Engineering & Operations

2011 Gross Capital Budget

Project Code	Project Description/Scope	TOTAL BUDGET
A Substation Rebuilds		
11A1	Downtown Network Supply Upgrade	85,000
11A2	T1-L Switch Replacements	125,000
11A3	Sub 92 Rebuild	650,000
11A4	Sub 97 Voltage Conversion Phase 2	25,000
11A5	Sub 49 Animal Contact Protection	15,000
11A6	Substation Transformer Temperature Monitoring	10,000
11A7	Sub 23 Reclosing Relay Replacement	25,000
A Substation Rebuilds Total		**935,000**
B Subdivision Rebuilds		
11B1	Silicone Injection of Underground Cable	2,670,000
11B2	Hazelden Park Subdivision Rebuild	330,000
11B3	Replacement of Air Insulated Sectionalizing Enclosures	400,000
11B4	Fully Depreciated and Leaking Transformer Replacement	450,000
11B5	Residential Secondary Pedestal Replacements	25,000
11B6	Vault Transformer Replacements	250,000
11B7	Installation of Underground Backup Supply	110,000
11B8	Installation of Fault Indication on Padmounted Transformers	10,000
B Subdivision Rebuilds Total		**4,245,000**
C Main Feeder		
11C1	Ridout St 13.8 kV Voltage Conversion	350,000
11C2	26M43 Feeder Construction Phase 1	300,000
11C3	4M15 Feeder Extension	440,000
11C4	Crumlin Rd Feeder Upgrade and 8.32 kV Voltage Conversion	860,000
11C5	Sub 26 and 46 13.8 kV Voltage Conversion	240,000
C Main Feeder Total		**2,190,000**
D City Works		
11D1	City of London (Road authority) Relocations	500,000
D City Works Total		**500,000**
E Developer Projects		
11E1	Developer Driven Distribution Circuits Expansions and Relocations	830,000
11E2	Residential Secondary Service Upgrades	324,000
11E3	New Single Family Residential Underground Distribution	1,600,000
11E4	New Multi-Housing Underground Distribution	650,000
11E5	New Commercial Distribution Services	2,100,000
E Developer Projects Total		**5,504,000**
F Network		
11F1	Replacement of Network Vaults/Manholes/Transformers	1,320,000
11F2	Replacement of Primary & Secondary Cables	350,000
11F3	Eliminate East End Network - Adelaide St Area	465,000
11F4	Network PILC Replacement	200,000
11F5	Network 208 Voltage Risers	70,000
11F6	Manhole Cable Rebuilds	150,000
F Network Total		**2,555,000**
G Overhead Line		
11G1	Replacement of Fully Depreciated Poles	300,000
11G2	Replacement of Poles Susceptible to Poles Fires	500,000
11G3	Rebuild of Fully Depreciated Overhead Areas	2,497,000
11G4	13M15 Overhead Reliability Enhancements	160,000
11G5	26M53 Overhead Reliability Enhancements	110,000
11G6	Removals & Restoration of Overhead Plant	30,000
G Overhead Line Total		**3,597,000**
H Automation		
11H1	Recloser Installations	320,000
11H2	NetworkTemperature Monitoring Devices	10,000
11H3	RTU Replacement Program	50,000
11H4	SCADA Communications Enhancement	20,000
11H5	Migration to Digital Radios	65,000
H Automation Total		**465,000**
TOTAL ENGINEERING AND OPERATIONS CAPITAL BUDGET		**19,991,000**

2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11A1
	Project Name:	Downtown Network Supply
	Project Driver:	REL

Project Title: Downtown Network Supply Upgrade - Restorations & Design Enhancements

Project Manager: Cole Tavener

Project Tech.: Rolf Reiners

Supporting Reference Material

Refurbishment of the Electric Supply to London's Core Network System, Issued July 31, 2008

Description/Justification

London Hydro previously identified the need to make alterations and improvements to the 13.8kV network. This work was scheduled over 3 years (2008 - 2010). In the first two years the detailed engineering was completed, transformers, switchgear, protections, controls and neutral grounding resistors were procured and civil works were installed. The final year's work involved the completion of interstation wiring, the installation and integration of new network dash cables and the commissioning of the entire installation.

This capital plan is required to make restorations to substation construction sites, improve safety at the Pall Mall site, enhance substation ergonomics and install permanent station services.

COST ESTIMATE

Section - 110	$85,000

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

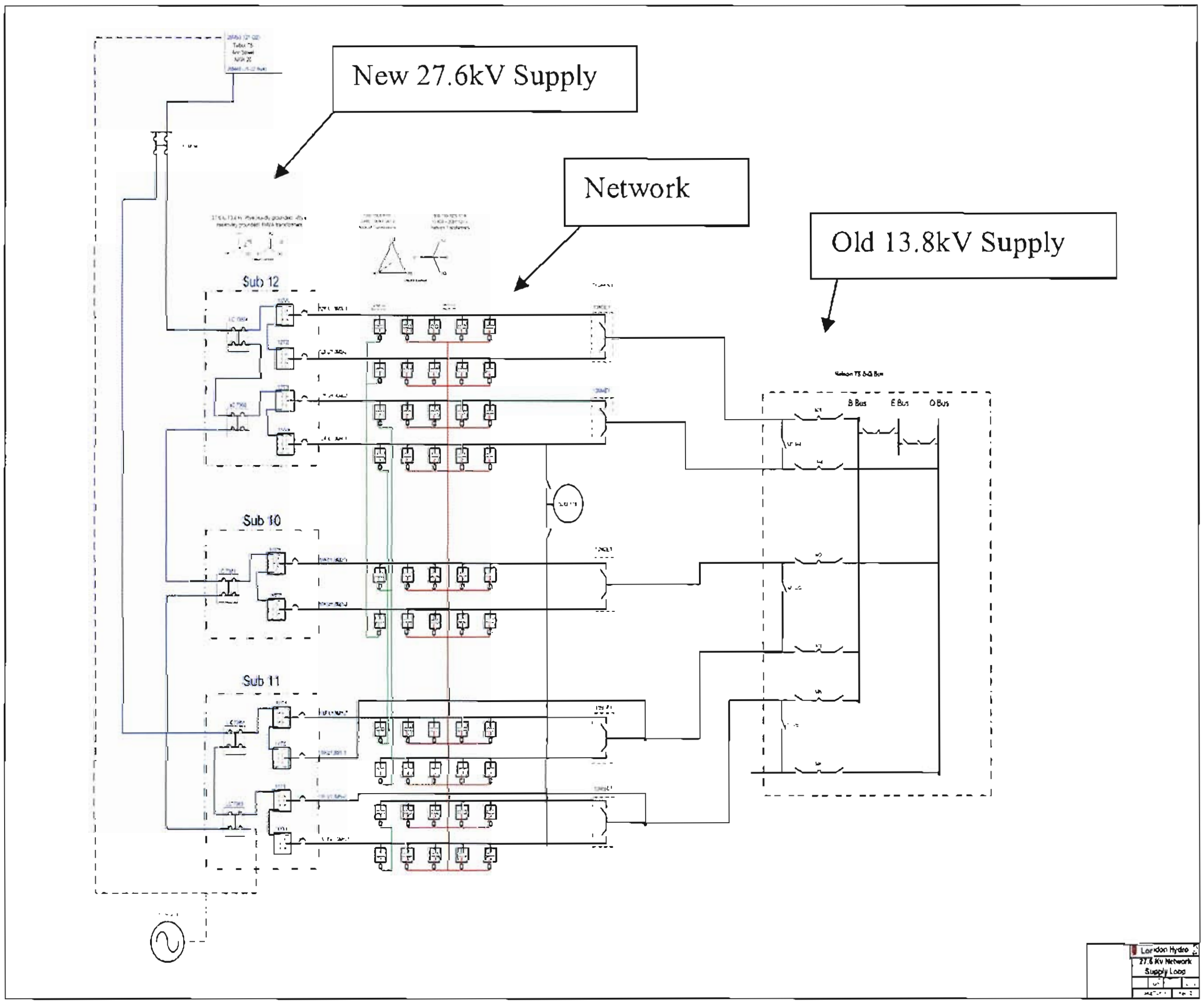
Downtown Network Supply Upgrade

Project 11A1

This project is the final phase of a multiyear project to convert the supply to the downtown Network system to 27.6kV from the 60 year old 13.8kV system. Completion of this project will enable the elimination of over 10kM of fully depreciated 13.8kV PILC (Paper Insulated Lead Covered) cable, provide enhanced automation, provide the ability to switch to an alternate 27.6kV supply, and will enable the load to be removed from Nelson T.S. to facilitate its planned reconstruction at 27.6kV.

The remaining work involves the completion of station wiring, the installation and integration of new network dash cables and the finalizing the commissioning of the entire installation.

London Core Supply Schematic



London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:**	11A2
		Project Name:	T1-L Switch Replacements
		Project Driver:	REL
Project Title:	T1-L Switch Replacements		
Project Manager:	Cole Tavener	**Project Tech.:**	Rolf Reiners
Supporting Reference Material	2008 Substation Deficiency Report		

Description/Justification

As part of London Hydro's continuous substation assessment process, it was found that a number of T1-L switches, which are the primary side station transformer switch, have developed considerable amounts of rust, holes, and/or are collecting water. Previous corrective measures such as paint, sealant and tar to protect the metal structure's surface have prolonged the in-service life of these devices, but have not provided a permanent solution.

The purpose of this capital plan is to continue a phased replacement of the identified depreciated T1-L switches. In 2011, we will replace the T1-L switches at Substations 24 and 25.

COST ESTIMATE

Section - 110	**$125,000**

Prepared By:	Cole Tavener Assistant Distribution Engineer
Approved By::	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

T1-L Switch Replacements

Project 11A2

T1-L is the designation provided to primary side substation transformer switches. London Hydro, through its continuous substation assessment process has determined that a particular style of T1-L switch (S&C) is susceptible to considerable amounts of rust, holes, and/or collecting water. These defects pose potential safety and reliability issues that must be addressed. The problem with the identified switches is a ledge design on the incoming chamber. Newer London Hydro T1-L switches do not contain a ledge and therefore should not suffer from the above mentioned defects. Below are two pictures: one illustrating the defective T1-L switches with an incoming ledge chamber design (1) and the second showing the latest London Hydro standard T1-L switch.

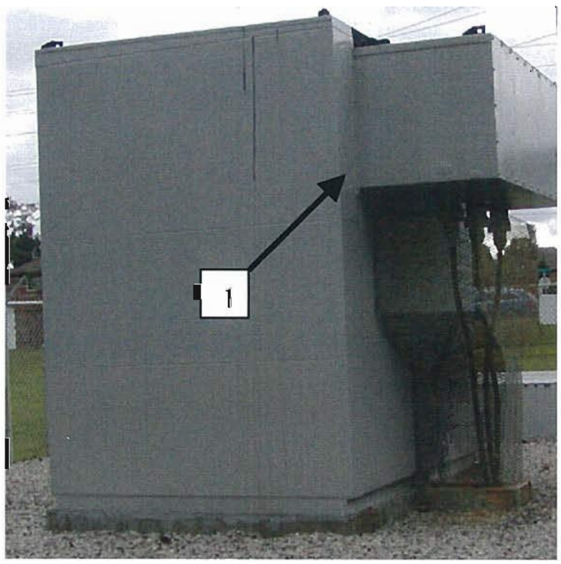


Figure 1 – Identified Defective T1-L Switch

Figure 2 – Replacement T1-L Switch

London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:** **Project Name:** **Project Driver:**	11A3 Substation 92 Rebuild REL

Project Title:	Substation 92 Rebuild
Project Manager:	Cole Tavener
Project Tech.:	Rolf Reiners
Supporting Reference Material	2008 Substation Deficiency Report
Description/Justification	This project is to rebuild Substation 92 in situ. This fully depreciated station was built in 1959. A new transformer, switchgear, relays, remote terminal unit (RTU) and feeder egresses will be installed.

COST ESTIMATE

Section - 110	**$650,000**

Prepared By:	Cole Tavener Assistant Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

Substation 92 Rebuild
Project 11A3

Substation 92 provides a critical hub for the 4kV system in the Clarke Road and Wavell Street area. In 2008, the peak load during the previous 5-year period was 99% of the substation's capacity rating – the substation has only one transformer. The transformer is over 50 years old and is prone to leaking. The older design has open 4kV bus. The 2008 substations deficiency report identified Substation 92 as the second worst substation in London Hydro's system.

Figure 2: Open 4kV Bus.

Figure 2: Aged Transformer.

London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:**	11A4
		Project Name:	Voltage Conversion Phase 2
		Project Driver:	REL

Project Title: Substation 97 Voltage Conversion Phase 2

Project Manager: Cole Tavener

Project Tech.: Rolf Reiners

Supporting Reference Material: 2008 Substation Deficiency Report

Description/Justification

The primary factor driving this project is the 2008 Substation Deficiency Report which identified Sub 97 as the most deficient substation at London Hydro. Work completed in 2010, to convert load to the 27.6kV system, has resulted in a single feeder connected to this station. The station will be reconfigured to supply the new feeder configuration and reduced load.

COST ESTIMATE

Section - 110	**$25,000**

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Substation 97 Voltage Conversion Phase 2
Project 11A4

Two of the three fully depreciated 8.32kV feeders in the rural area south of London have been rebuilt at 27.6kV leaving Sub 97 with a single feeder. This substation will be partially reconfigured to provide a simpler and more efficient supply that is suitable for the remaining load.

