length of service life. Mechanical damage, exposure to corrosive salts, and voltage current surges have strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

38.2 System Hierarchy

Submersible transformers are used in the Underground system.

38.3 Useful Life and Typical Life

Submersible transformers have a useful life range of 25 to 40 years; the typical life is 35 years [23][24].

38.4 Time Based Maintenance Intervals

The typical routine inspection schedule for this asset is every two years.

39 Network Vault

Equipment vaults permit installation of transformers, switchgear or other equipment. Utility vaults are often constructed out of reinforced or un-reinforced concrete. Vaults used for transformer installation are often equipped with ventilation grates to provide natural or forced cooling. The typical network vault size used by THESL is 2.3m W x 6.4m L x 3.4m H.

39.1 Degradation Mechanism

Vaults should be capable of bearing the loads that are applied on them. As such, mechanical strength is a basic end of life parameter for a vault. Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect. Degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies. Similarly, units with lights that do not function properly constitute defective systems.

39.2 System Hierarchy

Network vaults are used in the Underground system.

39.3 Useful Life and Typical Life

The overall useful life range of network vaults is 40 to 80 years; the typical life is 60 years [1][23][27].

A major component of this asset is the roof, as this component is typically rebuilt one to two times during the life of the vault.

39.3.1 Roof

The roof has a useful life range of 20 to 30 years, with a typical life of 25 years.

39.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

40 Radial Vault

As with other types of underground vaults, radial vaults allow for the underground installation of equipment. The typical radial vault size used by THESL is 3.0m W x 8.5m L x 3.66m H.

40.1 Degradation Mechanism

For radial vaults, as with network vaults and other underground civil structures, mechanical strength is an end of life parameter. Age, mechanical loading, and exposure to corrosive are factors. Degradation includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers. Exposure to acidic salts affects corrosion rates. Improperly functioning sump pumps or lights also constitute defective systems.

40.2 System Hierarchy

Radial vaults are used in the Underground system.

40.3 Useful Life and Typical Life

The useful life range of radial vaults is 40 to 80 years; the typical life is 60 years [1][23][27].

A major component of this asset is the roof, as this component is typically rebuilt one to two times during the life of the vault.

40.3.1 Roof

The roof has a useful life range of 20 to 30 years, with a typical life of 25 years.

40.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

41 Underground Residential Distribution (URD) Vault

As with other types of underground vaults, URD vaults allow for the underground installation of equipment. The typical URD vault size used by THESL is 1.5m W x 3.5m L x 2.1m H.

41.1 Degradation Mechanism

For URD vaults, as with other underground civil structures, mechanical strength is an end of life parameter. Age, mechanical loading, and exposure to corrosive are factors. Degradation includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers. Exposure to acidic salts affects corrosion rates. Improperly functioning sump pumps or lights also constitute defective systems.

41.2 System Hierarchy

URD vaults are used in the Underground system.

41.3 Useful Life and Typical Life

The useful life range of this asset class is 40 to 80 years; the average life is 60 years [1][23][27].

A major component of this asset is the roof, as this component is typically rebuilt one to two times during the life of the vault.

41.3.1 Roof

The roof has a useful life range of 20 to 30 years, with a typical life of 25 years.

41.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

42 Submersible Vault

As with other types of underground vaults, submersible vaults allow for the underground installation of equipment. The typical submersible vault size used by THESL is 1.24m W x 2.26m L x 1.98m H.

42.1 Degradation Mechanism

For submersible vaults, as with other underground civil structures, mechanical strength is an end of life parameter. Age, mechanical loading, and exposure to corrosive are factors. Degradation includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers. Exposure to acidic salts affects corrosion rates. Improperly functioning sump pumps or lights also constitute defective systems.

42.2 System Hierarchy

Submersible vaults are used in the Underground system.

42.3 Useful Life and Typical Life

The useful life range of this asset class is 40 to 80 years; the average life is 60 years [1][23][27].

A major component of this asset is the roof, as this component is typically rebuilt one to two times during the life of the vault.

42.3.1 Roof

The roof has a useful life range of 20 to 30 years, with a typical life of 25 years.

42.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

43 Cable Chamber

Cable Chambers facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance. They come in different styles, shapes and sizes according to the location and application. Pre-cast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are less expensive to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a more benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems.

43.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, utility chambers must withstand heavy loads associated with traffic in the street. When located in driving lanes, cable chamber chimney and collar rings must match street grading. Since utility chambers and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping of utility chambers into sewer systems, without testing of the water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have stronger effects. Cable chamber degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Cable chamber systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a cable chamber system. Similarly, cable chamber systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with cable chambers also requires evaluation in assessing the overall condition of a cable chamber system.

43.2 System Hierarchy

Cable chambers are used in the Underground system.

43.3 Useful Life and Typical Life

Cable chambers have a useful life range of 50 to 80 years; the typical life range is 60 years [2][23][28].

A major component of this asset is the roof, as this component is typically rebuilt one to two times during the life of the vault.

43.3.1 Roof

The roof has a useful life range of 20 to 30 years, with a typical life of 25 years.

43.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is three years.

44 Duct Bank

In areas such as road crossings, duct banks provide a conduit for underground cables to travel. They are comprised of a number of ducts, in trench, and typically encased in concrete. Ducts are sized as required and are usually four, five or six inches in diameter. The typical duct bank installation by THESL is 3 W x 2 H.

44.1 Degradation Mechanism

The ducts connecting one cable chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a cable chamber that is otherwise in sound condition is a good indicator of a failure of a portion of the ductwork. Since there are no specific tests that can be conducted to determine duct integrity at reasonable cost, the duct system is typically treated on an ad hoc basis and repaired or replaced as is determined at the time of cable replacement or failure.

44.2 System Hierarchy

Duct banks are used in the Underground system.

44.3 Useful Life and Typical Life

Duct banks have a typical useful life of 30 to 80 years; the average life is 50 years [2][23].

45 Padmounted Switchgear (SF6/Vacuum)

Pad-mounted switchgear are used for protection and switching in the underground distribution system. The switching assemblies can be classified into SF6 load break switches and vacuum fault interrupters.

45.1 Degradation Mechanism

The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures or ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism and degradation of insulated barriers.

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO_2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, pad-mounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

45.2 System Hierarchy

Pad-mounted switchgear are used in the Underground system.

45.3 Useful Life and Typical Life

The useful life range of this asset class is 30 to 50 years; the typical life is 30 years [31].

45.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is three years.

46 Padmounted Switchgear (Air Insulated)

Pad-mounted switchgear are used for protection and switching in the underground distribution system. The switching assemblies can be air insulated. A majority of the pad mounted switchgear currently employs air-insulated gang operated load-break switches.

46.1 Degradation Mechanism

The degradation of the air insulated padmounted switchgear is similar to that of the SF6 switchgear. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

46.2 System Hierarchy

Pad-mounted switchgear are used in the Underground system.

46.3 Useful Life and Typical Life

The useful life range of this asset class is 20 to 40 years; typical life is 20 years [30][29].

46.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is 3 years.

47 SF6/Vacuum Underground Switches

The underground SF6/Vacuum switches used by THESL are Loadbreak, Vacuum, 3PH, 15KV, 200AMP, 2-WAY 1-SWITCHED (Kearney Part Number 21VP95-22) or 3-WAY 3-SWITCHED (Kearney Part Number 33VP95-222). These units are essentially pad mounted switchgear, enclosed in stainless steel containers, with the ability to be wall or ceiling mounted.

47.1 Degradation Mechanism

The degradation mechanism of this asset is similar to that of other types of padmounted switchgear. Aging and end of life is established by mechanical failures, such as corrosion of operating mechanism from rusting of enclosure or moisture and dirt ingress. Switchgear failure is associated more with outside influences rather than age. For example, switchgear failure is more likely to be caused by rodents, dirt or contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching.

47.2 System Hierarchy

SF6/Vacuum Underground switches are used in the Underground system.

47.3 Useful Life and Typical Life

The useful life range of this asset class is 30 to 50 years; the typical life is 30 years [31].

47.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is 3 years.

48 Underground Primary Cable (XLPE in Duct)

Distribution underground cables are mainly used in urban areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental and safety reasons. The initial capital cost of a distribution underground cable circuit is three or more times the cost of an overhead line of equivalent capacity and voltage. The cross linked polyethylene (XLPE) cable in duct is amongst the types of underground distribution cables used by THESL.

48.1 Degradation Mechanism

Over the past 30 years XLPE insulated cables have all but replaced paper-insulated cables. These cables can be manufactured by a simple extrusion of the insulation over the conductor and therefore are much more economic to produce. In normal cable lifetime terms XLPE cables are still relatively young. Therefore, failures that have occurred can be classified as early life failures. Certainly in the early days of polymeric insulated cables their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced in the manufacturing process. Over the past 30 years many of these problems have been addressed and modern XLPE cables and accessories are generally very reliable.

Polymeric insulation is very sensitive to discharge activity. It is therefore very important that the cable, joints and accessories are discharge free when installed. Discharge testing is, therefore, an important factor for these cables. This type of testing is conducted during commissioning and is not typically used for detection of deterioration of the insulation. These commissioning tests are an area of some concern for polymeric cables because the tests themselves are suspected of causing permanent damage and reducing the life of polymeric cables.

Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination, voids or discontinuities will accelerate degradation. This is assumed to be the reason for poor reliability and relatively short lifetimes of early polymeric cables. As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved.

48.2 System Hierarchy

Underground cables are used in the Underground system.

48.3 Useful Life and Typical Life

The useful life range of this asset class is 40 to 60 years; typical life is 40 years [9][2].

49 Underground Primary Cable (XLPE Direct Buried)

While cross linked polyethylene (XLPE) underground cable can be installed in ducts, it can also be directly buried.

49.1 Degradation Mechanism

The degradation of the directly buried cable is similar to that of the XLPE cable in duct. Polymeric insulation is sensitive to discharge activities. Water treeing is a significant deterioration process, and the degree is a factor of contamination and quality of polymeric insulation.

49.2 System Hierarchy

Underground cables are used in the Underground system.

49.3 Useful Life and Typical Life

The useful life range of this asset class is 20 to 25 years; typical life is 25 years [32][2].

50 Underground Primary Cable (PILC)

The Paper Insulated Lead Covered (PILC) cable is amongst the types of underground distribution cables used by THESL.

50.1 Degradation Mechanism

For PILC cables, the two significant long-term degradation processes are corrosion of the lead sheath and dielectric degradation of the oil impregnated paper insulation. Isolated sites of corrosion resulting in moisture penetration or isolated sites of dielectric deterioration resulting in insulation breakdown can result in localized failures. However, if either of these conditions becomes widespread there will be frequent cable failures and the cable can be deemed to be at effective end-of-life.

As discussed above, condition information relating to either of these degradation processes is very difficult to obtain. Generally, the only opportunity to obtain useful condition information is at the time of a failure and repair. Examination and analysis of faulted sections can therefore be an important condition assessment process. Firstly, it is essential to discriminate between condition related and non-condition related cable failures. Third party damage is a major cause of failure, either immediately following damage or a failure that occurs subsequently as the result of earlier damage. Clearly, if frequency of failures is to be used as a measure to determine end-of-life it is important that only condition based failures are included. Systematic analysis and assessment of condition of cables associated with failure positions can, over a period of time, build up, a useful picture of the condition of the cable network.

50.2 System Hierarchy

Underground cables are used in the Underground system.

50.3 Useful Life and Typical Life

The useful life range of this asset class is 70 to 80 years; the typical life is 75 years [32][33].

51 Underground Secondary (In Duct)

Secondary underground cables are used as feeders to residential premises. The typical cable used by THESL is Cable 500 kcmil Cu XLPE 600V.

51.1 Degradation Mechanism

Underground secondary conductors are typically insulated with XLPE. The degradation process is similar to that of primary XLPE cables. Polymeric insulation is sensitive to discharge activities. Water treeing is a significant deterioration process, and the degree is a factor of contamination and quality of polymeric insulation.

51.2 System Hierarchy

Underground cables are used in the Underground system.

51.3 Useful Life and Typical Life

The useful life range of this asset class is 40 to 60 years; the typical life is 40 years [9][2].

52 Underground Secondary (DB)

While secondary underground cables can be buried in duct, they can also be direct buried. The typical secondary cable used by THESL is Cable 500 kcmil Cu XLPE 600V.

52.1 Degradation Mechanism

Underground secondary conductors are typically insulated with XLPE. The degradation process is similar to that of primary XLPE cables. Polymeric insulation is sensitive to discharge activities. Water treeing is a significant deterioration process, and the degree is a factor of contamination and quality of polymeric insulation.

52.2 System Hierarchy

Underground cables are used in the Underground system.

52.3 Useful Life and Typical Life

The useful life range of this asset class is 20 to 25 years; the typical life is 25 years [32][2].

53 Lighting Assemblies (Conventional)

Conventional streetlights powered by underground cabling are used illuminate streets and roadways. The major components of conventional street lighting are poles, luminaires, cabling, and civil components (i.e. duct, handwell).

53.1 Degradation Mechanism

The poles used for street lighting are commonly made of steel, aluminum, or concrete. The typical pole materials used by THESL are aluminum and concrete. Environmental stresses contribute to the corrosion of aluminum poles. Luminaires used in street lighting may be prone to corrosion. In addition, continuous exposure of polycarbonate optics to ultraviolet light can result in diminished light level output.

53.2 System Hierarchy

Streetlights fed by underground cables are used in the Underground system.

53.3 Useful Life and Typical Life

Conventional lighting assemblies can be componentized into the following:

- Cabling
- Civil (duct, handwell)
- Pole (aluminum)
- Luminaire

53.3.1 Cabling

The useful life range of streetlight cabling is 40-60 years; typical life is 40 years [32][2].

53.3.2 Civil (Handwell, Tap Box)

The useful life range of the civil components is 50-60 years; typical life is 50 years [23].

53.3.3 Poles

The useful life range of the poles is 40-60 years; the typical life is 50 years [35].

53.3.4 Luminaire

The useful life range of the luminaire is 20-30 years; the typical life is 25 years [10].

53.4 Time Based Maintenance Intervals

The routine inspection interval for this asset is four years.

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TAXES AND PILS

Previously filed as Exhibit H1, Tab 1, Schedule 1, Table 1

Table 1: Summary of PILs by Year ($ millions)

	2005 Historical	2006 Historical	2007 Historical	2008 Historical	2009 Historical	2010 Bridge	2011 Test	2011 Accounting Update
Income Taxes	56.9	52.6	46.7	29.8	19.4	26.5	28.1	14.6
Capital tax	5.8	6.6	5.2	5.4	5.5	2.1	-	-
Total PILs	62.7	59.2	51.9	35.2	24.9	28.6	28.1	14.6

2011 PILS / CORPORATE TAX FILING

Sheet Index:

Notes

Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility: Toronto Hydro-Electric System Limited

Licence Number: ED-2002-0497

File Number: RP-XXXX-XXXX

EB-2010-0142

SUMMARY SHEET

Name of Utility: **Toronto Hydro-Electric System Limited**
Licence Number: **ED-2002-0497**
File Numbers: **RP-XXXX-XXXX, EB-2010-0142**

Ratebase	2,360,526,818	3-1 DATA for PILS MODEL	D 15
Net Income Before Taxes	93,004,757	3-1 DATA for PILS MODEL	E 19
Calculation of Deemed Interest			
Debt Ratio	60.00%	3-1 DATA for PILS MODEL	D 16
Debt Rate % (as calculated)	5.15%	3-1 DATA for PILS MODEL	D 17
Deemed Interest to be recovered	72,940,279		

<u>Questions that must be answered</u>	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	Yes
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	Yes
2. Does the applicant have any Investment Tax Credits (ITC)?	Yes
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	Yes
4. Does the applicant have any Capital Gains or Losses for tax purposes?	Yes
5. Does the applicant have any Capital Leases?	Yes
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2010 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	No
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2010 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2010 and/or prior years?	No

Tax Rates & Exemptions

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Applicant	Rate Base	OCT Exemption
		15,000,000
Toronto Hydro-Electric System Limited	2,360,526,818	15,000,000
Regulated Affiliates (if applicable)		
1.		0
2.		0
3.		0
4.		0
5.		0
Total	2,360,526,818	15,000,000

Corporate Tax Rates for Test Year

Income Range	0 to 500,000	500,000 to 1,500,000	>1,500,000
Federal			16.50%
Ontario			11.75%
Income Tax Rates used to gross up the true up variance			28.25%
Ontario SBD Clawback			

Capital Tax Rate	0.000%
Surtax	0.00%

Test Year Schedule 8 and 10 UCC and CEC

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Methodology: This schedule starts with projected 2009 Schedules 8 and 10; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	Projected UCC End of Year Dec 31/10 Per 2010 Sch. 8 & 10	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System not in Cl. 47 - post 1987	1,158,255,094	0	0	1,158,255,094
2	Distribution System - pre 1988	372,889,008	0	0	372,889,008
8	General Office/Stores Equip	31,532,728	0	0	31,532,728
10	Computer Hardware/ Vehicles	24,939,093	0	0	24,939,093
10.1	Certain Automobiles	4,628	0	0	4,628
12	Computer Software	17,043,427	0	0	17,043,427
13 1	Lease # 1	118,715	0	0	118,715
13 2	Lease #2	3,021,653	0	0	3,021,653
13 3	Lease # 3	878,182	0	0	878,182
13 4	Lease # 4	148,025	0	0	148,025
13 5	Lease # 5	519,016			519,016
14	Franchise	0	0	0	0

17	**New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs**	12,856,400	0	0	12,856,400
42	**Fibre Optic Cable**	54,895	0	0	54,895
43.1	**Certain Energy-Efficient Electrical Generating Equipment**	0	0	0	0
45	**Computers & Systems Software acq'd post Mar 22/04**	490,806	0	0	490,806
46	**Data Network Infrastructure Equipment (acq'd post Mar 22/04)**	0	0	0	0
47	**Distribution Equipment (acq'd post Feb 22/05)**	837,439,839	0	0	837,439,839
50	**Computer Software acquired after March 18, 2007**	1,029,150			1,029,150
52	**Computer hardware acquired after January 2009 and before February 2011**	0			0
98	**WIP**	148,394,419	0	0	148,394,419
0	0	0	0	0	0
	SUB-TOTAL - UCC	**2,609,615,078**	**0**	**0**	**2,609,615,078**
CEC	**Goodwill**	0	0	0	0
CEC	**Land Rights**	0	0	0	0
CEC	**FMV Bump-up**	0	0	0	0
CEC	**Total**	12,618,923	0	0	12,618,923
0	0	0	0	0	
	SUB-TOTAL - CEC	**12,618,923**	**0**	**0**	**12,618,923**