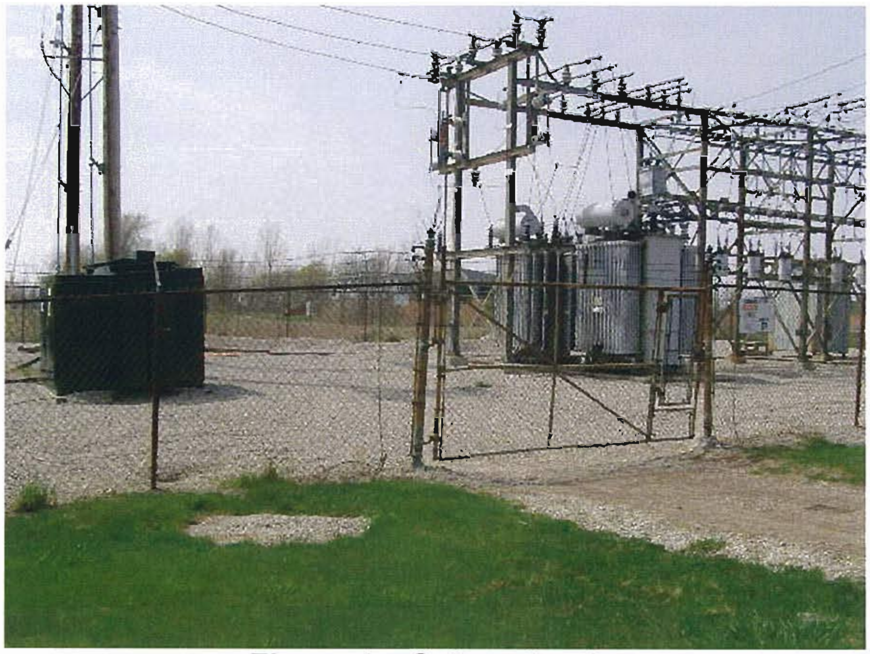


Figure 1 – Substation 97

Figure 2 – Substation 97 Overhead Bus

2011 ASSET MANAGEMENT PLAN
E&O Department

London Hydro

Project Number:	11A5
Project Name:	Animal Contact Protection
Project Driver:	REL

Project Title:	Substation 49 Animal Contact Protection		
Project Manager:	Cole Tavener	Project Tech.:	Rolf Reiners
Supporting Reference Material			

Description/Justification

Substation 49 has the same bus design as Substation 35. Following a number of outages caused by animal contacts, a deficiency was identified in the bus design at Substation 35. To eliminate the deficiency, bus covers were installed. The bus covers have proven to be effective at preventing outages caused by animal contact since their installation in 2008. Having proven to be an effective solution, bus covers will now be installed at Substation 49.

COST ESTIMATE

Section - 110	$15,000

Prepared By:	Cole Tavener Assistant Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

Substation 49 Animal Contact Protection
Project 11A5

In recent years, a number of substation outages have been caused by flashovers due to animal contact. This type of outage leaves entire neighbourhoods without power until a member of the substation maintenance department can respond. To eliminate this type of outage and improve SAIDI (System Average Interruption Duration Index) many utilities have begun installing bus covers. London Hydro installed bus covers at Substation 35 in 2008 and it has proven to be effective at preventing substation outages due to animal contact. This solution is directly applicable to Substation 49 as it has the same bus design as Substation 35.

Figure 1 – Substation 49 Exposed Bus.

Figure 2 – Substation 35 Covered Bus.

2011 ASSET MANAGEMENT PLAN

E&O Department

Project Number:	11A6
Project Name:	Temperature Monitoring
Project Driver:	REL
Project Title:	Substation Transformer Temperature Monitoring
Project Manager:	Cole Tavener
Project Tech.:	Rolf Reiners
Supporting Reference Material	Asset Management Plan 2010 to 2024

Description/Justification

Temperature monitoring allows London Hydro to better manage the loading of substation transformers. Older transformers and transformers exposed to heavier loads are the primary drivers for the installation of this technology. The enhanced monitoring will also help protect our investment in newer and larger transformers. On-line transformer temperature monitoring was provided during the rebuild of Substation 93. By mimicing the Substation 93 design, on-line transformer temperature monitoring will be provided to four substations in 2011:

1) Substation 25
2) Substation 33
3) Substation 51
4) Substation 96

COST ESTIMATE

Section - 110	**$10,000**

Prepared By:	Cole Tavener Assistant Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

Substations Transformer Temperature Monitoring
Project 11A6

Over half of the substation transformers in London Hydro's fleet are expected to reach end-of-life within 15 years. Substation transformers are worth from $60,000 to $120,000 each. Since the exact lifespan of a transformer is unknown, the availability of asset condition information becomes highly critical as an asset approaches end-of-life or it is exposed to higher loads. Of the available on-line monitoring technologies for substation transformers, temperature monitoring is the least expensive. Providing transformer temperature information to system operators, via SCADA, will enable enhanced analysis of switching operations and the immediate dispatch of substation maintenance personnel as required.

Figure 1: Transformer Temperature Gauge circa 1960

Figure 2: On-line Temperature Monitoring Device

London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:** **Project Name:** **Project Driver:**	11A7 Reclosing Relay Replacement REL

Project Title:	Substation 23 Reclosing Relay Replacement
Project Manager:	Cole Tavener
Project Tech.:	Rolf Reiners
Supporting Reference Material	2008 Substation Deficiency Report

Description/Justification

The reclosing relays at Sub 23 are over 45 years old and are not operating reliably. In 2003, the reclosing-timer relays at substations 18, 24, 25 and 27 were replaced. This project will either be completed using a modern electromechanical relay to mimic the original design, or the existing relays will be replaced with intelligent electronic devices (IEDs). The latter option is interactive with the design of a substation remote terminal unit (RTU) replacement.

COST ESTIMATE

Section - 110	**$25,000**

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Substation 23 Reclosing Relay Replacement
Project 11A7

The reclosing relays at Sub 23 are over 45 years old. Replacement of the reclosing relays at Substation 23 is required to enhance SAIDI (System Average Interruption Duration Index). The need for this project to be completed was identified in the 2008 substation deficiency report. In 2003, relays were replaced at Substations 18, 24, 25 and 27 to address a similar deficiency.

Figure 1: Substation 23 Reclosing-Timer Relays

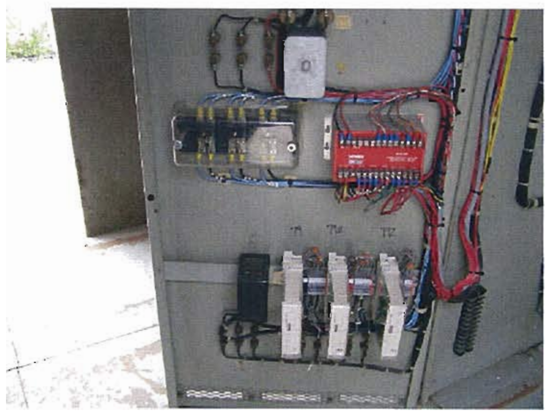


Figure 2: Substation 24 "Like-for-Like" Replacement Relays

Figure 3: Intelligent Electronic Device (IED) Replacement

2011 ASSET MANAGEMENT PLAN **Project Sheet**	**Project Number:**	11B1
	Project Name:	Cable Silicone Injection
	Project Driver:	REL

Project Title: Silicone Injection of Underground Cable

Project Manager: Jagoda Borovickic | **Project Tech.:** Scott Lasseter/Dane Kirilovic

Supporting Reference Material

1. Engineering Report Update 2009, ***Rehabilitation of Aging Underground Residential Distribution Systems*** - November 2009
2. ***2009 SPOORE Geo Media Implementation*** - June 2009 Presentation
3. 2010 SPOORE Analysis Map

Description

The capital investment in cable rehabilitation for 2011 is on the rise and expanding on the approach from last year's initiative of cable silicone injection.

This item covers rehabilitation of underground aged cable by means of silicone injection in four (4) aged subdivisions. The total length to be injected is estimated at 50+ km of polymeric cable (25+ years old). These four areas were selected using the SPOORE analysis (modeled in the GIS based software *Geo Media)*, which ranks the subdivisions' performance using a five-year history of failures on cables and transformers, as well as a visual representation of leaking transformers from the annual OEB inspections.

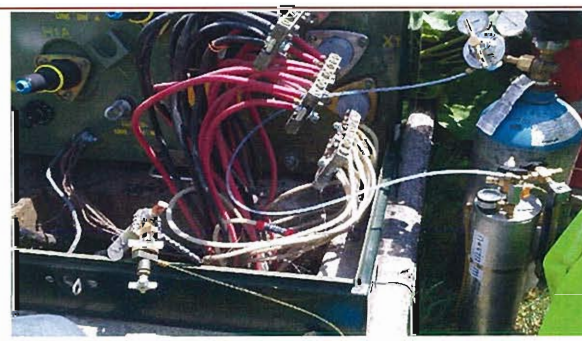
Silicone injection technology increases the lifespan of polymeric cable, adding up to another 40 years of service. Last year, London Hydro launched this process anticipating to tackle approximately 30 km of old cable. Where the existing cable had been spliced in the past new splices were installed after injecting the cable from the splice towards the transformer. This technique has the advantage of minimizing the sections of cable that would require a complete replacement, estimated to be much more costly than injection.

The rehabilitation will include transformer replacements (in advance) that are deteriorated or leaking, which also improves the customers' downtime by more effective switching (the new transformers are equipped with dual load break switches that allow flexible open points).

It is estimated that at this rate of annual investment, the existing population of cable that has passed its lifetime could be addressed over a four to five year time span. Eventually, a consistent multi-year plan of rehabilitation could bring London Hydro to a complete renewal of all the underground plant that should be retired.

COST ESTIMATE

Section - 145	**$2,670,000**



Prepared By: Cristina Terek, P.Eng.
Distribution Reliability Engineer

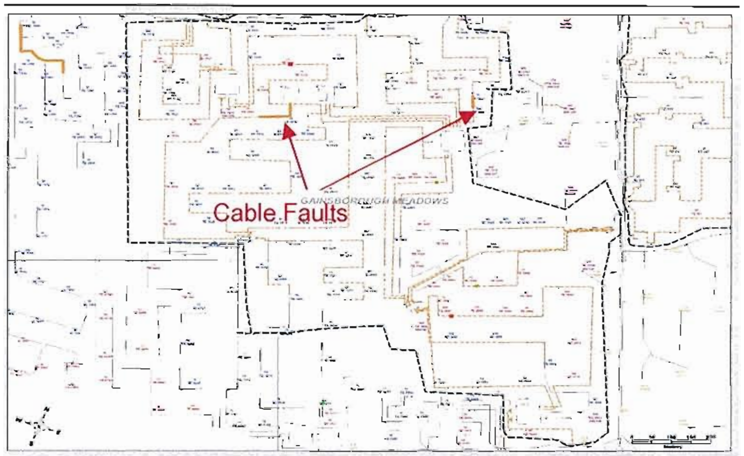
Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

1. Gainsborough Meadows (27.6 kV supply)

This subdivision occupies a very large area in the north-west corner of the city (south of White Hills). The cable in general is over 35 years old. Two large cable failures occurred in the course of five years, adding to that extensive downtime from several transformer failures.

This work will include changing out as many as 20 padmounted transformers (mostly live-fronts) and injecting up to 17 km of polymeric cable. It is expected based on the experience from the 2010 projects that multiple splices will be found in the field, which increases the project duration and correspondingly the costs associated due to digging up the splices for injection. As such, some contingency dollar value has been added with every project in this budget item.

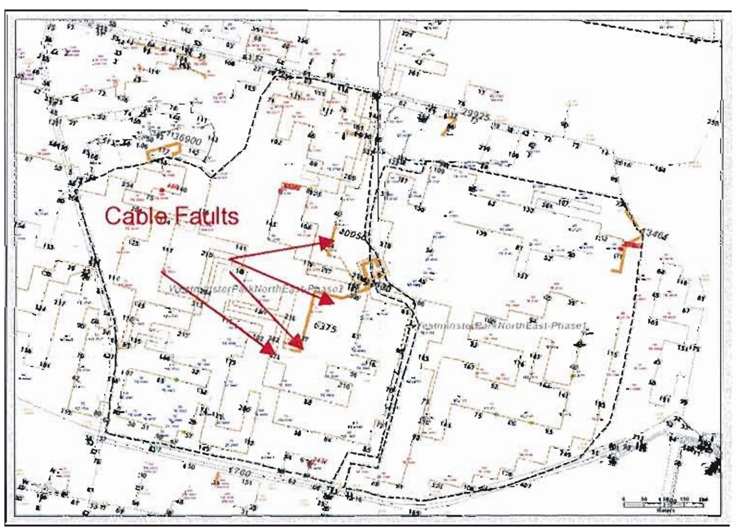
The SPOORE analysis identifies this subdivision as the most unreliable based on outage data from the past five years.

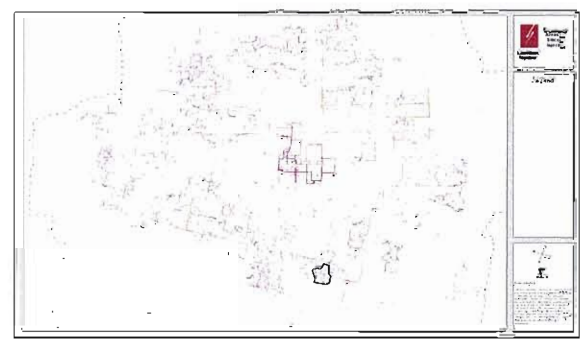


2. Westminster Park East - Phase 2 (27.6 kV supply)

This large subdivision known as Westminster Park East has suffered noticeable deterioration in performance lately. In 2010, Phase 1 of this project addressed almost 8 km of aged cable (35+) in addition to exchanging a significant number of depreciated transformers. It is expected that following Phase 2, the improvement will be visible.

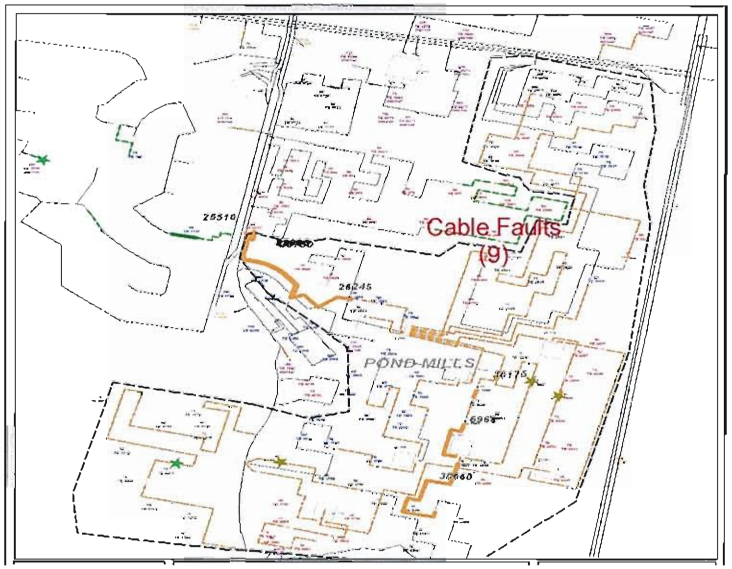
Five failures on cable have been counted already in the area to be addressed as Phase 2. This second phase of the project will involve rehabilitation similarly as Phase 1: replacement of over 40 padmounted transformers; silicone injection will be performed on an estimated 11.5 km of cable overall.





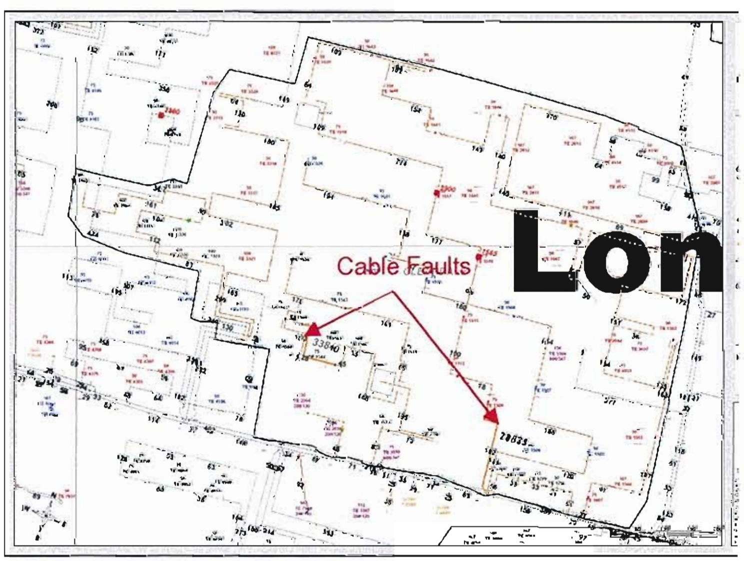
3. *Pond Mills (27.6 kV supply)*

Pond Mills is a subdivision where cable faults have intensified severely over the last couple of years: a total of nine outages were caused by cable failures, some within the same segment. After new risers were installed in 2010 to deal with the recurrent failures, the area now is in complete need of rehabilitation. The budget for this project is intended to cover 28 new transformers that need to be changed out and injection of an estimated 14.5 km of cable. Like other older areas, numerous splices are expected to be encountered during the injection process.



4. *Cleardale (27.6 kV supply))*

Only three cable faults in the first part of 2010 ranked this subdivision the fourth unreliable in the underground system. Part of the extended outages was also due to a radial supply which will be addressed separately by closing the loop. The broader scope of rehabilitation in this area will also involve some 10 km of cable injection added to the replacement of as many as half of the distribution transformers that supply power to the area. Both these measures combined are expected to improve the reliability of supply long-term.



London Hydro

2011 ASSET MANAGEMENT PLAN

Project Sheet

Project Number: 11B2

Project Name: Hazelden Park UG Rebuild

Project Driver: REL

Project Title: Hazelden Park Subdivision Rebuild

Project Manager: Jagoda Borovickic

Project Tech.: Jamie Macpherson

Supporting Reference Material

1. Engineering Report Update 2009, ***Rehabilitation of Aging Underground Residential Distribution Systems*** - November 2009
2. ***2009 SPOORE Geo Media Implementation*** - June 2009 Presentation
3. 2010 SPOORE Analysis Map

Description

This budget item targets a complete rehabilitation of this small underground residential subdivision currently supplied at 4 kV. New 28 kV rated cable (approx 3.2 km) will be installed to replace the existing cable that is aged: a mixture of 15 kV and 5 kV rated cable. In addition three live-front transformers will be changed out. The subdivision will continue to remain supplied from Sub-44.

The subdivision rehabilitation is based on the results of the SPOORE analysis that indicates the area as being the 5th least reliable based on its last 5-year performance: the downtime was from two failures on the cable and from one defective transformer. Silicone injection at this cable rating will not be performed. Future conversion of the area would render the original expense for injection of cable rated lower than 28 kV practically unwise and uneconomical.

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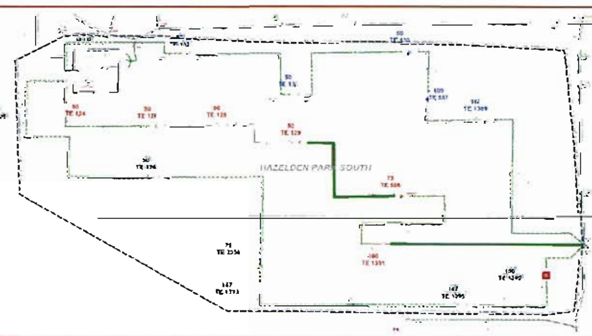
COST ESTIMATE

Section - 145 **$330,000**



Prepared By: Cristina Terek, P.Eng.
Distribution Reliability Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11B3
	Project Name:	Replacement of SE's
	Project Driver:	REL

Project Title:	Replacement of Air Insulated Sectionalizing Enclosures
Project Manager:	Jagoda Borovickic
Project Tech.:	Jamie Macpherson
Supporting Reference Material	Distribution Reliability Report, ***Performance Review and a New Perspective for In-service 27.6 kV Three-Phase Air Insulated Sectionalizing Enclosures,*** May 2006 ***Reliability In Review for the 2007 Operating Year***, September 2007

Description/Justification

Year 2011 will be the sixth year into this long-term project intended to eliminate air-insulated switchgear from the 27.6 kV distribution system. This budget item is being increased from previous years. After the initial stage of aggressive replacement, the performance improved; hence less money was allocated in the following years.

In the 2011 budget it is anticipated that ten units (such as the one below) will be addressed in total, leaving about 75 more to eliminate across the 27.6 kV system (approx half of the original count at the beginning of the program).

COST ESTIMATE

Section - 145 **$400,000**

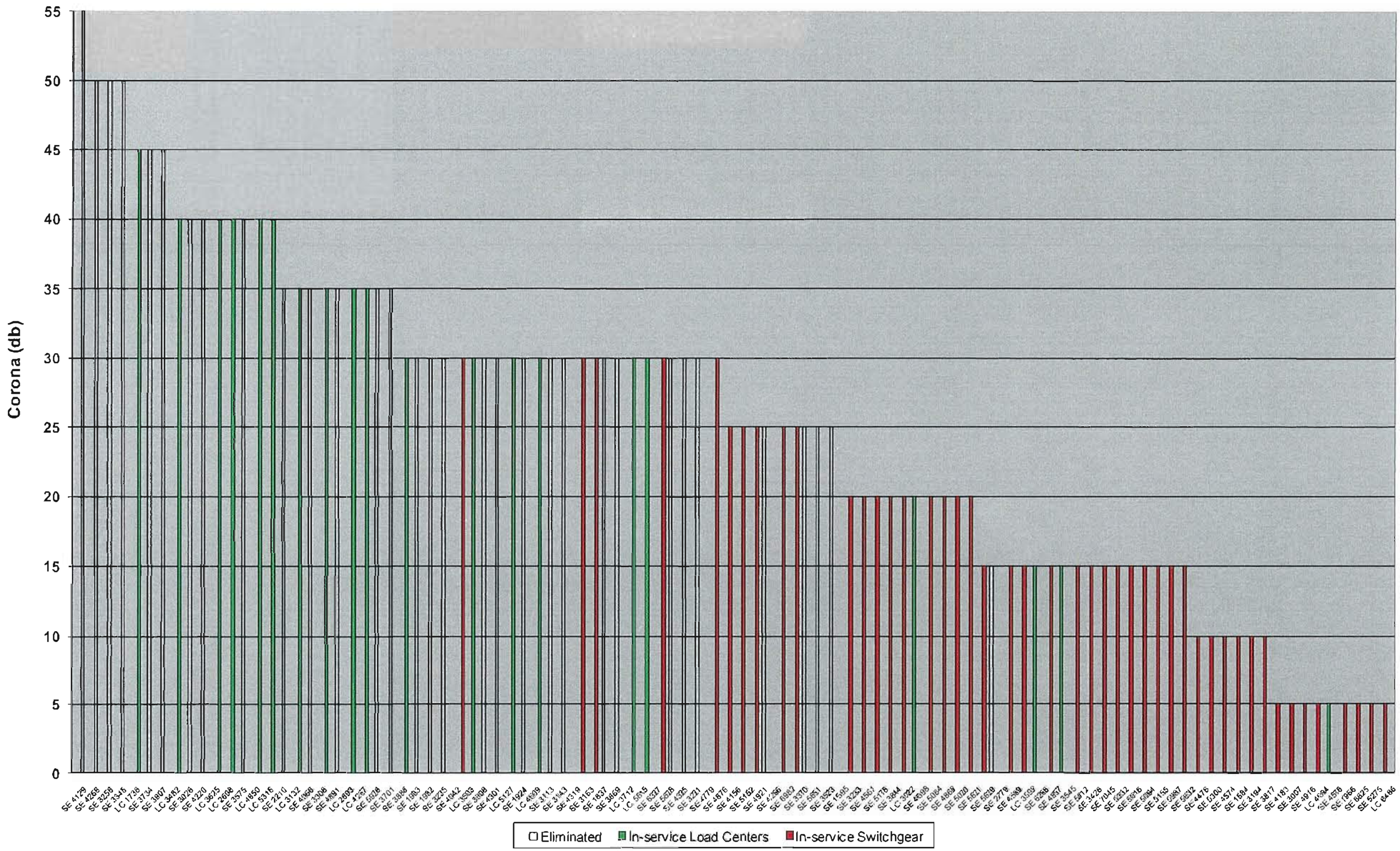
Prepared By: Cristina Terek, P.Eng.
Distribution Reliability Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Replacement of Air-Insulated Sectionalizing Enclosures Project 11B3

Earlier research and analysis into the failures of air-insulated switching enclosures on the 27.6 kV system led to the publication of an in-depth report at London Hydro in 2006. The findings and recommendations have helped with targeting the most prone-to-failure units which were eliminated without delay. From the time the higher-risk units started to be changed out (2006) to-date, more than 50 have now been addressed. The work conducted over the past four years shows a remarkable, positive impact in performance. The chart illustrates that of the equipment that was found at some risk, about half have been dealt with either by replacement (green bars), or by system reconfiguration (transparent bars). The existing units (red bars) that remain in service will be addressed in the following years as part of this multi-year program.

Status of Switchgear Equipment - 2010 Year-End



2011 ASSET MANAGEMENT PLAN
E&O Department

London Hydro

Project Number:	11B4
Project Name:	Leaking Transformers
Project Driver:	SAF

Project Title:	Fully Depreciated and Leaking Transformer Replacement
Project Manager:	Jagoda Borovickic
Project Tech.:	Steve Lavell
Supporting Reference Material	OEB Audits conducted by field staff

Description/Justification

London Hydro field staff conduct annual audits of padmounted transformers in accordance with the requirements of the Ontario Energy Board. These audits are meant to identify defective/end of life transformers and transformers which may be weeping oil around the primary and secondary bushings. These matters are usually caused by transformer aging and the degradation of the sealing gaskets.

This project covers the cost to identify and replace the fully depreciated and leaking transformers.

COST ESTIMATE

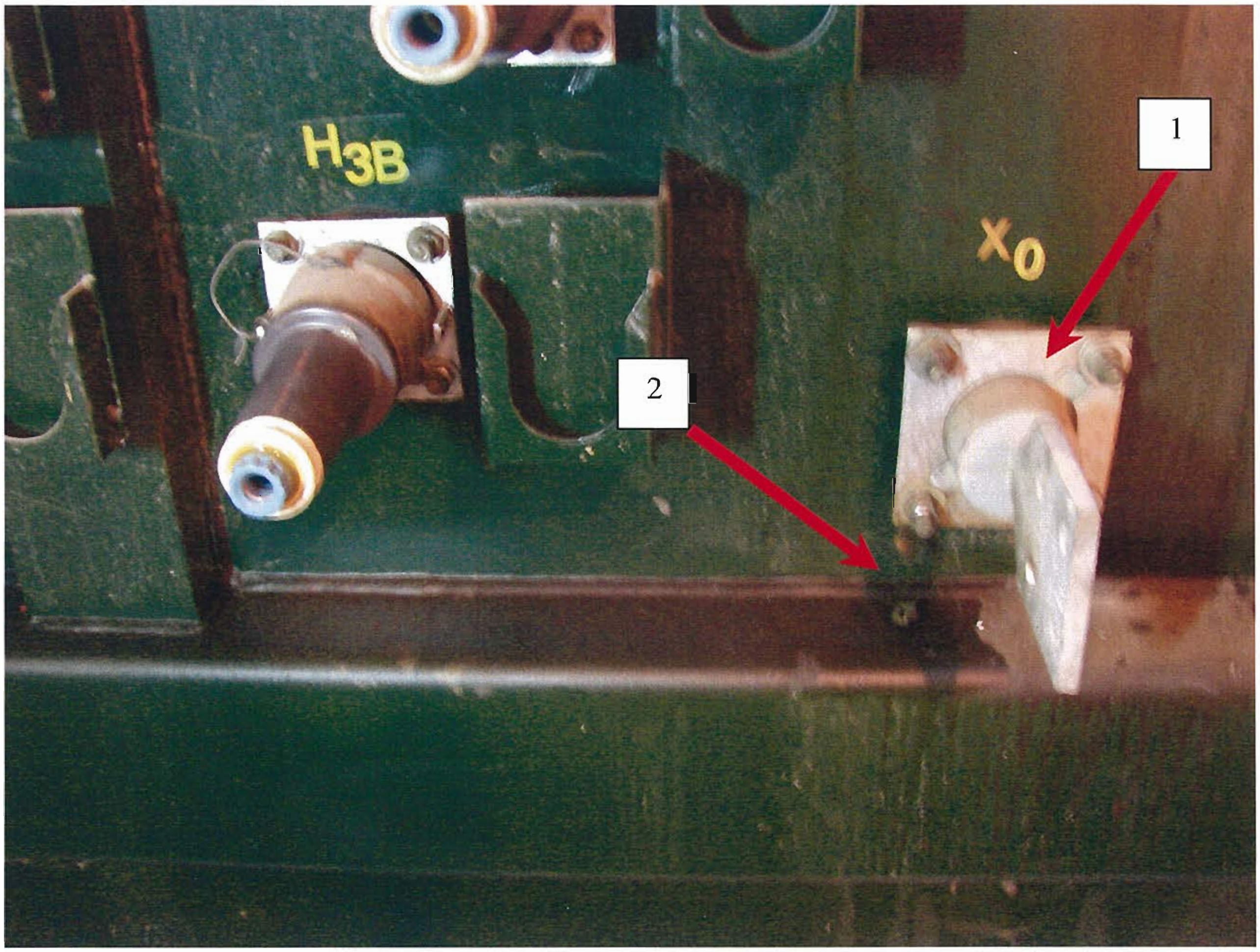
Section - 145	**$450,000**

Prepared By: Jagoda Borovickic, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Fully Depreciated and Leaking Transfomer Replacement
Project 11B4

London Hydro performs OEB audits on the condition of the padmounted transformers in our system. These audits help us identify potentially defective/end of life transformers for replacement. London Hydro takes its environmental responsibilities seriously and as such continues to invest capital dollars into the identification and removal of these suspect transformers. Historically, we have been identifying 65 suspect transformers per audit year. The cost to replace a typical suspect transformer ranges between $7,500 - $15,000 depending on transformer type. The allocated amount for this project is $450,000.