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Total Capital Assets for PILs Model		CCA Class	2011 Projected Capital Transactions		2011 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	1	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0
1745	Roads and Trails	1	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0
1908	Buildings and Fixtures	1	18,070,086		18,070,086	0
2010	Electric Plant Purchased or Sold	1	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0
SUBTOTAL - CLASS 1			**18,070,086**	**0**	**18,070,086**	**0**
1620	Buildings and Fixtures	2	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0
1715	Station Equipment	2	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0
1735	Underground Conduit	2	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0
1745	Roads and Trails	2	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0
1840	Underground Conduit	2	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Total Capital Assets for PILs Model		CCA Class	2011 Projected Capital Transactions		2011 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1845	Underground Conductors and Devices	2	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Total Capital Assets for PILs Model		CCA Class	2011 Projected Capital Transactions		2011 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
1850	Line Transformers	2	0	0	0	0
1855	Services	2	0	0	0	0
1860	Meters	2	0	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**
1875	Street Lighting and Signal Systems	8	0	0	0	0
1915	Office Furniture and Equipment	8	1,645,363	0	1,645,363	0
1935	Stores Equipment	8		0	0	0
1940	Tools, Shop and Garage Equipment	8	1,918,615	0	1,918,615	0
1945	Measurement and Testing Equipment	8	89,422	0	89,422	0
1950	Power Operated Equipment	8		0	0	0
1955	Communication Equipment	8		0	0	0
1960	Miscellaneous Equipment	8	24,802	0	24,802	0
1965	Water Heater Rental Units	8		0	0	0
1970	Load Management Controls - Customer Premises	8		0	0	0
1975	Load Management Controls - Utility Premises	8		0	0	0
1980	System Supervisory Equipment	8	2,144,960	0	2,144,960	0
1985	Sentinel Lighting Rental Units	8		0	0	0
1990	Other Tangible Property	8	0	0	0	0
SUBTOTAL - CLASS 8			**5,823,163**	**0**	**5,823,163**	**0**
	Fibre Optic Cable	42	0	0	0	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Total Capital Assets for PILs Model		CCA Class	2011 Projected Capital Transactions		2011 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
SUBTOTAL - CLASS 42			0	0	0	0
1920	Computer Equipment - Hardware	50	8,416,574	0	8,416,574	0
1925	Computer Software - CL50	50	11,553,186	0	11,553,186	0
SUBTOTAL - CLASS 50			19,969,760	0	19,969,760	0
1920	Computer Equipment - Hardware	52	611,978	0	611,978	0
1925	Computer Software - CL52	52	1,050,290	0	1,050,290	0
SUBTOTAL - CLASS 52			1,662,268	0	1,662,268	0
1930	Transportation Equipment	10	13,971,879		13,971,879	0
SUBTOTAL - CLASS 10			13,971,879	0	13,971,879	0
1925	Computer Software - CL12	12	20,563,565	0	20,563,565	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Total Capital Assets for PILs Model		CCA Class	2011 Projected Capital Transactions		2011 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
SUBTOTAL - CLASS 12			**20,563,565**	**0**	**20,563,565**	**0**
1630	Leasehold Improvements	13 1		0	0	0
1710	Leasehold Improvements	13 2	0	0	0	0
1810	Leasehold Improvements	13 3	0	0	0	0
1910	Leasehold Improvements	13 4				
2010	Leasehold Improvements	13 5				
2110	Leasehold Improvements	13 6	542,813	0	542,813	0
SUBTOTAL - CLASS 13			**542,813**	**0**	**542,813**	**0**
	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	17	549,396		549,396	0
SUBTOTAL - CLASS 17			**549,396**	**0**	**549,396**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0
1675	Generators	43.1	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**	**0**
	Station Equipment	47	0	0	0	0
	Towers and Fixtures	47	0	0	0	0
	Poles and Fixtures	47		0	0	0
	Overhead Conductors and Devices	47		0	0	0
	Underground Conduit	47		0	0	0
	Underground Conductors and Devices	47		0	0	0
	Transformer Station Equipment - Normally Primary above 50 kV	47	7,194,438	0	7,194,438	0
	Distribution Station Equipment - Normally Primary below 50 kV	47	11,186,750	0	11,186,750	0
	Storage Battery Equipment	47		0	0	0
	Poles, Towers and Fixtures	47	19,757,932	0	19,757,932	0
	Overhead Conductors and Devices	47	18,443,950	0	18,443,950	0
	Underground Conduit	47	84,926,953	0	84,926,953	0
	Underground Conductors and Devices	47	77,918,998	0	77,918,998	0
	Line Transformers	47	30,023,272	0	30,023,272	0
	Services	47	7,352,067	0	7,352,067	0

UCC Additions and CEC Additions

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Total Capital Assets for PILs Model		CCA Class	2011 Projected Capital Transactions		2011 Projected Capital Transactions	
			Additions	Disposals	Additions	Disposals
	Meters	47	24,543,142	0	24,543,142	0
1970	Load Mangement Controls	47	-85,701	0	-85,701	0
	Leased Property on Customer Premises	47		0	0	0
	Fixed Assets for Conservation and Demand Management	47		0	0	0
	Smart Meters	47		0	0	0
1995	Contributions and Grants - Credit	47		0	0	0
SUBTOTAL - CLASS 47			**281,261,801**	**0**	**281,261,801**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0
2075	Non-Utility Property Owned or Under Capital	CL	0	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP		0	0	0
1616	Land Rights	ECP		0	0	0
1706	Land Rights	ECP		0	0	0
1806	Land Rights	ECP		0	0	0
1906	Land Rights	ECP		0	0	0
2060	Electric Plant Acquisition Adjustment	ECP		0	0	0
2065	Other Electric Plant Adjustment	ECP	16,279,959	0	16,279,959	0
1608	Franchises and Consents	14	0	0	0	0
SUBTOTAL - Eligible Capital Property			**16,279,959**	**0**	**16,279,959**	**0**
1615	Land	LAND	0		0	0
1705	Land	LAND	0	0	0	0
1805	Land	LAND	0	0	0	0
1905	Land	LAND	0	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0
			0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**378,694,690**	**0**	**378,694,690**	**0**

Schedule 8 CCA Test Year

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	2011 Projected Additions	2011 Projected Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System not in Cl. 47 - post 1987	1,158,255,094	18,070,086	0	1,176,325,180	9,035,043	1,167,290,137	4%	46,691,605	1,129,633,575
2	Distribution System - pre 1988	372,889,008	0	0	372,889,008	0	372,889,008	6%	22,373,340	350,515,668
8	General Office/Stores Equip	31,532,728	5,823,163	0	37,355,891	2,911,581	34,444,309	20%	6,888,862	30,467,029
10	Computer Hardware/ Vehicles	24,939,093	13,971,879	0	38,910,972	6,985,940	31,925,033	30%	9,577,510	29,333,462
10.1	Certain Automobiles	4,628	0	0	4,628	0	4,628	30%	1,388	3,240
12	Computer Software	17,043,427	20,563,565	0	37,606,992	10,281,783	27,325,210	100%	27,325,210	10,281,783
13_1	Leasehold Improvement # 1	118,715	0	0	118,715	0	118,715	SL	118,714	1
13_2	Leasehold Improvement # 2	3,021,653	0	0	3,021,653	0	3,021,653	SL	2,014,435	1,007,218
13_3	Leasehold Improvement # 3	878,182	0	0	878,182	0	878,182	SL	351,273	526,909
13_4	Leasehold Improvement # 4	148,025	0	0	148,025	0	148,025	SL	42,293	105,732
13_5	Leasehold Improvement # 5	519,016			519,016	0	519,016	SL	115,337	403,679
13_6	Leasehold Improvement # 6		542,813		542,813	271,407	271,407	SL	54,281	488,532
14	Franchise	0	0	0	0	0	0		0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	12,856,400	549,396	0	13,405,796	274,698	13,131,098	8%	1,050,488	12,355,308
42	Fibre Optic Cable	54,895	0	0	54,895	0	54,895	12%	6,587	48,308
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	490,806	0	0	490,806	0	490,806	45%	220,863	269,943
50	Computer Software acquired after March 18, 2007	1,029,150	19,969,760		20,998,910	9,984,880	11,014,030	55%	6,057,717	14,941,194

Schedule 8 CCA Test Year

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
47	Distribution Equipment (acq'd post Feb 22/05)	837,439,839	281,261,801	0	1,118,701,640	140,630,901	978,070,740	8%	78,245,659	1,040,455,981
52	Computer hardware acquired after January 2009 and before February 2011	0	1,662,268	0	1,662,268	0	1,662,268	100%	1,662,268	0
98	WIP	148,394,419	0	0	148,394,419	0	148,394,419		0	148,394,419
0	0	0	0	0	0	0	0		0	0
		0							0	0
		0							0	0
	TOTAL	2,609,615,078	362,414,732	0	2,972,029,810	180,376,232	2,791,653,578		202,797,831	2,769,231,979