1) Neutral Bushing
2) Oil Leak

London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:** **Project Name:** **Project Driver:**	11B5 Secondary Pedestal Replacement REL
Project Title:	Residential Secondary Pedestal Replacement		
Project Manager:	Jagoda Borovickic	**Project Tech.:**	Scott Lasseter
Supporting Reference Material	OEB Audits conducted by field staff		

Description/Justification

London Hydro has a large number of single phase low voltage junction pedestals active in our system. These units are typically used in residential areas. They allow one common bus cable to be divided into several service cables to feed multiple meters. Some of these units are reaching their end of life. They are in excess of 30 years old and the enclosures are starting to corrode. It has also been found that the connections and barriers within the existing units are beginning to fail.

This budget targets the replacement of these existing units with our new non-metalic units shown below. The replacements will be prioritized based on the findings from our OEB audits conducted by field staff and address areas where problems have been experienced in the past.

COST ESTIMATE

Section - 145	**$25,000**

New replacement unit shown to right

Prepared By: Jagoda Borovickic
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

2011 ASSET MANAGEMENT PLAN Project Sheet	Project Number: 11B6 Project Name: Vault Rebuilds Project Driver: SAF

Project Title:	Vault Transformer Replacements
Project Manager:	Jagoda Borovickic
Project Tech.:	Jamie Macpherson
Supporting Reference Material	OEB Audits conducted by field staff

Description

Through the course of their regular inspections, London Hydro staff have identified various indoor transformer vaults that require attention. The following vaults have been identified to be replaced in 2011:

Rick Hansen Public School
This public school vault contains oil filled transformer (non-PCB). This transformer will be replaced with transformers that are filled with a non-flammable fluid that is also environmentally friendly.
1, 3 & 5 Frontenac Road – Apartment Vaults
These indoor transformer vaults contain dry-type transformers that are more than forty years old. Our operation staff have identified these location as having chronic water problems that could result in equipment failure. This budget item will allow for the replacement of these transformers with padmount units outside the vaults. It will also allow for the installation and termination of secondary cables from the new padmount locations to the new disconnects inside the vaults.

COST ESTIMATE

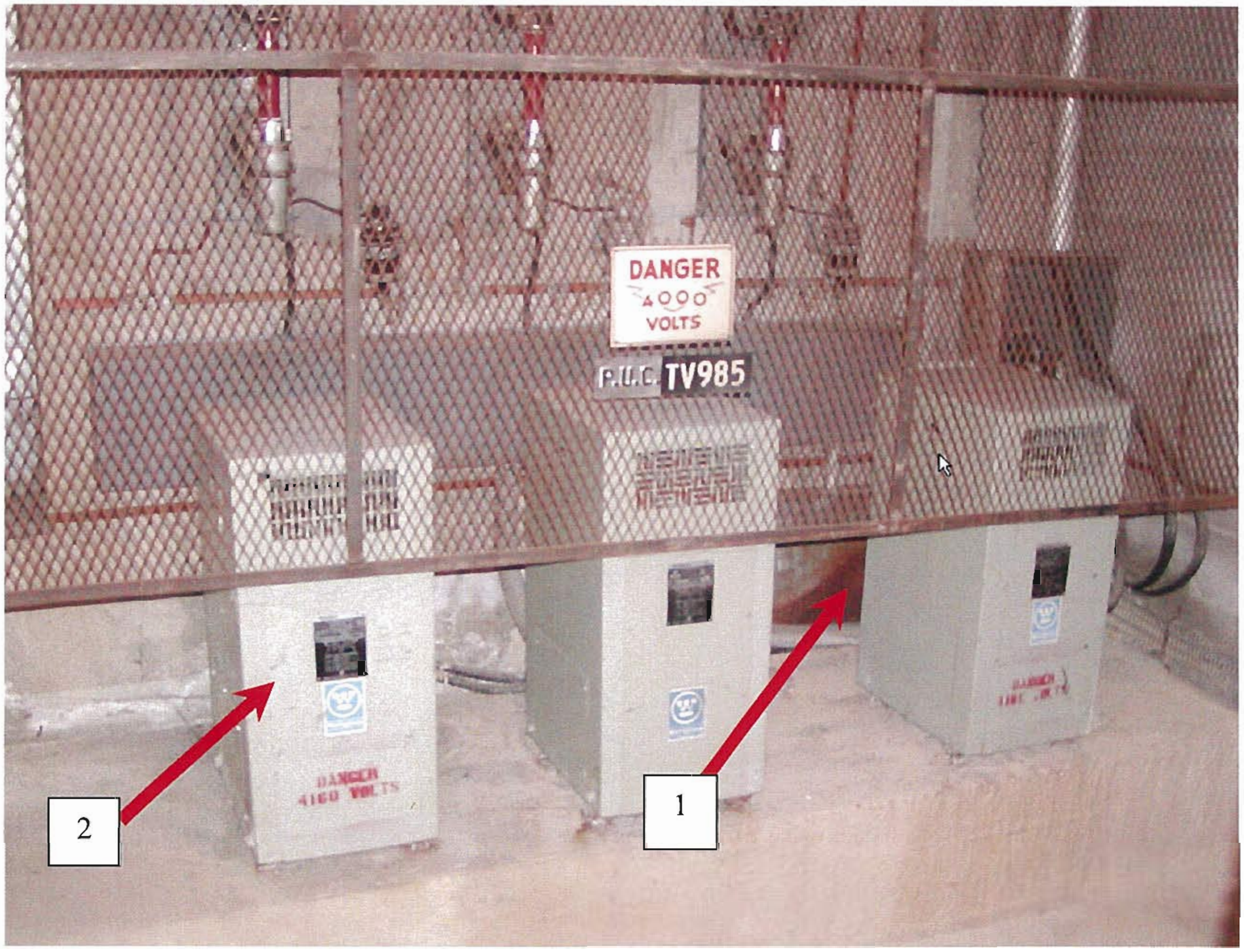
Section - 145	$250,000

Prepared By: Jagoda Borovickic, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Apartment Vault Replacements
Project 11B6

<u>5 Frontenac Road</u>



1) Advanced Corrosion due to moisture
2) Dry Type transformer

London Hydro **2011 ASSET MANAGEMENT PLAN** E&O Department		**Project Number:**	11B7
		Project Name:	Backup Supply Installation
		Project Driver:	REL
Project Title:	Installation of Underground Backup Supply		
Project Manager:	Jagoda Borovickic	**Project Tech.:**	Dane Kirilovic
Supporting Reference Material			

Description/Justification

London Hydro has started to experience outages in the Meadowbrook, Scenic View and Cleardale underground subdivisions. These areas were serviced approximately 30 years ago with a radial underground system. This configuration leaves London Hydro's control room operators with no options to restore power quickly during outages resulting from equipment failure.

This budget item provides for four radial supplies in these subdividsions (two in Cleardale Subdivision) to be "looped" thereby providing our operators with an alternate source from which they can restore power. This work will greatly improve the speed that power can be restored to these areas and enhance the reliability of supply.

COST ESTIMATE

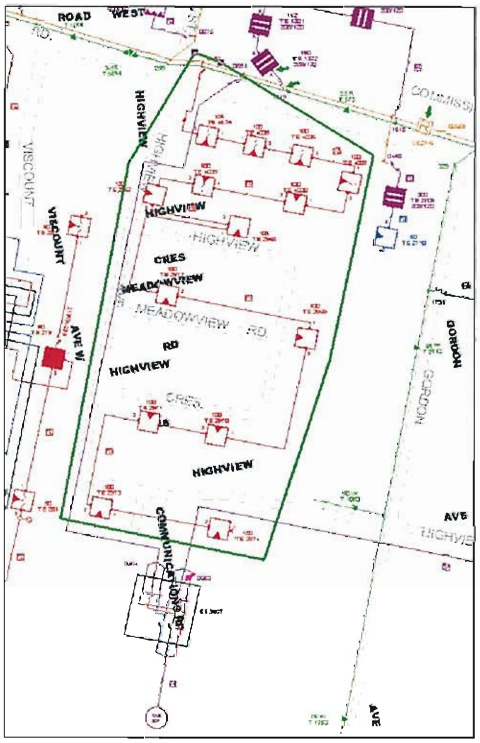
Section - 145	**$110,000**

Estimated Completion Date:	June, 2011
Prepared By:	Jagoda Borovickic, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

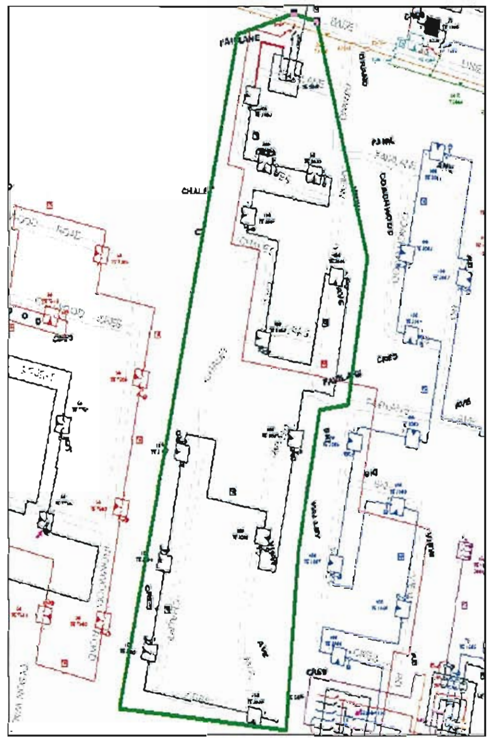
Installation of Underground Backup Supply
Project 11B7

London Hydro has started to experience outages in three underground areas that were installed approximately 30 years ago without a looped supply arrangement. As a result, cable faults within these radially supplied systems lead to prolonged outages due to the absence of switching or reconfiguration options. Each area supplies approximately 180 customers and approximately 500 kW's of load. This budget item will correct the situation by completing the loop and providing an alternate source of supply to these subdivisions. The three areas are highlighted below and are located in the Meadowbrook Subdivision and Scenic View Subdivision.

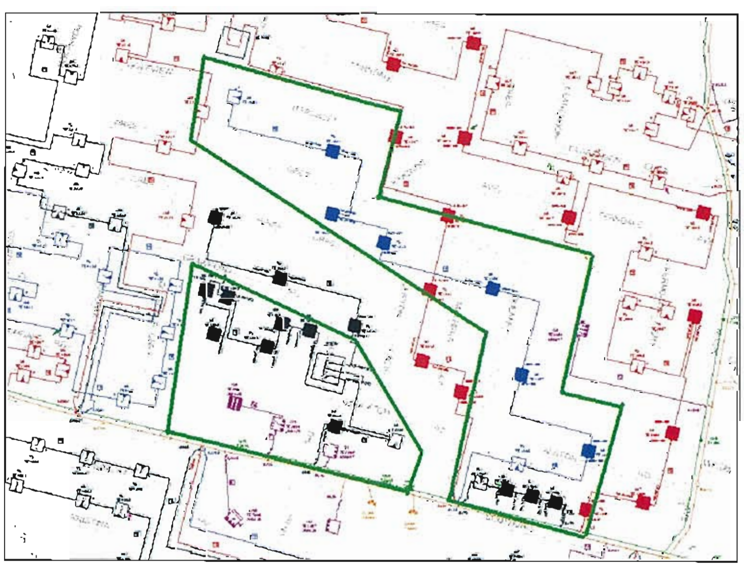
1) Meadowbrook Subdivision



2) Scenic View Subdivision



3) Cleardale Subdivision



London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:** **Project Name:** **Project Driver:**	11B8 Fault Indicator Installations REL

Project Title:	Installation of Fault Indication on Padmounted Transformers

Project Manager:	Jagoda Borovickic	**Project Tech.:**	Steve Lavell

Supporting Reference Material

Description/Justification

Fault locating of long underground systems can lead to extended outages in the absence of strategically placed fault indicators. In areas without fault indicators, our crews must open each transformer and test the cable in order to determine the location of the fault. Fault indication technology allows for fault assessment from outside of the transformer allowing our crews to quickly locate the fault, isolate the faulted cable and return power to the affected customers quickly.

This item includes the installation of fault indicators in areas with complex or lengthy underground distribution systems.

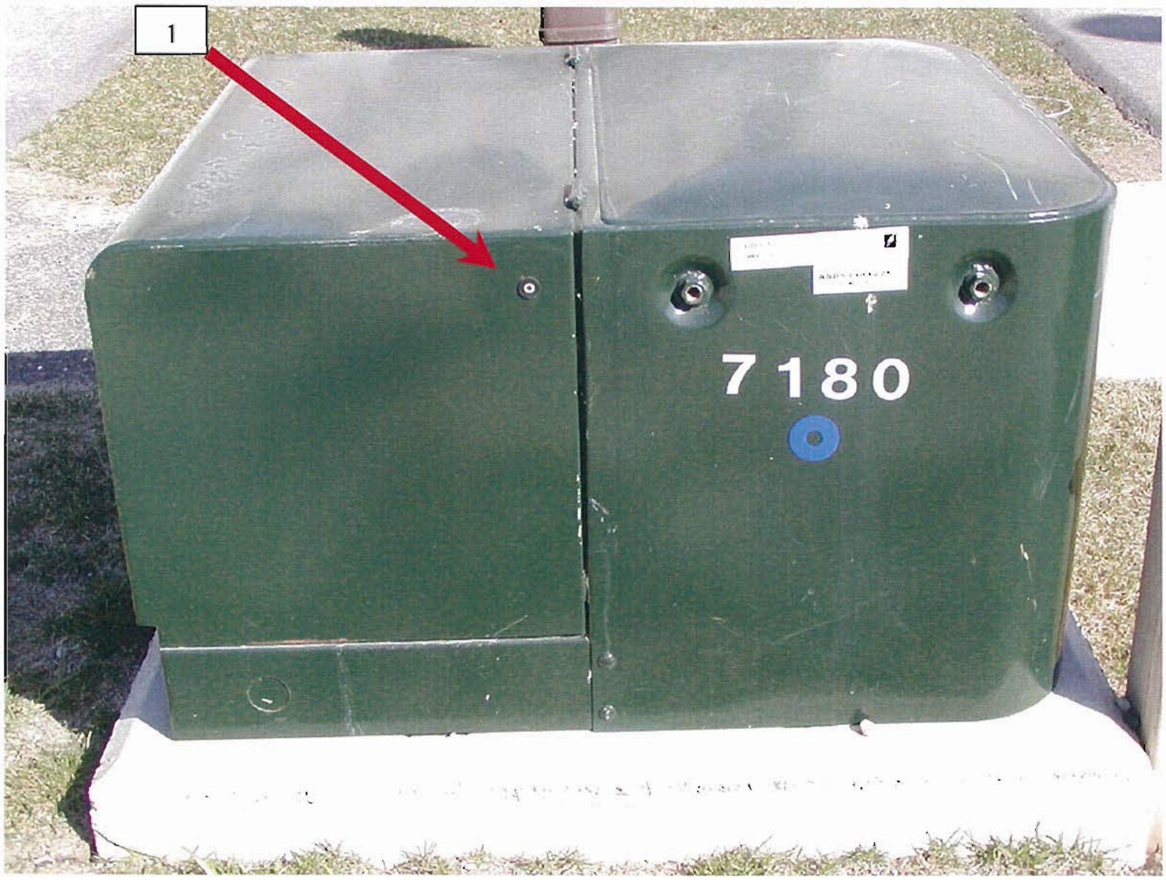
COST ESTIMATE

Section - 145	**$10,000**

Prepared By:	Jagoda Borovickic, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

Installation of Fault Indication on Padmounted Transformers
Project 11B8

As was mentioned prior, the installation of fault indication in areas with lengthy and complex circuit arrangements has the ability to decrease both outage duration and cost of repair. The average underground subdivision contains 16 transformers on a feeder loop. These loops are segmented into two radial sections of 8 transformers to minimize the effects of an outage. Through the installation of fault indication it was found that the average time required to locate a faulted section of cable could be reduced by 1.25 hrs. This translates into a savings of roughly 9600 customer minutes per outage.