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility:
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Cumulative Eligible Capital				12,618,923
Additions				
Cost of Eligible Capital Property Acquired during Test Year	16,279,959			
Other Adjustments	0			
Subtotal	16,279,959	x 3/4 =	12,209,969	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0	
			12,209,969	12,209,969
Amount transferred on amalgamation or wind-up of subsidiary	0			0
Subtotal				24,828,892
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	x 3/4 =	0	0
Cumulative Eligible Capital Balance				24,828,892
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		24,828,892	x 7% =	1,738,022
Cumulative Eligible Capital - Closing Balance				23,090,870

Ontario

Schedule 13 – Tax Reserves

Name of Utility:
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2009	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2009 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2009 Adjusted Utility Balance	Test Year Adjustments Add (+)	Test Year Adjustments Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)	480,500		480,500		480,500	0		480,500	0	
General reserve for bad debts	0		0		0			0	0	
Accrued Employee Future Benefits:	163,841,000		163,841,000		163,841,000	8,121,000		171,962,000	8,121,000	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	

Schedule 13 – Tax Reserves

Name of Utility:
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

CONTINUITY OF RESERVES

Description	Projected Balance at December 31, 2009	Non-Distribution Eliminations Sign Convention: Increase (+) Decrease (-)	2009 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2009 Adjusted Utility Balance	Test Year Adjustments Add (+)	Test Year Adjustments Deduct (-)	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
- Termination Cost	1,500,000		1,500,000		1,500,000			1,500,000	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**165,821,500**	**0**	**165,821,500**	**0**	**165,821,500**	**8,121,000**	**0**	**173,942,500**	**8,121,000**	**0**

Excess Interest Expense

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

Calculated Deemed Interest Expense in 2011 EDR model	72,940,279	
2011 Actual Interest Expense	73,330,904	2-2 UNADJUSTED ACCOUNTING DATA L 491
2011 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA L 431
2011 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA L 432
2011 Actual Interest	73,330,904	
Interest Forecast for Tier 1 or 2 Adjustments		
Total Interest	73,330,904	
Excess Interest Expense for 2011 PILs	390,625	

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		93,004,757
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	145,151,913
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	
Tax reserves beginning of year	125	
Reserves from financial statements- balance at end of year	126	173,942,500
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

	T2 S1 line #	Test Year Taxable Income
Development expenses claimed in current year	212	
Financing fees deducted in books	216	701,385
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
See Attached	295	14,690,074
	296	
	297	
Total Additions		**334,485,872**

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

	T2 S1 line #	Test Year Taxable Income
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	202,797,831
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	1,738,022
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves end of year	413	0
Reserves from financial statements - balance at beginning of year	414	165,821,500
Contributions to deferred income plans	416	
Book income of joint venture or partnership	305	
Equity in income from subsidiary or affiliates	306	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Financing Fees for Tax Under S.20(1)(e) / S.20(1)(e.1)	393	1,038,003
See Attached	394	14,980,504
Excess Interest (from Tab "Schedule 7-3")	395	390,625
	396	
	397	
Total Deductions		**386,766,485**
NET INCOME FOR TAX PURPOSES		**40,724,144**

Test Year Taxable Income

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

	T2 S1 line #	Test Year Taxable Income
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0
Net-capital losses of preceding taxation years from Schedule 7-1	332	0
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME (C/F to tab "Tax Provision)		**40,724,144**

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited
Licence Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2010-0142

Other Additions

ARO Accretion Expenses	151,727
Capital Contributions Under S.12(1)x)	12,877,347
Lease inducement under 12(1)(x)	100,000
Deferred Revenue - 12(1)(a) add back	821,000
2010 ITC claimed	740,000
	14,690,074

Attachment to Test Year Adjusted Taxable Income

Toronto Hydro Electric System Limited

Licence Number: ED-2002-0497

File Number: RP-XXXX-XXXX, EB-2010-0142

Other Deductions

ARO Payments - Deductible for Tax	190,137
S.13(7.4) Election - Capital contributions	12,877,347
13(7.4) Election - Deduction of class 13	100,000
Deferred Revenue - 20(1)(m) deduction	821,000
Principal lease payments	230,630
Lease inducement amortization revenue	139,919
Lease inducement amortization revenue	621,471
	14,980,504

Attachment to Test Year Taxable Income

Toronto Hydro Electric System Limited
Licence Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2010-0142

Financing Fees Continuity

TAX TREATMENT

	Original Cost	Year of Expenditure	ITA Reference	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Ending NBV
2003 Debt Issue Costs	2,988,834	2003	S. 20(1)(e)	597,767	597,767	597,767	597,767	597,767														-
2005 LOC fee	470,000	2005	S. 20(1)(e)			94,000	94,000	94,000	94,000	94,000												-
2008 Agency fees	28,200	2008	S. 20(1)(e.1)						28,200													-
2007 Debt Issue Costs	1,341,690	2007	S. 20(1)(e)					268,338	268,338	268,338	268,338	268,338										-
2009 Agency Fees	28,500	2009	S. 20(1)(e.1)							28,500												-
2009 DBRS Rating Maintenance Fee	75,000	2009	S. 20(1)(e.1)							75,000												-
2010 Agency Fees	30,000	2010	S. 20(1)(e.1)								30,000											-
2010 LOC set up fee	50,000	2010	S. 20(1)(e.1)								50,000											-
2009 Debt Issuance	1,510,326	2009	S. 20(1)(e)							302,065	302,065	302,065	302,065	302,066								-
2010 Debt Issuance	1,146,000	2010	S. 20(1)(e)								229,200	229,200	229,200	229,200	229,200							-
2011 Agency Fees	30,000	2011	S. 20(1)(e.1)									30,000										-
2011 LOC set up fee	50,000	2011	S. 20(1)(e.1)									50,000										-
2011 Debt Issuance	792,000	2011	S. 20(1)(e)									158,400	158,400	158,400	158,400	158,400						-
Total			**S. 20(1)(e)**	**597,767**	**597,767**	**691,767**	**691,767**	**960,105**	**362,338**	**664,403**	**799,603**	**958,003**	**689,665**	**689,666**	**387,600**	**158,400**	**-**	**-**	**-**	**-**	**-**	**-**
Total			**S. 20(1)(e.1)**	**-**	**-**	**-**	**-**	**-**	**28,200**	**103,500**	**80,000**	**80,000**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Total			**TOTAL**	**597,767**	**597,767**	**691,767**	**691,767**	**960,105**	**390,538**	**767,903**	**879,603**	**1,038,003**	**689,665**	**689,666**	**387,600**	**158,400**	**-**	**-**	**-**	**-**	**-**	**-**

ACCOUNTING TREATMENT

	Original Cost	Year of Expenditure		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Ending NBV
2003 Debt Issue Costs	2,988,834	2003		194,435	298,883	298,883	298,883	60,962	293,874	312,895	333,148	354,711	377,670	164,490								
2005 LOC fee	470,000	2005				104,444	156,667	156,667	52,222													
2008 Agency fees	28,200	2008							18,800	9,400												
2007 Debt Issue Costs	1,341,690	2007						12,682	104,456	110,055	115,954	122,170	128,718	135,618	142,887	150,547	158,616	159,987				
2009 Agency Fees	28,500	2009								19,000	9,500											
2009 DBRS Rating Maintenance Fee	75,000	2009								6,250	68,750											
2010 Agency Fees	30,000	2010									20,000	10,000										
2010 LOC set up fee	50,000	2010									33,333	16,667										
2009 Debt Issuance	1,510,326	2009								15,946	122,701	128,427	134,420	140,694	147,260	154,132	161,325	168,854	176,734	159,833		
2010 Debt Issuance	1,146,000	2010									9,151	15,690	16,597	17,556	18,570	19,643	20,777	21,978	23,247	24,591	26,011	
2011 Agency Fees	30,000	2011										20,000	10,000									
2011 LOC set up fee	50,000	2011										33,333	16,667									
2011 Debt Issuance	792,000	2011										387	9,283	9,884	10,525	11,207	11,933	12,706	13,530	14,407	15,340	
Total				**194,435**	**298,883**	**403,327**	**455,550**	**230,311**	**469,352**	**473,546**	**712,537**	**701,385**	**693,355**	**468,242**	**319,242**	**335,529**	**352,651**	**363,525**	**213,511**	**198,831**	**41,351**	**-**

ACCOUNTING TREATMENT

	Original Cost	Year of Expenditure		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Ending NBV
2003 Debt Issue Costs	2,988,834	2003																				
2007 Debt Issue Costs	1,341,690	2007																				
2009 Agency Fees	28,500	2009																				
2009 DBRS Rating Maintenance Fee	75,000	2009																				
2010 Agency Fees	30,000	2010																				
2010 LOC set up fee	50,000	2010																				
2009 Debt Issuance	1,510,326	2009																				
2010 Debt Issuance	1,146,000	2010		27,514	29,103	30,785	32,563	34,445	36,434	38,539	40,766	43,121	45,612	48,247	51,035	53,983	57,102	60,401	63,890	67,581	71,485	
2011 Agency Fees	30,000	2011																				
2011 LOC set up fee	50,000	2011																				
2011 Debt Issuance	792,000	2011		16,334	17,393	18,520	19,720	20,998	22,358	23,807	25,350	26,993	28,742	30,604	32,588	34,699	36,948	39,342	41,892	44,606	47,497	
Total				**43,848**	**46,496**	**49,305**	**52,283**	**55,443**	**58,792**	**62,346**	**66,116**	**70,114**	**74,354**	**78,851**	**83,623**	**88,682**	**94,050**	**99,743**	**105,782**	**112,187**	**118,982**	**-**

ACCOUNTING TREATMENT

	Original Cost	Year of Expenditure		2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	Ending NBV
2003 Debt Issue Costs	2,988,834	2003																				-
2007 Debt Issue Costs	1,341,690	2007																				-
2009 Agency Fees	28,500	2009																				-
2009 DBRS Rating Maintenance Fee	75,000	2009																				-
2010 Agency Fees	30,000	2010																				-
2010 LOC set up fee	50,000	2010																				-
2009 Debt Issuance	1,510,326	2009																				-
2010 Debt Issuance	1,146,000	2010		75,615	23,968																	-
2011 Agency Fees	30,000	2011																				-
2011 LOC set up fee	50,000	2011																				-
2011 Debt Issuance	792,000	2011		50,575	53,852	49,979																1
Total				**126,190**	**77,820**	**49,979**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1**

Test Year PILs/ Tax Provision

Name of Utility: **Toronto Hydro-Electric System Limited**
Licence Number: **ED-2002-0497**
File Numbers: **RP-XXXX-XXXX, EB-2010-0142**

	Wires Only
Regulatory Taxable Income - From 'Test Year Taxable Income'	40,724,144
Corporate Income Tax Rate	28.25%
Total Income Taxes	11,504,571
Investment Tax Credits	740,000
Miscellaneous Tax Credits	270,000
Ontario Small Business Deduction	36,240
Total Tax Credits	1,046,240
Corporate PILs/Income Tax Provision for Test Year	10,458,331
Ontario Capital Tax	0

INCLUSION IN RATES

Income Tax (grossed-up)	14,576,071
Ontario Capital Tax (not grossed-up)	0
Tax Provision for 2011 EDR Model Rate Recovery **(EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)**	14,576,071

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	2,601,316	0	2,601,316
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	17,023,030	0	17,023,030
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	79,230,615	0	79,230,615
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	176,082,104	0	176,082,104
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0
1835	Overhead Conductors and Devices	1	0	0	0
1840	Underground Conduit	1	0	0	0
1845	Underground Conductors and Devices	1	0	0	0
1850	Line Transformers	1	50,725,985	0	50,725,985
1855	Services	1	0	0	0
1860	Meters	1	13,381,544	0	13,381,544
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**339,044,594**	**0**	**339,044,594**

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	9,166,247	0	9,166,247
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	42,662,639	0	42,662,639
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	95,582,807	0	95,582,807
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	27,313,992	0	27,313,992
1855	Services	2	0	0	0
1860	Meters	2	7,205,447	0	7,205,447
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility:	Toronto Hydro-Electric System Limited
Licence Number:	ED-2002-0497
File Numbers:	RP-XXXX-XXXX, EB-2010-0142

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**181,931,132**	**0**	**181,931,132**

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	24,914	0	24,914
1935	Stores Equipment	8	1,813,980	0	1,813,980
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	2,602,452	0	2,602,452
1960	Miscellaneous Equipment	8	4,228,318	0	4,228,318
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	29,191,326	0	29,191,326
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
	SUBTOTAL - CLASS 8		**37,860,990**	**0**	**37,860,990**
1920	Computer Equipment - Hardware	45	5,731,300	0	5,731,300
	SUBTOTAL - CLASS 45		**5,731,300**	**0**	**5,731,300**
1930	Transportation Equipment	10	5,301,287	0	5,301,287
	SUBTOTAL - CLASS 10		**5,301,287**	**0**	**5,301,287**
1925	Computer Software - CL12	12	-36,621,766	0	-36,621,766
	SUBTOTAL - CLASS 12		**-36,621,766**	**0**	**-36,621,766**
1630	Leasehold Improvements	13_1	-268,210	0	-268,210
1710	Leasehold Improvements	13_2	0	0	0
1810	Leasehold Improvements	13_3	0	0	0
1910	Leasehold Improvements	13_4	0	0	0
	SUBTOTAL - CLASS 13		**-268,210**	**0**	**-268,210**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
	SUBTOTAL - Generating Equipment		**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0

2001 Fair Market Value (FMV) Bump

Name of Utility: Toronto Hydro-Electric System Limited
Licence Number: ED-2002-0497
File Numbers: RP-XXXX-XXXX, EB-2010-0142

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
	SUBTOTAL - Capital Leases		**0**	**0**	**0**
1606	Organization	ECP	11,726,704	0	11,726,704
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
	SUBTOTAL - Eligible Capital Property		**11,726,704**	**0**	**11,726,704**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
	SUBTOTAL - Land		**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
	Yard Improvements	17	5,854,000	0	5,854,000
	Total FMV Bump-up		**550,560,031**	**0**	**550,560,031**

Fair Market Value (FMV) Bump Supplementry

Toronto Hydro Electric System Limited
Licence Number: ED-2002-0497
File Number: RP-XXXX-XXXX, EB-2010-0142

Class	Class Description	October 1, 2001 FMV Bump	Rate %	Remaining balance of Bump 2008	CCA of Bump 2009	Remaining balance of Bump 2009	CCA of Bump 2010	Remaining balance of Bump 2010	CCA of Bump 2011	Remaining balance of Bump 2011
1	Buildings; Electrical generating or distributing equipment and plant (including structures) acquired after 1987	339,044,594	4%	244,583,237	9,783,329	234,799,908	9,391,996	225,407,912	9,016,316	216,391,596
2	Electrical generating or distributing equipment acquired before 1988	181,931,132	6%	110,899,567	6,653,974	104,245,593	6,254,736	97,990,857	5,879,451	92,111,406
8	Office furniture and equipment; Electrical generating equipment acquired after May 25, 1976 that has a max load of not more than 15kws; Portable electrical generating equipment and radio communication equipment acquired after May 25, 1976	37,860,990	20%	6,352,020	1,270,404	5,081,616	1,016,323	4,065,293	813,059	3,252,234
10	Automotive equipment & vehicle; Computer hardware - computer hardware and system software	11,032,587	30%	636,007	190,802	445,205	133,561	311,644	93,493	218,151
12	Application software- - subject to half-year rule	(36,621,766)	100%	-	-	-	0	0	0	0
13	Leasehold Improvements - SL w/ estimated 5 year	(268,210)	20%	-	-	-	0	0	0	0
17	Yard improvements	5,854,000	8%	3,004,383	240,351	2,764,032	221,123	2,542,909	203,433	2,339,476
CEC	Cumulative Eligible Capital	11,726,704	7%	6,562,050	459,344	6,102,706	427,189	5,675,517	397,286	5,278,231
Total		**550,560,031**		372,037,264	18,598,204	353,439,060	**17,444,928**	**335,994,132**	**16,403,038**	**319,591,094**

REVENUE REQUIREMENT WORK FORM

Name of LDC:	Toronto Hydro-Electric System Limited	(1)
File Number:	EB-2010-0142	
Rate Year:	2011	**Version:** **2.11**

Table of Content

Notes:
(1) Pale green cells represent inputs
(2) Pale yellow cells represent drop=down lists
(3) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(4) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Data Input (1)

		Initial Application			(7)		Per Board Decision	
1	**Rate Base**							
	Gross Fixed Assets (average)	$4,404,200,772		($4,692,468)	$ 4,399,508,304		$4,399,508,304	
	Accumulated Depreciation (average)	($2,376,268,969)	(5)	$16,555,696	-$ 2,359,713,273		($2,359,713,273)	
	Allowance for Working Capital:							
	Controllable Expenses	$226,817,269		$22,680,813	$ 249,498,082		$249,498,082	
	Cost of Power	$2,242,116,161			$ 2,242,116,161		$2,242,116,161	
	Working Capital Rate (%)	12.90%			12.87%		12.87%	
2	**Utility Income**							
	Operating Revenues:							
	Distribution Revenue at Current Rates	$518,135,903		$0	$518,135,903			
	Distribution Revenue at Proposed Rates	$578,428,862		($22,995,455)	$555,433,407			
	Other Revenue:							
	Specific Service Charges	$7,580,526		$0	$7,580,526			
	Late Payment Charges	$4,900,000		$0	$4,900,000			
	Other Distribution Revenue	$7,240,556		$0	$7,240,556			
	Other Income and Deductions	$16,382		$0	$16,382			
	Operating Expenses:							
	OM+A Expenses	$220,014,886		$22,680,813	$ 242,695,699		$242,695,699	
	Depreciation/Amortization	$178,263,303		($33,111,390)	$ 145,151,913		$145,151,913	
	Property taxes	$6,802,382			$ 6,802,382		$6,802,382	
	Capital taxes							
	Other expenses							
3	**Taxes/PILs**							
	Taxable Income:							
	Adjustments required to arrive at taxable income	($17,273,077)	(3)		($52,280,484)			
	Utility Income Taxes and Rates:							
	Income taxes (not grossed up)	$20,189,870			$10,458,331			
	Income taxes (grossed up)	$28,139,192			$14,576,071			
	Capital Taxes		(6)			(6)		(6)
	Federal tax (%)	16.50%			16.50%			
	Provincial tax (%)	11.75%			11.75%			
	Income Tax Credits	($1,046,240)			($1,046,240)			
4	**Capitalization/Cost of Capital**							
	Capital Structure:							
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%			
	Short-term debt Capitalization Ratio (%)	4.0%	(2)		4.0%	(2)		(2)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%			
	Prefered Shares Capitalization Ratio (%)							
		100.0%			100.0%			
	Cost of Capital							
	Long-term debt Cost Rate (%)	5.37%			5.37%			
	Short-term debt Cost Rate (%)	2.07%			2.07%			
	Common Equity Cost Rate (%)	9.85%			9.85%			
	Prefered Shares Cost Rate (%)							

Notes:

(Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the data. Notes should be put on the applicable pages to explain numbers shown.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(3) Net of addbacks and deductions to arrive at taxable income.
(4) Average of Gross Fixed Assets at beginning and end of the Test Year
(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.
(6) Not applicable as of July 1, 2010
(7) Select option from drop-down list by clicking on cell M10. This columnallows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outsome of any Settlement Process can be reflected.