1) Fault Indicator – Led lights red when transformer has witnessed fault current.

2011 ASSET MANAGEMENT PLAN E&O Department	**Project Number:**	11C1
London Hydro	**Project Name:**	Ridout 13.8 kV Conversion
	Project Driver:	RNF

Project Title: Ridout Street 13.8 kV Voltage Conversion

Project Manager: Jagoda Borovickic | **Project Tech.:** Jamie Macpherson

Supporting Reference Material

Description/Justification

London Hydro's 13.8 kV 1K4 feeder supplies several customer owned substations along Ridout Street from Dundas Street to King Street. These customer owned substations are supplied through London Hydro owned high voltage metal clad switches that are located within the customer's building. These switches are approximately 30 years old and are difficult to maintain or replace in the event of a failure. Recent developments such as the Rennisance apartments have extended our 27.6 kV system along Ridout Street. This extension has provided us with an opportunity to replace these customer owned substations and switches with standard 27.6 kV padmounted transformers. This reduces our risk of a prolonged outage on this feeder. The reduction of 13.8 kV load in this area is consistent with the long range plans for Nelson TS. It may be possible to recover spare parts from these switches so that they can be used for emergency purposes at other locations on our system.

It is noted that there are several details associated the customer owned equipment within the buildings that must be verified during the detailed design phase of this project. This will be done with the use of external consulting engineers. In absence of this detail we have used all available information to produce this budget value.

COST ESTIMATE

Section - 131	**$350,000**

Prepared By: Jagoda Borovickic, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

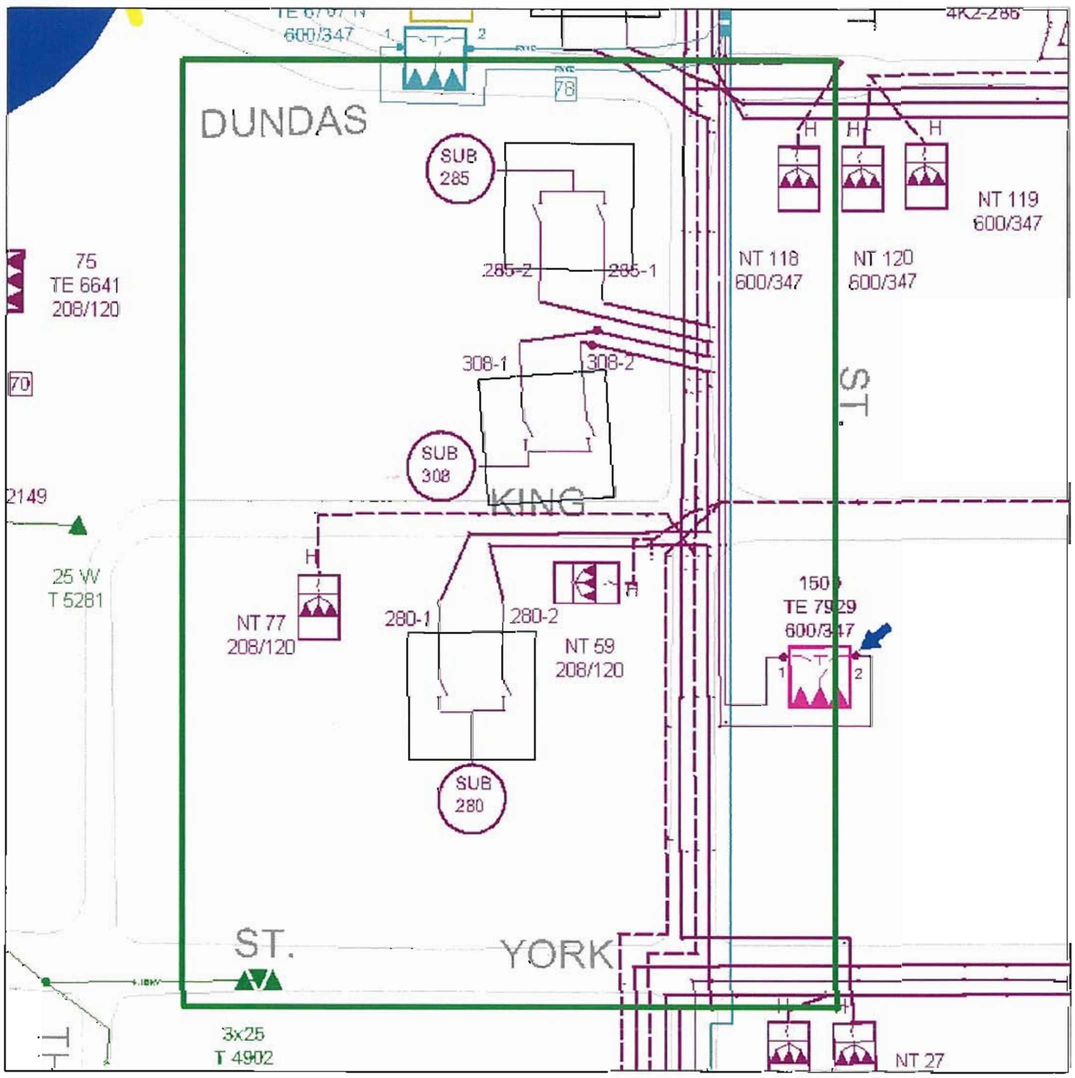
Ridout Street 13.8 kV Voltage Conversion
Project 11C1

The area targeted conversion includes the Middlesex County Court House Restoration, Middlesex-London District Health Unit building and the Peter McGregor Apartments building. The London Art Gallery was converted in 2010.

The reduction of 13.8 kV in this area is consistent with the long range plans for Nelson TS. This project will also help to facilitate the future elimination of an obsolete oil switch located at Bathurst and Ridout Streets along with two 13.8 kV station breakers.

This conversion will transfer all load that is directly supplied by the 1K4 feeder to the 27.6 kV system. The overall area being converted is illustrated below and represents approximately 1.5 MW of load.

Conversion Area Along Ridout Street



2011 ASSET MANAGEMENT PLAN
E&O Department

London Hydro

Project Number:	11C2
Project Name:	26M43 Phase 1
Project Driver:	RNF

Project Title: 26M43 Feeder Construction Phase 1

Project Manager: Rod Doyle

Project Tech.: Hank Bonnar

Supporting Reference Material

New Supply Capacity for London - 2006 to 2010
2008 Addendum to New Supply Capacity for London 2006-2010

Description/Justification

Due to the growing load in the northwest section of the City, London Hydro requires increased load transfer capability in this region.

London Hydro has inadequate conductor size along Hyde Park Rd. between Sarnia Rd. to Fanshawe Park Rd. limiting transfer capabilty from Oxford to Fanshawe Park Rd. Constructing an improved circuit along Hyde Park Rd. is not feasible at this time until the City of London widens Hyde Park Rd. starting in 2015.

An alternative to resolve the transfer capability in this area is to build part of the future 26M43 feeder that was identified in the *New Supply Capacity for London* 2006 - 2010 reports. The construction of this partial feeder is along Sarnia Rd. between Wonderland Rd. and Hyde Park Rd. This will create a new feeder tie between the 26M55 to the 26M54 and splitting the distance for load transfer on Hyde Park Rd.

The CN rail crossing will be framed for a future feeder that was also identified in the *New Supply Capacity for London* 2006 - 2010 reports.

COST ESTIMATE

Section - 131	**$300,000**

Prepared By: Rod Doyle, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

26M43 Feeder Construction Phase 1

Project 11C2

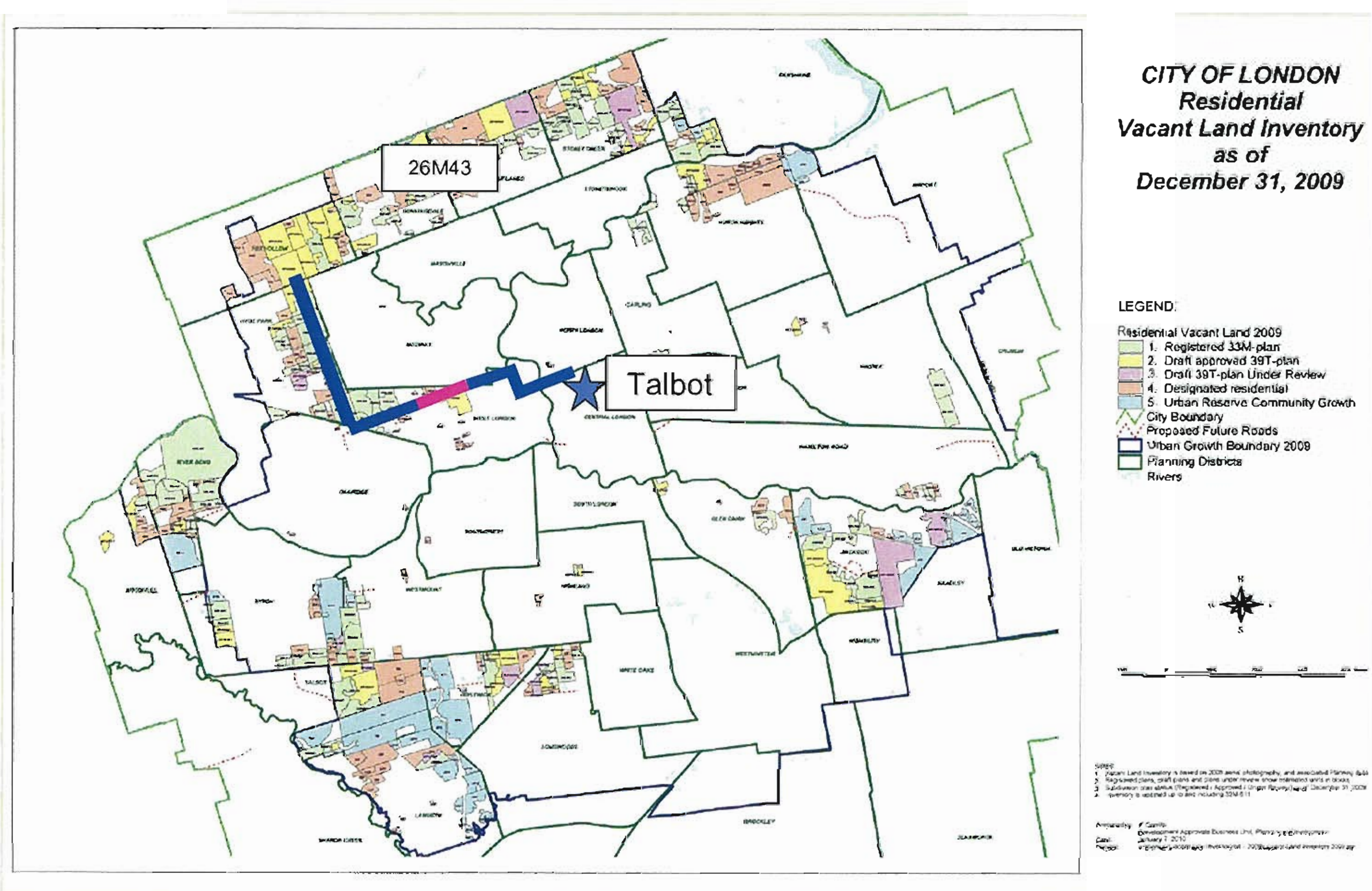
The scope of the work involves extending the pole line on Sarnia Rd. between Aldersbrook Road, over the CN rail right-of-way to Oakcrossing Gate. This construction will create a new feeder tie between the 26M55 and 26M54.

The remaining phases of 26M43 will be constructed later, when required. The completion of the 26M43 feeder will supply the northwest corner of the city.

26M43 Feeder – Phase 1

26M43 Feeder

Feeder Route for the 26M43 Feeder



London Hydro	2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11C3
		Project Name:	4M15 Extension
		Project Driver:	RNF

Project Title:	4M15 Feeder Extension

Project Manager:	Rod Doyle	**Project Tech.:**	Jim Soetemans

Supporting Reference Material	New Supply Capacity for London - 2006 to 2010 2008 Addendum to New Supply Capacity for London 2006-2010

Description/Justification

System Planning has identified the need to provide load transfer capability between Highbury TS and Buchanan TS along the east corridor of the City where most of the industrial load is locatied and to provide backup for the Innovation Industrial Park.

This project involves extending the 4M15 feeder along Veteran's Memorial Parkway, from River Rd. to Hamilton Rd. This feeder extension was identified in the *New Supply Capacity for London* 2006 - 2010 reports

COST ESTIMATE

Section - 140	**$440,000**

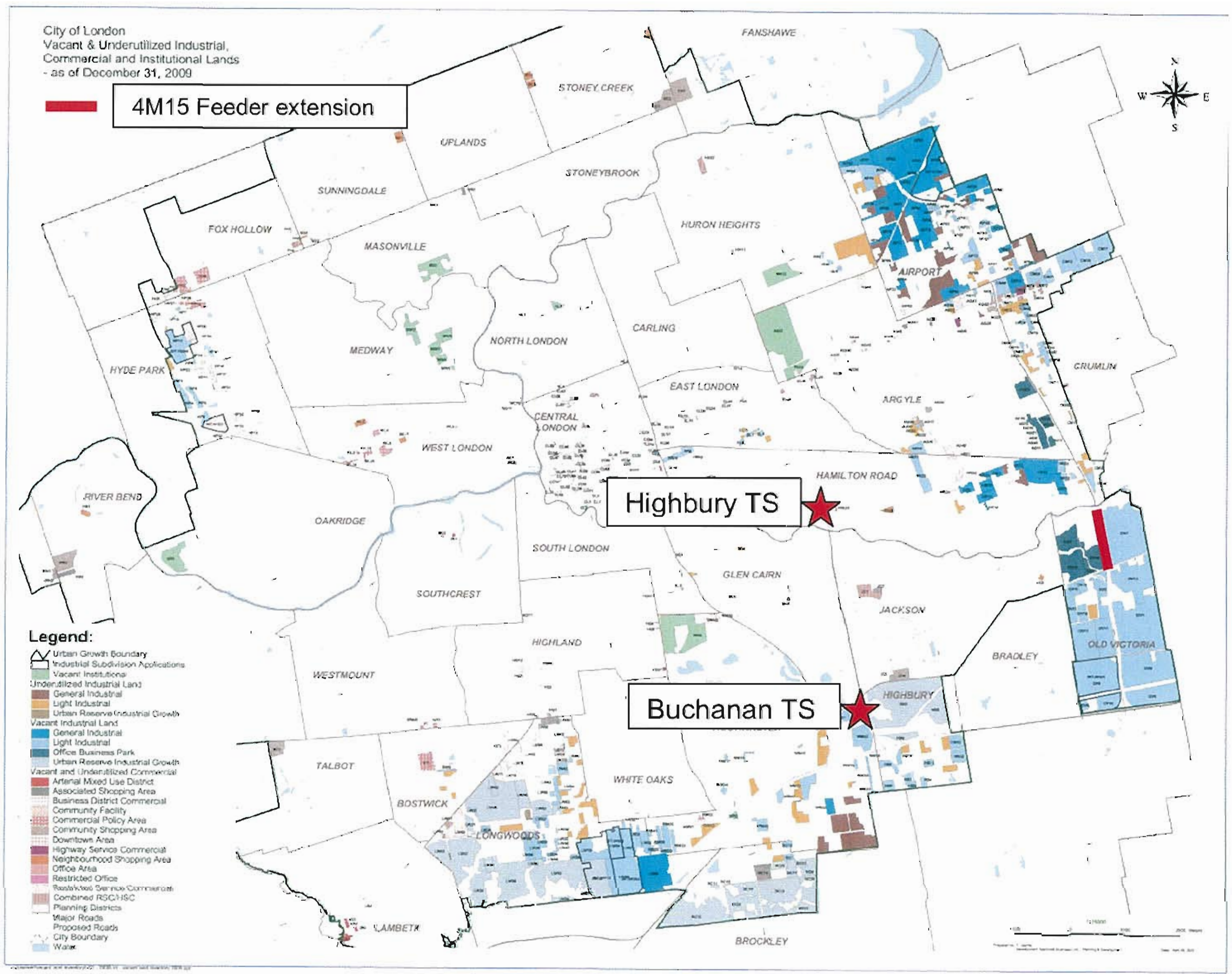
Prepared By:	Rod Doyle, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

4M15 Feeder Extension

Project 11C3

London Hydro will construct the 4M15 feeder extension along Veterans Memorial Parkway from River Road to Hamilton Road to supply backup to the City of London's Innovation Industrial Park and to provide backup contingency between Highbury TS and Buchanan TS along the east corridor of the City.

Feeder Extension for the 4M15 Feeder



London Hydro — 2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11C4
	Project Name:	Crumlin Road Reinforcement
	Project Driver:	RNF

Project Title:	Crumlin Rd. Feeder Upgrade and 8.32kV Voltage Conversion
Project Manager:	Rod Doyle
Project Tech.:	Jim Soetemans
Supporting Reference Material	

Description/Justification

The northeast area of the city inlcuding the London Airport is supplied by Clarke T.S. At present there is limited transfer capability between Highbury TS and Clarke TS. This is due to a circuit with undersized conductor along the easterly boundary of the City. New industrial growth in this area has increased the need for this circuit to be rebuilt to present 556kcmil 600A, 27.6kV standards. This build will ensure adequate backup capacity for the airport and the new industrial load in this area.

There is also a dual pole line (27.6kV on west side, 8.32kV on east side) on Crumlin Side Road. This build will facilitate the conversion of the older 8.32kV pole line, improving aesthetics and reducing losses

COST ESTIMATE

Section - 140	**$860,000**

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Crumlin Rd. Feeder Upgrade and 8.32kV Voltage Conversion
Project 11C4

This project is required to reinforce a circuit that runs along the eastern city limits on Crumlin Side Road between Trafalgar Street and Page Street. Installing 556kcmil conductor on the existing 27.6kV insulated poles will increase the load transfer capability between Highbury TS and Clarke TS. The project will also eliminate an 8.32kV circuit, thereby reducing system losses and improving aesthetics. This project will improve supply security for a number of industrial customers including the London International Airport.

London Hydro **2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:** 11C5 **Project Name:** 26K6 Voltage Conversion **Project Driver:** RNF

Project Title:	Sub 26 and 46 13.8kV Voltage Conversion		
Project Manager:	Rod Doyle	**Project Tech.:**	Hank Bonnar
Supporting Reference Material			
Description/Justification	Convert the 13.8kV circuit 26K6 to 27.6kV at all locations east of Rectory Street to Highbury Avenue along Dundas and Florence. Portions of the circuit are already framed, conductored and insulated for 27.6kV conversion. The 26K6 is an older radial feeder that is backed up through a local 27.6/13.8kV step down transformer. EMCO transferred their load to 27.6kV leaving the former McCormick's plant as the only remaining significant load on this 13.8kV section and this facility has now closed.		

COST ESTIMATE

Section - 140	**$240,000**

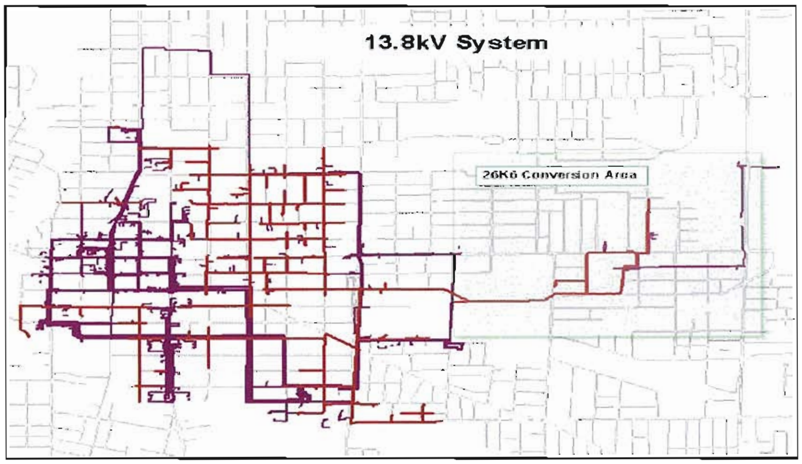
Prepared By: Cole Tavener
Assistant Distribution Engineer

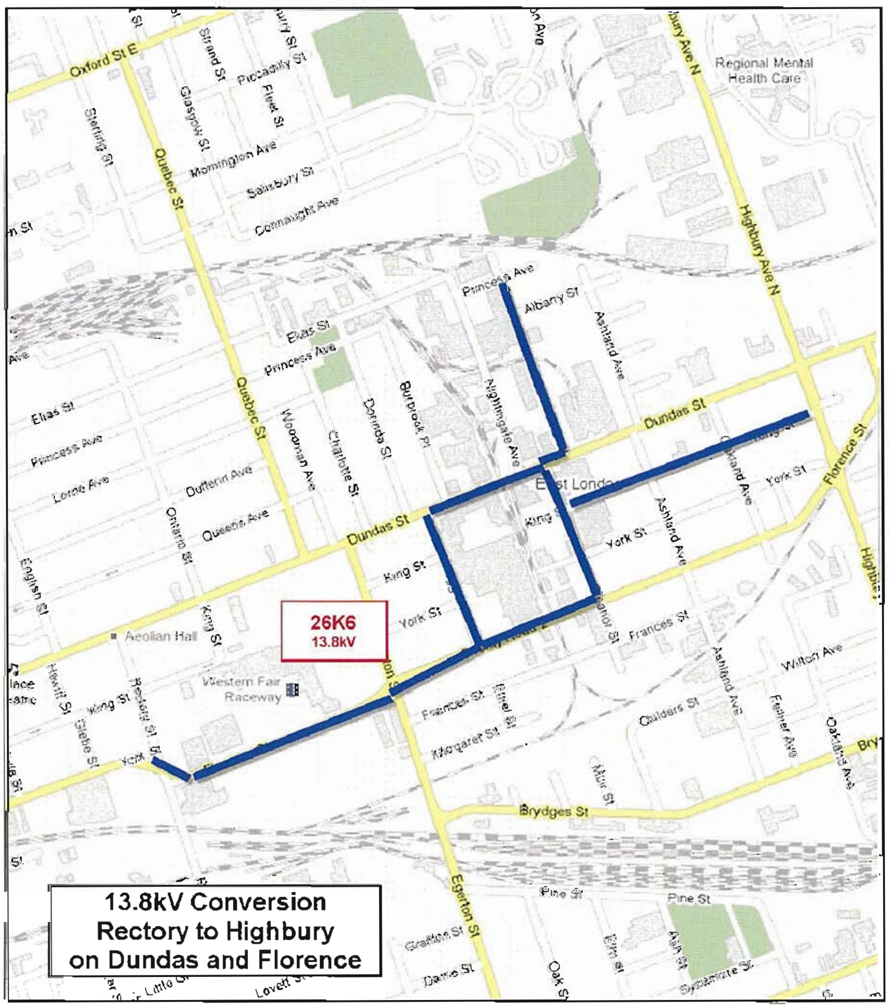
Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Sub 26 and 46 13.8kV Voltage Conversion

Project 11C5

The 26K6 is an aging radial feeder tapped off of the main 13.8kV distribution system. Backup has been provided through a local 27.6/13.8kV step down transformer. The recent transfer of EMCO load to the 27.6kV system and the demise of McCormick's has resulted in very little remaining 13.8kV load on this 2km long, radial circuit. Converting the remaining load will eliminate the need for both Substation 26 and Substation 46. Rebuilding the feeder at 27.6kV also aligns with future plans to connect load to the planned 27.6kV Nelson TS.





2011 ASSET MANAGEMENT PLAN **E&O Department**	**Project Number:**	11D1
	Project Name:	City Requested Relocations
	Project Driver:	COL

London Hydro

Project Title:	City of London (Road Authority) Relocations

Project Manager:	Rod Doyle	**Project Tech.:**	Hank Bonnar & Jim Soetemans

Supporting Reference Material

Description/Justification

This project comprises of the relocation of London Hydro Infrastructure located on the road allowance. These relocations are initiated by the Road Authority (City of London) and are necessary in order to accommodate planned modifications to the roadway.

The terms and conditions under which these relocations occur are specified in the Public Service Works on Highways Act enacted by the Provincial Government. The Act gives a Road Authority the power to ensure that all operating corporations entitled to the use of the road allowance cooperate with the Road Authority to execute any required modifications to the profile of the road allowance in a timely manner. The Act states that an Operating Corporation (London Hydro Inc) must modify or relocate their plant on the road allowance to accommodate the Road Authority's improvements or alterations within a specified time period. The Act also outlines the mechanism for the apportionment of costs for these required works. Typically the Operating Corporation is permitted to recover 50% of the labour and vehicle costs from the Road Authority.

Some of the known relocation projects for 2011 include:
- Fanshawe Park Rd. and Highbury Ave. intersection widening
- Quebec St. north of Dundas

COST ESTIMATE

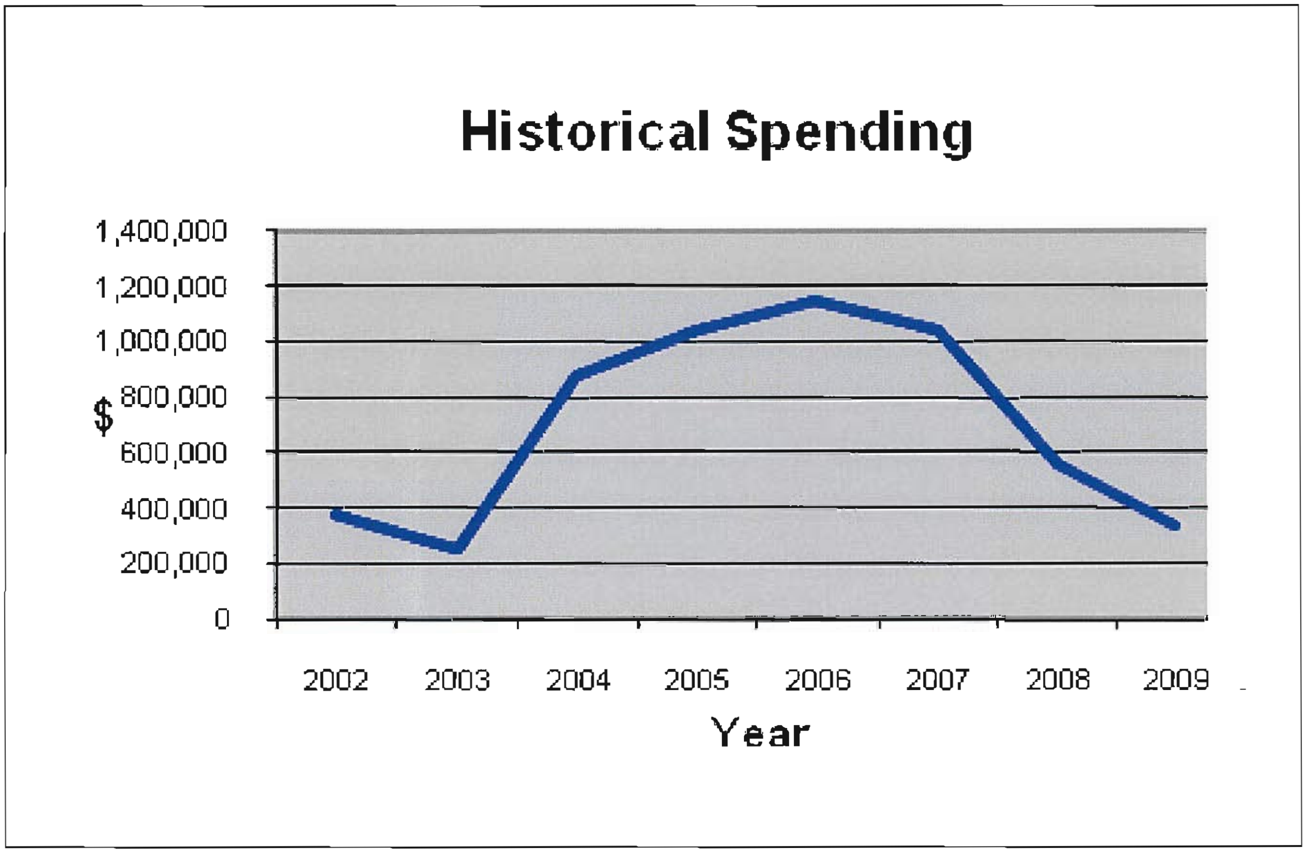
Section - 133	**$500,000**

Prepared By:	Rod Doyle, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

City of London (Road Authority) Relocations
Project 11D1

London Hydro works closely with the City of London to try to determine which of their projects will affect London Hydro's infrastructure. Unfortunately, the City has not defined all their projects for 2011; therefore, the annual expenditures are estimated based on a combination of known projects and base historical spending. Spending in this area has ranged from $249,000 to $1,140,000 in the last seven years depending on the projects that were identified by the City of London as being required.