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Rate Base

Line No.	Particulars		Initial Application				Per Board Decision
1	Gross Fixed Assets (average)	(3)	$4,404,200,772	($4,692,468)	$4,399,508,304	$ -	$4,399,508,304
2	Accumulated Depreciation (average)	(3)	($2,376,268,969)	$16,555,696	($2,359,713,273)	$ -	($2,359,713,273)
3	Net Fixed Assets (average)	(3)	$2,027,931,803	$11,863,228	$2,039,795,031	$ -	$2,039,795,031
4	Allowance for Working Capital	(1)	$318,391,990	$2,336,534	$320,728,524	$ -	$320,728,524
5	**Total Rate Base**		$2,346,323,793	$14,199,762	$2,360,523,555	$ -	$2,360,523,555

Line No.	(1) **Allowance for Working Capital - Derivation**						
6	Controllable Expenses		$226,817,269	$22,680,813	$249,498,082	$ -	$249,498,082
7	Cost of Power		$2,242,116,161	$ -	$2,242,116,161	$ -	$2,242,116,161
8	Working Capital Base		$2,468,933,430	$22,680,813	$2,491,614,243	$ -	$2,491,614,243
9	Working Capital Rate %	(2)	12.90%	-0.02%	a 12.87%	0.00%	12.87%
10	Working Capital Allowance		$318,391,990	$2,336,534	$320,728,524	$ -	$320,728,524

Notes
(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Utility income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$578,428,862	($22,995,455)	$555,433,407	$ -	$555,433,407
2	Other Revenue	(1)	$19,737,464	($39,474,928)	$19,737,464	$ -	$19,737,464
3	Total Operating Revenues		$598,166,326	($62,470,383)	$575,170,871	$ -	$575,170,871
	Operating Expenses:						
4	OM+A Expenses		$220,014,886	$22,680,813	$242,695,699	$ -	$242,695,699
5	Depreciation/Amortization		$178,263,303	($33,111,390)	$145,151,913	$ -	$145,151,913
6	Property taxes		$6,802,382	$ -	$6,802,382	$ -	$6,802,382
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -		$ -	
9	Subtotal (lines 4 to 8)		$405,080,571	($10,430,577)	$394,649,994	$ -	$394,649,994
10	Deemed Interest Expense		$72,501,405	$438,773	$72,940,178	$ -	$72,940,178
11	Total Expenses (lines 9 to 10)		$477,581,977	($9,991,804)	$467,590,172	$ -	$467,590,172
12	**Utility income before income taxes**		$120,584,349	($52,478,578)	$107,580,699	$ -	$107,580,699
13	Income taxes (grossed-up)		$28,139,192	($13,563,121)	$14,576,071	$ -	$14,576,071
14	**Utility net income**		$92,445,157	($38,915,458)	$93,004,628	$ -	$93,004,628

Notes

(1)

Other Revenues / Revenue Offsets					
Specific Service Charges	$7,580,526	$ -	$7,580,526		$7,580,526
Late Payment Charges	$4,900,000	$ -	$4,900,000		$4,900,000
Other Distribution Revenue	$7,240,556	$ -	$7,240,556		$7,240,556
Other Income and Deductions	$16,382	$ -	$16,382		$16,382
Total Revenue Offsets	$19,737,464	$ -	$19,737,464	$ -	$19,737,464

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Taxes/PILs

Line No.	Particulars	Application				Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$92,445,157		$93,004,628		$93,004,628	
2	Adjustments required to arrive at taxable utility income	($17,273,077)		($52,280,484)		($17,273,077)	
3	Taxable income	$75,172,080		$40,724,144		$75,731,551	
	Calculation of Utility income Taxes						
4	Income taxes	$20,189,870		$10,458,331		$10,458,331	
5	Capital taxes	$ -	(1)	$ -	(1)	$ -	(1)
6	Total taxes	$20,189,870		$10,458,331		$10,458,331	
7	Gross-up of Income Taxes	$7,949,322		$4,117,740		$4,117,740	
8	Grossed-up Income Taxes	$28,139,192		$14,576,071		$14,576,071	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$28,139,192		$14,576,071		$14,576,071	
10	Other tax Credits	($1,046,240)		($1,046,240)		($1,046,240)	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	11.75%		11.75%		11.75%	
13	Total tax rate (%)	28.25%		28.25%		28.25%	

Notes

(1) Capital Taxes not applicable after July 1, 2010 (i.e. for 2011 and later test years)

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Initial Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$1,313,941,324	5.37%	$70,558,649
2	Short-term Debt	4.00%	$93,852,952	2.07%	$1,942,756
3	**Total Debt**	60.00%	$1,407,794,276	5.15%	$72,501,405
	Equity				
4	Common Equity	40.00%	$938,529,517	9.85%	$92,445,157
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$938,529,517	9.85%	$92,445,157
7	**Total**	100.00%	$2,346,323,793	7.03%	$164,946,563

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$1,321,893,191	5.37%	$70,985,664
2	Short-term Debt	4.00%	$94,420,942	2.07%	$1,954,514
3	**Total Debt**	60.00%	$1,416,314,133	5.15%	$72,940,178
	Equity				
4	Common Equity	40.00%	$944,209,422	9.85%	$93,004,628
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$944,209,422	9.85%	$93,004,628
7	**Total**	100.00%	$2,360,523,555	7.03%	$165,944,806

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Per Board Decision				
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$1,321,893,191	5.37%	$70,985,664
9	Short-term Debt	4.00%	$94,420,942	2.07%	$1,954,514
10	**Total Debt**	60.00%	$1,416,314,133	5.15%	$72,940,178
	Equity				
11	Common Equity	40.00%	$944,209,422	9.85%	$93,004,628
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$944,209,422	9.85%	$93,004,628
14	**Total**	100.00%	$2,360,523,555	7.03%	$165,944,806

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	At Current Approved Rates	At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$60,292,963		$37,297,504		$37,297,504
2	Distribution Revenue	$518,135,903	$518,135,899	$518,135,903	$518,135,903	$518,135,903	$518,135,903
3	Other Operating Revenue Offsets - net	$19,737,464	$19,737,464	$19,737,464	$19,737,464	$19,737,464	$19,737,464
4	**Total Revenue**	$537,873,367	$598,166,326	$537,873,367	$575,170,871	$537,873,367	$575,170,871
5	Operating Expenses	$405,080,571	$405,080,571	$394,649,994	$394,649,994	$394,649,994	$394,649,994
6	Deemed Interest Expense	$72,501,405	$72,501,405	$72,940,178	$72,940,178	$72,940,178	$72,940,178
	Total Cost and Expenses	$477,581,977	$477,581,977	$467,590,172	$467,590,172	$467,590,172	$467,590,172
7	**Utility Income Before Income Taxes**	$60,291,390	$120,584,349	$70,283,195	$107,580,699	$70,283,195	$107,580,699
8	Tax Adjustments to Accounting Income per 2009 PILs	($17,273,077)	($17,273,077)	($52,280,484)	($52,280,484)	($52,280,484)	($52,280,484)
9	**Taxable Income**	$43,018,313	$103,311,272	$18,002,711	$55,300,215	$18,002,711	$55,300,215
10	Income Tax Rate	28.25%	28.25%	28.25%	28.25%	28.25%	28.25%
11	**Income Tax on Taxable Income**	$12,152,674	$29,185,434	$5,085,766	$15,622,311	$5,085,766	$15,622,311
12	**Income Tax Credits**	($1,046,240)	($1,046,240)	($1,046,240)	($1,046,240)	($1,046,240)	($1,046,240)
13	**Utility Net Income**	$49,184,957	$92,445,157	$66,243,669	$93,004,628	$66,243,669	$93,004,628
14	**Utility Rate Base**	$2,346,323,793	$2,346,323,793	$2,360,523,555	$2,360,523,555	$2,360,523,555	$2,360,523,555
	Deemed Equity Portion of Rate Base	$938,529,517	$938,529,517	$944,209,422	$944,209,422	$944,209,422	$944,209,422
15	Income/Equity Rate Base (%)	5.24%	9.85%	7.02%	9.85%	7.02%	9.85%
16	Target Return - Equity on Rate Base	9.85%	9.85%	9.85%	9.85%	9.85%	9.85%
17	Sufficiency/Deficiency in Return on Equity	-4.61%	0.00%	-2.83%	0.00%	-2.83%	0.00%
18	Indicated Rate of Return	5.19%	7.03%	5.90%	7.03%	5.90%	7.03%
19	Requested Rate of Return on Rate Base	7.03%	7.03%	7.03%	7.03%	7.03%	7.03%
20	Sufficiency/Deficiency in Rate of Return	-1.84%	0.00%	-1.13%	0.00%	-1.13%	0.00%
21	Target Return on Equity	$92,445,157	$92,445,157	$93,004,628	$93,004,628	$93,004,628	$93,004,628
22	Revenue Deficiency/(Sufficiency)	$43,260,201	($0)	$26,760,959	($0)	$26,760,959	($0)
23	**Gross Revenue Deficiency/(Sufficiency)**	$60,292,963 **(1)**		$37,297,504 **(1)**		$37,297,504 **(1)**	