The City of London has one large relocation for 2011, which was deferred from 2010, at Fanshawe Park Rd. and Highbury Ave. intersection widening. The other City of London relocation is on Quebec St., just north of Dundas St.



2011 ASSET MANAGEMENT PLAN
E&O Department

London Hydro

Project Number:	11E1
Project Name:	Expansions and Relocations
Project Driver:	DEV
Project Title:	Developer Driven Distribution Circuit Expansions and Relocations
Project Manager:	Jagoda Borovickic/Rod Doyle
Project Tech.:	Hank Bonnar
Supporting Reference Material	

Description/Justification

This budget item includes extension of the existing high voltage overhead or underground distribution system in order to accommodate new customer developments as they are added to London's service area. This budget item includes all costs associated with the construction of these extensions.

Some of the major expansions anticipated for 2011 include:

- Innovation Park Phase 4A (underground)
- Talbot Street - Dufferin to Carling, Carling Street - Talbot to Richmond and Richmond Street - Carling to Fullarton (underground)
- Commissioners Road East - Hosptial Entrance (overhead)
- Richmond Street - north of Sunningdale Road and on Sunningdale Road - west of Richmond Street (overhead)

This item also includes the relocation of existing London Hydro plant for accommodating new developments within the city limits. These relocations are required when items such as new proposed driveways and turn lanes for new developments are in conflict with the existing hydro plant. This budget item includes all costs associated with the relocation.

COST ESTIMATE

Section - 131	**$830,000**

Prepared By:	Jagoda Borovickic, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

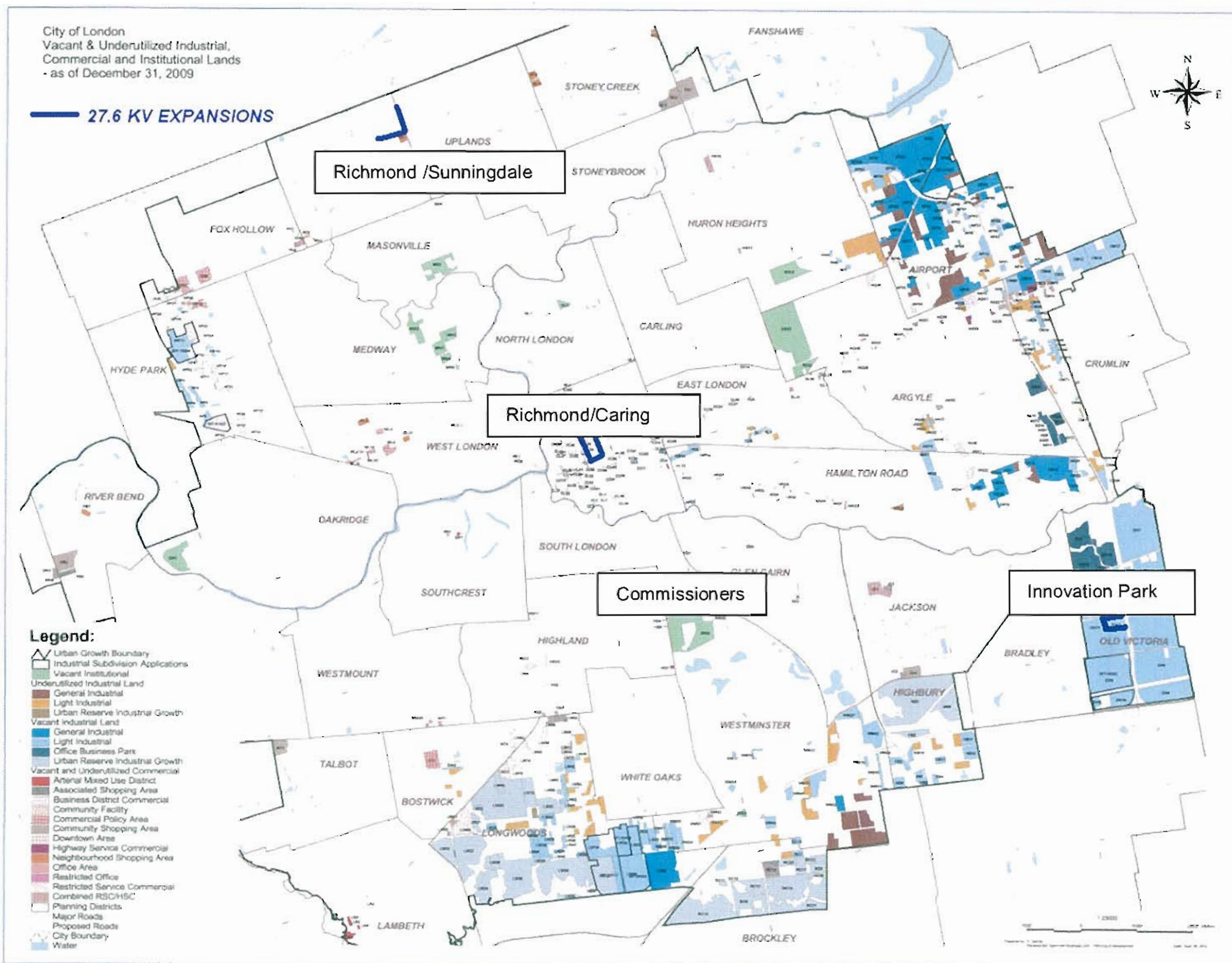
Developer Driven Distribution Circuit Expansions and Relocations
Project 11E1

This project comprises the installation and/or modification of electrical equipment that is used in supplying customers' installations. It also includes the work associated with upgrading existing installations.

The London Hydro Conditions of Service Document details how capital contributions are assessed for these installations.

From a budgeting perspective, the annual expenditures are estimated based on a number of factors including: City of London development forecasts and customer inquiries.

The four expansions that are proposed for 2011 include: Innovation Park Phase 4A, expansions for a new development at the northwest corner of Richmond Street and Carling Street and at the northwest corner of Richmond Street and Sunningdale Road, and a relocation on Commissioners Road to accommodate a new hospital entrance. These expansions are illustrated on the map below. These four expansions account for $530,000. The remaining $300,000 allocated for expansions and relocations is yet to be determined by various developers.



2011 ASSET MANAGEMENT PLAN

E&O Department

London Hydro

Project Number:	11E2
Project Name:	Secondary Service Upgrades
Project Driver:	DEV

Project Title:	Residential Secondary Service Upgrades		
Project Manager:	Rod Doyle	**Project Tech.:**	Jim Soetemans
Supporting Reference Material			

Description/Justification

This budget item includes replacement of the existing low voltage conductors with conductors of increased size from the overhead transformer to the customers' electrical service stacks. These upgrades are often required when customers increase their electrical demands. This item involves all costs associated with these upgrades.

COST ESTIMATE

Section - 131	**$324,000**

Prepared By:	Jagoda Borovickic, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

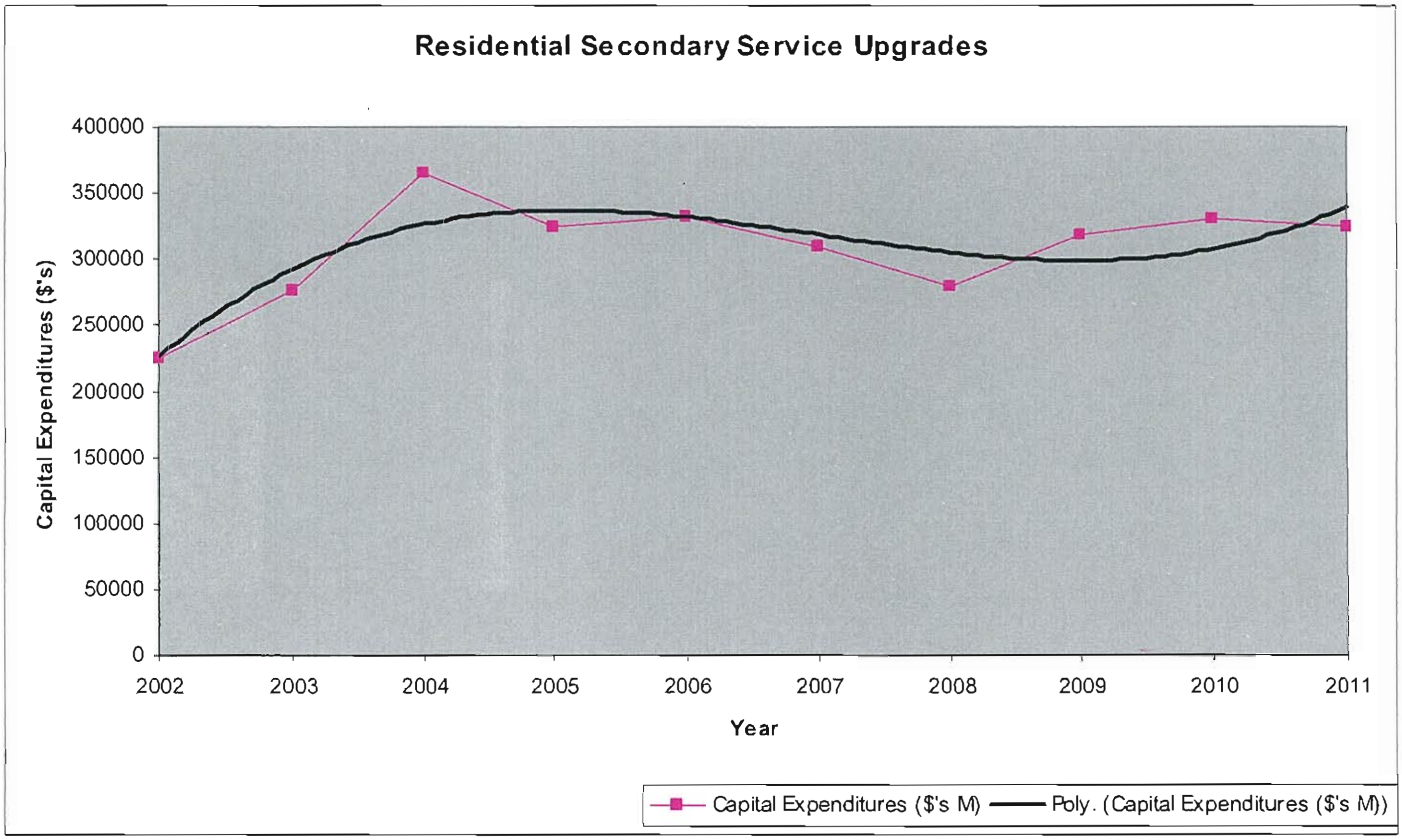
Residential Secondary Service Upgrades

Project 11E2

This project comprises the replacement of overhead low voltage electrical services to residential dwellings. There is no charge to customers for these upgrades as they are part of London Hydro's basic connection for overhead residential customers as defined in the Distribution System Code.

These upgrades are initiated by customers that require an increase to their electrical service size. These requests may be due to issues such as the addition of new load in their home or due to requirements of an insurance company that requires the service to be upgraded to a minimal size and configuration.

From a budgeting perspective, the annual expenditures are estimated based on past history. A graph has been provided below and illustrates the level of required expenditures within London Hydro's service territory.



2011 ASSET MANAGEMENT PLAN **E&O Department**	**Project Number:**	11E3
	Project Name:	Residential Underground
	Project Driver:	DEV

Project Title:	New Single Family Residential Underground Distribution
Project Manager:	Jagoda Borovickic
Project Tech.:	Jamie Macpherson
Supporting Reference Material	

Description/Justification

This item involves the installation of single family residential underground distribution systems to provide service as needed to developers. We are budgeting $1,600,000 for 2011 based on a number of factors including the forecast by the Canada Mortgage and Housing Corporation.

It is noted that market conditions can create large fluctuations in expenditures from year to year. This item is solely dependant on market conditions. This section will contain several different projects of varying magnitude depending on customer requirements.

COST ESTIMATE

Section - 142	**$1,600,000**

Prepared By: Jagoda Borovickic, P.Eng
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Residential Underground

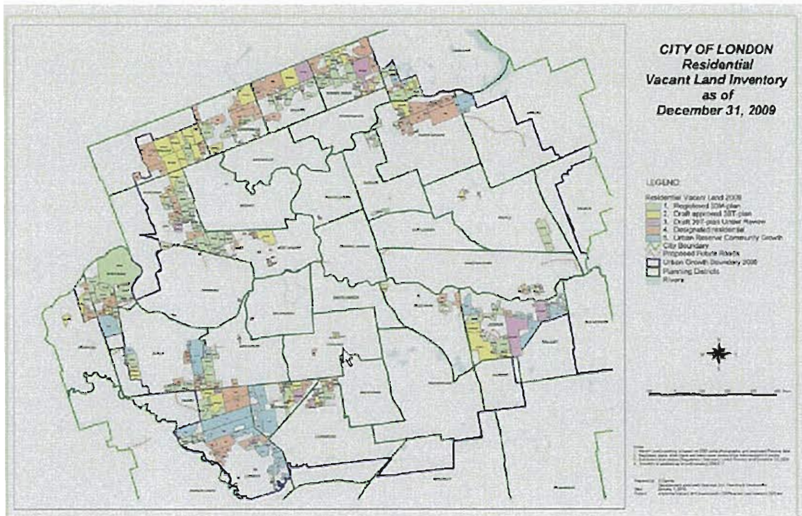
Project 11E3

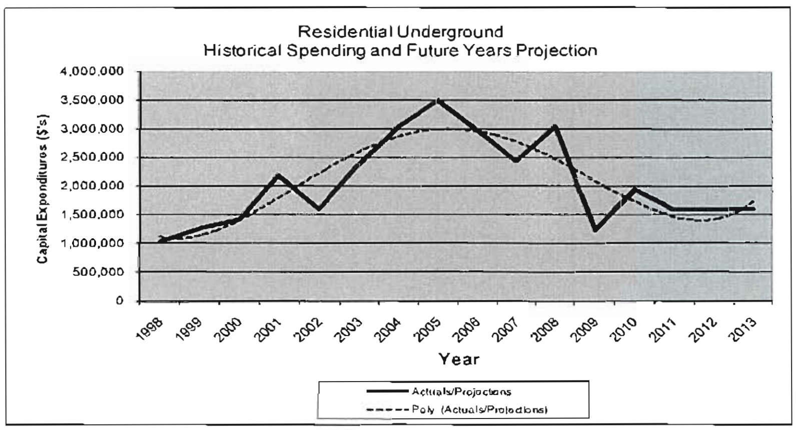
This project involves the installation of single family residential underground distribution systems to provide service as needed to developers.