Notes:
(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

Version: 2.11

REVENUE REQUIREMENT WORK FORM

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$220,014,886		$242,695,699		$242,695,699	
2	Amortization/Depreciation	$178,263,303		$145,151,913		$145,151,913	
3	Property Taxes	$6,802,382		$6,802,382		$6,802,382	
4	Capital Taxes	$ -		$ -		$ -	
5	Income Taxes (Grossed up)	$28,139,192		$14,576,071		$14,576,071	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$72,501,405		$72,940,178		$72,940,178	
	Return on Deemed Equity	$92,445,157		$93,004,628		$93,004,628	
8	Distribution Revenue Requirement before Revenues	$598,166,326		$575,170,871		$575,170,871	
9	Distribution revenue	$578,428,862		$555,433,407		$555,433,407	
10	Other revenue	$19,737,464		$19,737,464		$19,737,464	
11	**Total revenue**	$598,166,326		$575,170,871		$575,170,871	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	($0)	(1)	($0)	(1)	($0)	(1)

Notes
(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

Residential

Consumption 800 **kWh**

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 18.2500	1	$ 18.25	$ 19.8300	1	$ 19.83	$ 1.58	8.66%
2	Smart Meter Rate Adder	monthly	$ 0.6800	1	$ 0.68	$ 0.6800	1	$ 0.68	$ -	0.00%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0157	800	$ 12.58	$ 0.0173	800	$ 13.86	$ 1.28	10.18%
6	Low Voltage Rate Adder			800	$ -		800	$ -	$ -	
7	Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)			800	$ -		800	$ -	$ -	
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider	per kWh	$ 0.0005	800	$ 0.40	$ -	800	$ -	-$ 0.40	-100.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0019	800	-$ 1.51	-$ 0.0019	800	-$ 1.51	$ -	0.00%
12	Regulatory Assets - Global Adjustment - RPP		$ -		$ -	$ -	0	$ -	$ -	
13	Regulatory Assets - 2011 Rate Rider	monthly	$ -		$ -	$ 0.0009	800	$ 0.71	$ 0.71	
14		monthly			$ -	$ 0.4100	1	$ 0.41	$ 0.41	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 30.39**			**$ 33.98**	**$ 3.58**	**11.79%**
17	RTSR - Network	per kWh	$ 0.0066	830.08	$ 5.50	$ 0.0065	830.08	$ 5.38	-$ 0.12	-2.26%
18	RTSR - Line and Transformation Connection	per kWh	$ 0.0054	830.08	$ 4.44	$ 0.0049	830.08	$ 4.04	-$ 0.40	-8.97%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 40.34**			**$ 43.40**	**$ 3.06**	**7.58%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	830.08	$ 4.32	$ 0.0052	830.08	$ 4.32	$ -	0.00%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	830.08	$ 1.08	$ 0.0013	830.08	$ 1.08	$ -	0.00%
22	Special Purpose Charge	per kWh	$ 0.0003725	830.08	$ 0.31	$ 0.0003725	830.08	$ 0.31	$ -	0.00%
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	830.08	$ 5.81	$ 0.0070	830.08	$ 5.81	$ -	0.00%
25	Energy			830.08	$ -		830.08	$ -	$ -	
26		per kWh	$ 0.0650	600	$ 39.00	$ 0.0650	600	$ 39.00	$ -	0.00%
27		per kWh	$ 0.0750	230.08	$ 17.26	$ 0.0750	230.08	$ 17.26	$ -	0.00%
28	**Total Bill (before Taxes)**				**$ 108.36**			**$ 111.42**	**$ 3.06**	**2.82%**
29	HST		13%		$ 14.09	13%		$ 14.48	$ 0.40	2.82%
30	**Total Bill (including Sub-total B)**				**$ 122.45**			**$ 125.90**	**$ 3.45**	**2.82%**
31	**Loss Factor (%)**	**Note 1**	3.76%			3.76%				

Notes:
Note 1: Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

Ontario

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: Toronto Hydro-Electric System Limited
File Number: EB-2010-0142
Rate Year: 2011

General Service < 50 kW

Consumption 2000 **kWh**

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge	monthly	$ 24.3000	1	$ 24.30	$ 26.0400	1	$ 26.04	$ 1.74	7.16%
2	Smart Meter Rate Adder	monthly	$ 0.6800	1	$ 0.68	$ 0.6800	1	$ 0.68	$ -	0.00%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate	per kWh	$ 0.0227	2000	$ 45.40	$ 0.0247	2000	$ 49.32	$ 3.92	8.63%
6	Low Voltage Rate Adder			2000	$ -		2000	$ -	$ -	
7	Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider	per kWh	$ 0.0001	2000	$ 0.24	$ -	2000	$ -	-$ 0.24	-100.00%
11	Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0018	2000	-$ 3.58	-$ 0.0018	2000	-$ 3.58	$ -	0.00%
12	Regulatory Assets - Global Adjustment - RPP	monthly	$ -		$ -	$ -	-	$ -	$ -	
13	Regulatory Assets - 2011 Rate Rider	per kWh	$ -		$ -	$ 0.0008	2000	$ 1.50	$ 1.50	
14		monthly			$ -	$ 0.4200	1	$ 0.42	$ 0.42	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 67.04**			**$ 74.38**	**$ 7.34**	**10.95%**
17	RTSR - Network	per kW	$ 0.0066	2075.2	$ 13.78	$ 0.0063	2075.2	$ 13.01	-$ 0.77	-5.57%
18	RTSR - Line and Transformation Connection	per kW	$ 0.0055	2075.2	$ 11.33	$ 0.0044	2075.2	$ 9.13	-$ 2.20	-19.41%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 92.15**			**$ 96.52**	**$ 4.37**	**4.74%**
20	Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	2075.2	$ 10.79	$ 0.0052	2075.2	$ 10.79	$ -	0.00%
21	Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0013	2075.2	$ 2.70	$ 0.0013	2075.2	$ 2.70	$ -	0.00%
22	Special Purpose Charge	per kWh	$ 0.0003725	2075.2	$ 0.77	$ 0.0003725	2075.2	$ 0.77	$ -	0.00%
23	Standard Supply Service Charge	monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)	per kWh	$ 0.0070	2075.2	$ 14.53	$ 0.0070	2075.2	$ 14.53	$ -	0.00%
25	Energy			2075.2	$ -		2075.2	$ -	$ -	
26		monthly	$ 0.0650	750	$ 48.75	$ 0.0650	750	$ 48.75	$ -	0.00%
27		per kWh	$ 0.0750	1325.2	$ 99.39	$ 0.0750	1325.2	$ 99.39	$ -	0.00%
28	**Total Bill (before Taxes)**				**$ 269.33**			**$ 273.70**	**$ 4.37**	**1.62%**
29	HST		13%		$ 35.01	13%		$ 35.58	$ 0.57	1.62%
30	**Total Bill (including Sub-total B)**				**$ 304.34**			**$ 309.28**	**$ 4.94**	**1.62%**
31	**Loss Factor**	**Note 1**	3.76%			3.76%				

Notes:
Note 1: See Note 1 from Sheet 1A. Bill Impacts - Residential

Previously filed as Exhibit M1, Tab 1, Schedule 1, Table 1

Table 1: Distribution Rates

	2010 Board-Approved	2011 Test	2011 Accounting Update
Residential			
Service Charge ($/30 days)	18.25	20.95	19.83
Volumetric Charge ($/kWh)	0.01572	0.01830	0.01732
General Service <50kW			
Service Charge ($/30 days)	24.30	27.26	26.04
Volumetric Charge ($/kWh)	0.02270	0.02582	0.02466
General Service 50-999kW			
Service Charge ($/30 days)	35.49	37.44	36.64
Volumetric Charge ($/kVA/30 days)	5.5840	5.8907	5.7648
Intermediate 1000-4999kW			
Service Charge ($/30 days)	659.80	671.21	665.26
Volumetric Charge ($/kVA/30 days)	4.0438	4.3508	4.3123
Large Use			
Service Charge ($/30 days)	2,874.02	2,988.58	2,920.08
Volumetric Charge ($/kVA/30 days)	4.2852	4.7083	4.6004
Streetlighting			
Connection Charge ($/conn/30 days)	1.32	1.64	1.50
Volumetric Charge ($/kVA/30 days)	29.2169	36.2742	33.2733
Unmetered Scattered Load			
Service Charge ($/30 days)	4.92	5.82	5.36
Connection Charge ($/conn/30 days)	0.50	0.59	0.54
Volumetric Charge ($/kWh)	0.06090	0.07300	0.06727

Previously filed as Exhibit K1, Tab 6, Schedule 2, Table 1

Table 1: Weather-normalized Revenues by Class

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11
1											
2			2007 Actual	2008 Board Approved	2008 Actual	2009 Board Approved	2009 Actuals	2010 Board Approved	2010 Bridge Year	2011 Test Year	2011 Test Year Accounting Update
3	Residential	Customer Charge	$ 87,571,092	$ 109,016,367	$ 109,142,515	$ 125,425,779	$ 124,940,074	$ 136,520,338	$ 136,772,131	$ 158,901,022	$ 150,406,075
4		Distribution Charge	$ 80,950,720	$ 84,087,737	$ 80,770,882	$ 78,795,128	$ 73,292,663	$ 80,785,554	$ 79,761,453	$ 91,257,867	$ 86,370,833
5	GS <50 kW	Customer Charge	$ 13,024,845	$ 15,612,169	$ 15,627,403	$ 17,266,106	$ 17,235,623	$ 19,438,004	$ 19,476,662	$ 21,820,846	$ 20,844,271
6		Distribution Charge	$ 44,578,497	$ 51,095,311	$ 46,319,092	$ 51,091,317	$ 43,674,294	$ 50,980,109	$ 50,024,558	$ 55,237,193	$ 52,755,584
7	GS 50-999 kW	Customer Charge	$ 3,560,395	$ 4,207,415	$ 4,371,793	$ 4,660,902	$ 4,864,615	$ 5,300,602	$ 5,541,352	$ 5,952,074	$ 5,824,893
8		Distribution Charge	$ 130,985,708	$ 135,168,539	$ 139,057,055	$ 132,485,235	$ 135,132,069	$ 151,388,290	$ 150,808,546	$ 160,870,841	$ 157,432,602
		Tranformer Allowance	(3,194,284)	(3,323,364)	(3,194,428)	(3,303,523)	(3,207,810)	(3,348,115)	(3,259,688)	(3,283,350)	(3,283,350)
9	GS 1000-4999 kW	Customer Charge	$ 4,512,691	$ 4,623,581	$ 4,591,895	$ 4,550,112	$ 4,419,606	$ 4,149,424	$ 4,126,169	$ 4,197,524	$ 4,160,314
10		Distribution Charge	$ 49,300,971	$ 51,652,905	$ 50,987,613	$ 50,928,853	$ 48,197,259	$ 45,992,501	$ 44,599,944	$ 46,702,195	$ 46,288,929
		Tranformer Allowance	(5,689,426)	(5,597,041)	(5,570,871)	(5,640,722)	(5,380,927)	(5,472,194)	(5,349,415)	(5,219,569)	(5,219,569)
11	Large Use	Customer Charge	$ 1,644,407	$ 1,719,231	$ 1,719,231	$ 1,573,308	$ 1,509,091	$ 1,643,460	$ 1,643,460	$ 1,708,970	$ 1,669,799
12		Distribution Charge	$ 19,355,677	$ 21,292,700	$ 20,929,847	$ 21,585,605	$ 20,658,791	$ 21,744,367	$ 22,440,185	$ 23,838,550	$ 23,292,243
		Tranformer Allowance	(3,205,353)	(3,258,184)	(3,151,786)	(3,284,666)	(3,093,615)	(2,981,877)	(3,078,352)	(2,976,922)	(2,976,922)
13	Street Lighting	Connection Charge	$ 512,068	$ 1,301,228	$ 1,301,824	$ 1,759,059	$ 1,756,561	$ 2,607,396	$ 2,611,998	$ 3,247,944	$ 2,970,681
14		Distribution Charge	$ 1,166,602	$ 4,948,163	$ 4,997,791	$ 6,360,852	$ 6,432,436	$ 9,514,299	$ 9,528,573	$ 11,843,359	$ 10,863,579
15	Unmetered Scattered Load	Cust/Conn Charge	$ 90,062	$ 120,807	$ 125,963	$ 132,004	$ 136,579	$ 199,795	$ 199,807	$ 235,970	$ 216,429
16		Distribution Charge	$ 1,023,330	$ 2,103,455	$ 2,082,060	$ 2,396,711	$ 2,343,830	$ 3,191,971	$ 3,407,586	$ 4,104,906	$ 3,782,699
17	Total	Customer Charge	$ 110,915,560	$ 136,600,799	$ 136,880,624	$ 155,367,270	$ 154,862,150	$ 169,859,019	$ 170,371,580	$ 196,064,350	$ 186,092,463
18		Distribution Charge	$ 327,361,504	$ 350,348,810	$ 345,144,340	$ 343,643,701	$ 329,731,342	$ 363,597,093	$ 360,570,846	$ 393,854,911	$ 380,786,469
		Transformer Allowance	(12,089,062)	(12,178,590)	(11,917,085)	(12,228,911)	(11,682,352)	(11,802,185)	(11,687,455)	(11,479,841)	(11,479,841)
19											
20	Total Distribution Revenue		$ 426,188,002	$ 474,771,019	$ 470,107,879	$ 486,782,061	$ 472,911,139	n/a	$ 519,254,972	$ 578,439,420	$ 555,399,090
21	Notes								Total Base Revenue Requirement	$ 578,428,862	$ 555,433,407
22	1. Based on Approved rates for each rate year								Difference due to Rounding of Rates	$ 10,558	-$ 34,317
23	2. Normalized to Test Year HDD and CDD										

Previously filed as Exhibit A1, Tab 8, Schedule 1, Table 1

Summary Bill Comparisons

Table 1

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6
		2010	**2011 Test**	**2011 Accounting Update**	**Annual Change - 2011 Test**	**Annual Change - Accounting Update**
1	**Rate Class**		**2011**	**2011**		
2						
3	**Residential (800 kWh)**					
4	Distribution	30.83	35.59	33.69	15.4%	9.3%
5	Rate Rider	(0.43)	0.29	0.29	167.1%	167.1%
6	Distribution and Rate Rider	30.40	35.88	33.98	18.0%	11.8%
7	Total Bill	108.15	113.11	111.21	4.6%	2.8%
8						
9	**General Service <50 kW (2,000 kWh)**					
10	Distribution	69.70	78.90	75.36	13.2%	8.1%
11	Rate Rider	(2.66)	(0.98)	(0.98)	63.2%	63.2%
12	Distribution and Rate Rider	67.04	77.92	74.38	16.2%	10.9%
13	Total Bill	268.80	276.71	273.17	2.9%	1.6%
14						
15	**GS 50-999 kW (349 kW, 388 kVA and 150,000 kWh)**					
16	Distribution	2,202.08	2,323.03	2,273.38	5.5%	3.2%
17	Rate Rider	(149.98)	(172.12)	(172.12)	-14.8%	-14.8%
18	Distribution and Rate Rider	2,052.10	2,150.91	2,101.26	4.8%	2.4%
19	Total Bill	17,100.17	17,319.50	17,269.86	1.3%	1.0%
20						
21	**GS 1000-4,999 kW (1,600 kW, 1,778 kVA, and 800,000 kWh)**					
22	Distribution	7,849.68	8,406.93	8,332.53	7.1%	6.2%
23	Rate Rider	(753.60)	(960.73)	(960.73)	-27.5%	-27.5%
24	Distribution and Rate Rider	7,096.07	7,446.20	7,371.80	4.9%	3.9%
25	Total Bill	87,539.63	87,148.48	87,074.07	-0.4%	-0.5%
26						
27	**Large Use (8,491 kW, 9,434 kVA and 4,500,000 kWh)**					
28	Distribution	43,300.60	47,406.68	46,320.25	9.5%	7.0%
29	Rate Rider	(4,428.50)	(5,918.13)	(5,918.13)	-33.6%	-33.6%
30	Distribution and Rate Rider	38,872.10	41,488.56	40,402.13	6.7%	3.9%
31	Total Bill	484,565.20	485,083.53	483,997.11	0.1%	-0.1%
32						
33	**Streetlighting (162,353 Connections, 25,506 kW and 9,182,013 kWh)**					
34	Distribution	959,512.76	1,191,469.35	1,092,198.91	24.2%	13.8%
35	Rate Rider	(19,126.95)	111,219.84	111,219.84	681.5%	681.5%
36	Distribution and Rate Rider	940,385.81	1,302,689.19	1,203,418.75	38.5%	28.0%
37	Total Bill	1,887,100.25	2,235,842.08	2,136,571.65	18.5%	13.2%
38						
39	**Unmetered Scattered Load (1 Connection, 1 kW and 365 kWh)**					
40	Distribution	27.65	33.06	30.45	19.6%	10.1%
41	Rate Rider	(0.36)	0.66	0.66	283.3%	283.3%
42	Distribution and Rate Rider	27.29	33.72	31.12	23.6%	14.0%
43	Total Bill	59.51	65.51	62.91	10.1%	5.7%

Note: Rate Riders include Contact Voltage Rate Rider as originally proposed