The London Hydro Conditions of Service Document details how capital contributions are assessed for these installations.

From a budgeting perspective, the annual expenditures are estimated based on a number of factors including: past history, City of London development forecasts, market reviews including Canada Mortgage and Housing Corporation, and customer inquiries. Examples of the various documents created and reviewed are shown. This information is updated each year and the forecasts and budgets are adjusted accordingly.

This collection of information is part of a larger library that is used in the preparation of the 25 year load forecast.





Housing Market Outlook - Ontario Region Highlights - Date Released: Third Quarter 2010

Ontario Region Housing Forecast - New Construction

	Housing Starts	2009	2010(F)	% chg (2009/2010)	2011(F)	% chg (2010/2011)	YTD 2010	YTD 2009	% chg (2009/2010)
London	Single-Detached	1,056	1,600	51.5	1,300	-18.8	802	324	147.5
	Multiple	1,112	770	-30.8	840	9.1	490	628	-22.0
	Total	2,168	2,370	9.3	2,140	-9.7	1,292	952	35.7

Canada Mortgage and Housing Corporation 6

Housing Starts in London

Apartment development is included in Multihousing at CMHC, however is included in 11E5 Commercial at London Hydro.

London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:**	11E4
		Project Name:	Multi-Housing Servicing
		Project Driver:	DEV

Project Title: New Multi-Housing Underground Distribution

Project Manager: Jagoda Borovickic

Project Tech.: Jamie Macpherson

Supporting Reference Material

Description/Justification

This item is for the installation of multi-housing (primarily townhouses and condominiums) underground distribution systems to provide service as needed to developers. We have budgeted $650,000 for 2011 based on a number of factors including the forecast by the Canada Mortgage and Housing Corporation.

This item is solely dependant on market conditions. This section will contain several different projects of varying magnitude depending on customer requirements.

COST ESTIMATE

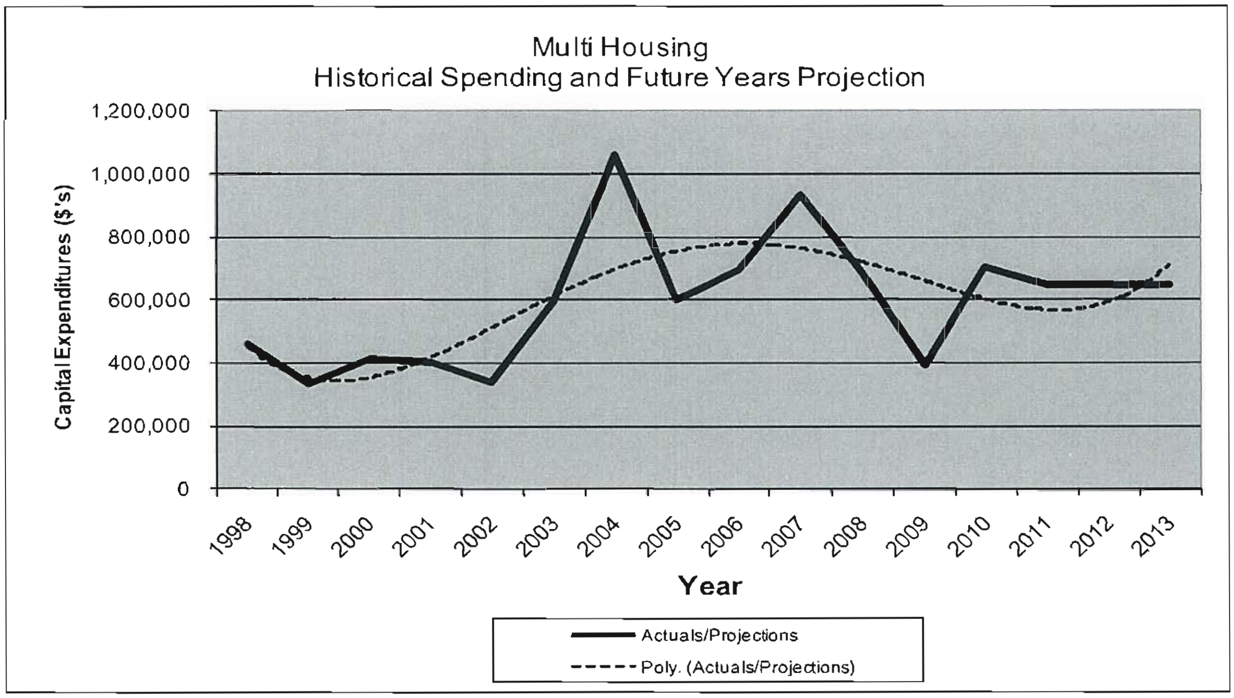
Section - 143	**$650,000**

Prepared By: Jagoda Borovickic, P.Eng
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Multi Housing
Project 11E4

This project involves the installation of multi housing underground distribution systems to provide service as needed to developers.



The London Hydro Conditions of Service Document details how capital contributions are assessed for these installations.

From a budgeting perspective, the annual expenditures are estimated based on a number of factors including: past history, City of London development forecasts, market reviews including Canada Mortgage and Housing Corporation, and customer inquiries. Examples of the various documents created and reviewed are shown. This information is updated each year and the forecasts and budgets are adjusted accordingly.

This collection of information is part of a larger library that is used in the preparation of the 25 year load forecast.

Housing Market Outlook - Ontario Region Highlights - Date Released: Third Quarter 2010

Ontario Region Housing Forecast - New Construction

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Canada Mortgage and Housing Corporation 6

Housing Starts in London

Apartment development is included in Multihousing at CMHC, however is included in 11E5 Commercial at London Hydro.

London Hydro — **2011 ASSET MANAGEMENT PLAN** E&O Department	**Project Number:** 11E5 **Project Name:** Commercial Distribution **Project Criver:** DEV
Project Title:	New Commercial Distribution Services
Project Manager: Jagoda Borovickic	**Project Tech.:** Albert Kanters/Dane Kirilovic
Supporting Reference Material	

Description/Justification

This item is for the installation of commercial overhead and underground distribution systems to provide service as needed to customers. We have budgeted $2,100,000 for 2011. This item is solely based on market conditions.

This budget is based on past historical expenditure patterns.

COST ESTIMATE

Section - 144	**$2,100,000**

Prepared By: Jagoda Borovickic, P.Eng
Distribution Engineer

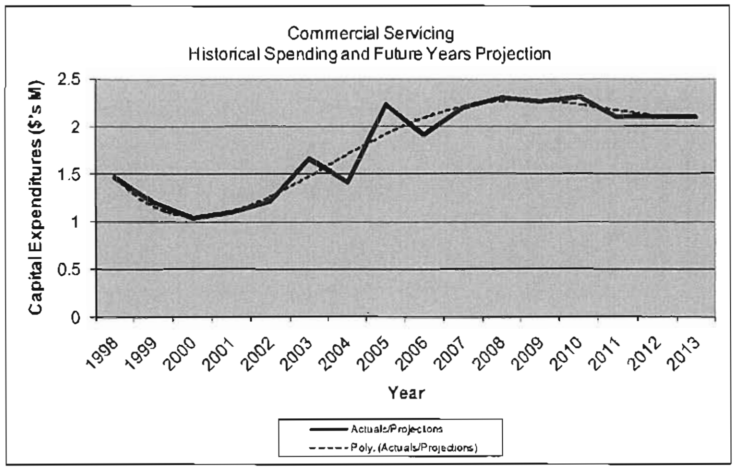
Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Commercial Distribution
Project 11E5

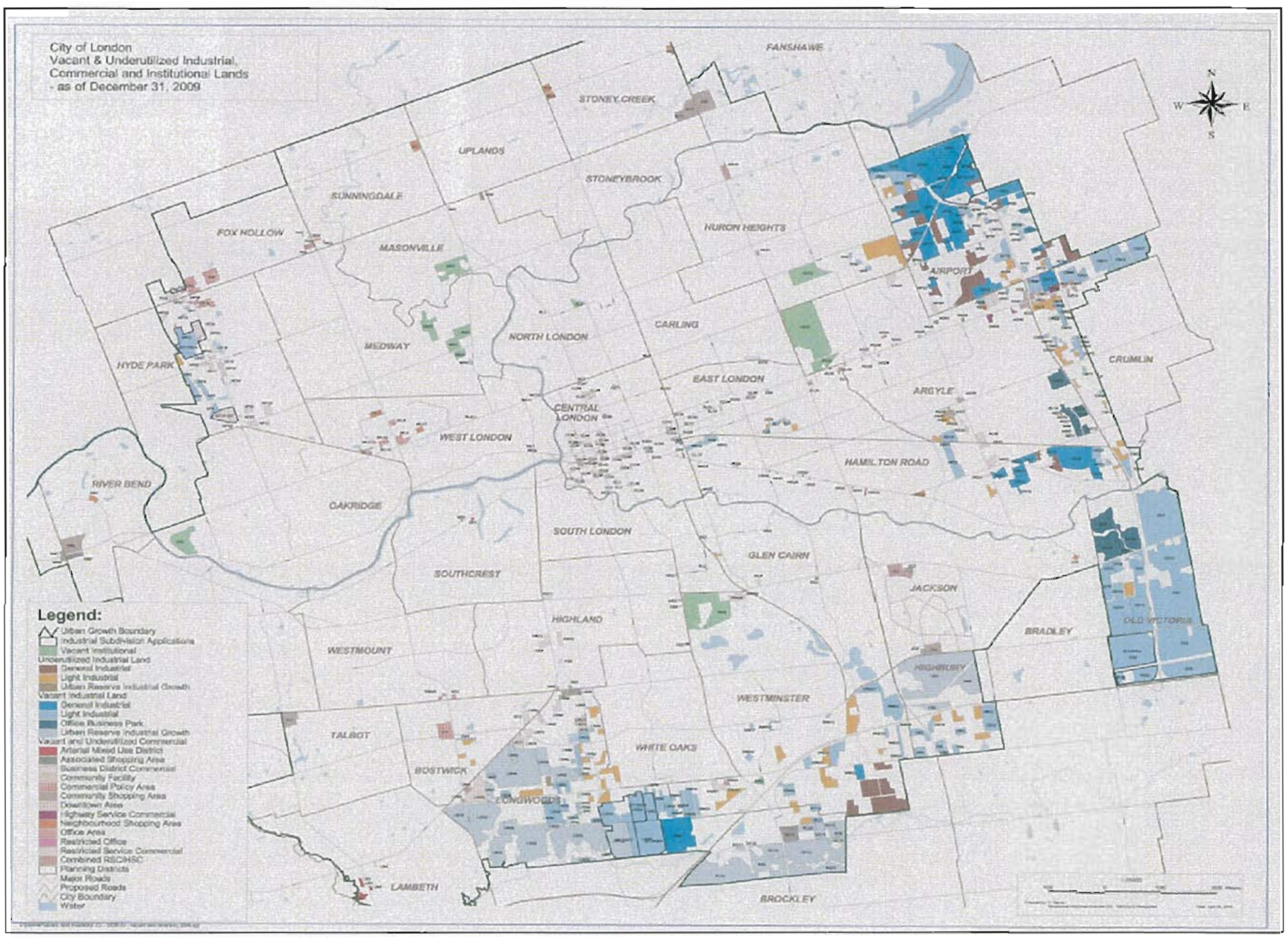
This project comprises the installation and/or modification of electrical equipment that is used in supplying commercial (including apartments) and industrial customers' installations. It also includes the work associated with upgrading existing installations.

The London Hydro Conditions of Service Document details how capital contributions are assessed for these installations.

From a budgeting perspective, the annual expenditures are estimated based on a number of factors including: past history, City of London development forecasts, market reviews, and customer inquiries. Examples of the various documents created and reviewed are shown. This information is updated each year and the forecasts and budgets are adjusted accordingly.



This collection of information is part of a larger library that is used in the preparation of the 25 year load forecast.



London Hydro **2011 ASSET MANAGEMENT PLAN** E&O Department	**Project Number:** 11F1 **Project Name:** Network Vault/Manhole/Tx Replacements **Project Driver:** SAF

Project Title:	Replacement of Network Vaults/Manholes/Transformers		
Project Manager:	Jagoda Borovickic	**Project Tech.:**	Jamie Macpherson
Supporting Reference Material			

Description/Justification

This item involves the design and installation of structural entities such as concrete manholes, vaults, roof slabs and steel vault grating at various locations.

The condition of the above items is monitored through inspections by a structural engineer and our operations staff. This item is used to resolve all safety and reliability issues resulting from these inspections.

A part of this budget is allocated for completing some projects that were not completed in 2010. Due to the high customer demand that caused shortage in the construction resources, we were not able to complete all projects that were approved in the same area on 2010 Asset Management Plan.

COST and TIMING ESTIMATES

Section - 141	**$1,320,000**

Prepared By: Jagoda Borovickic, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operation

Replacement of Network Vault/Manhole/Transformers

Project 11F1

Each year, London Hydro's operations staff conduct inspections of the London Hydro subsurface chambers on a scheduled basis. These inspections are carried out in compliance with the requirements of the Distribution System Code. During the course of these inspections, notes are made to identify all structures that require additional assessment by a Professional Structural Engineer. The structural engineer then provides direction on the appropriate course of action that is required (if any) to maintain the structural integrity and safety of the installation.

The structural engineer's findings are documented and then implemented within the timelines that are specified. Typical findings involve delamination of concrete roof slabs and walls. This can be due to numerous factors including aggregate composition, salt contamination, age and method of construction used at the time. The picture below illustrates a deteriorated roof slab of a network transformer vault.

Sample of a Vault Roof slab in need of Replacement

London Hydro **2011 ASSET MANAGEMENT PLAN** E&O Department		**Project Number:**	11F2
		Project Name:	Primary/Secondary Cable Replacements
		Project Driver:	REL
Project Title:	Replacement of Primary and Secondary Cables		
Project Manager:	Jagoda Borovickic	**Project Tech.:**	Scott Lasseter
Supporting Reference Material			

Description/Justification

Over the years some of the cables in our distribution system have lost their ability to carry full load current and in some cases their dielectric strength has been compromised. This is partially due to age and loading conditions. These sections are often hard to detect until the quality of power is compromised. The degree of the problems can range from low voltage problems to power outages.

When these cables are identified, they are replaced with cables that meets our present day specifications and standards.

This budget item will include the replacement of primary and secondary cables which have reached failure or are approaching the end of their useful service life.

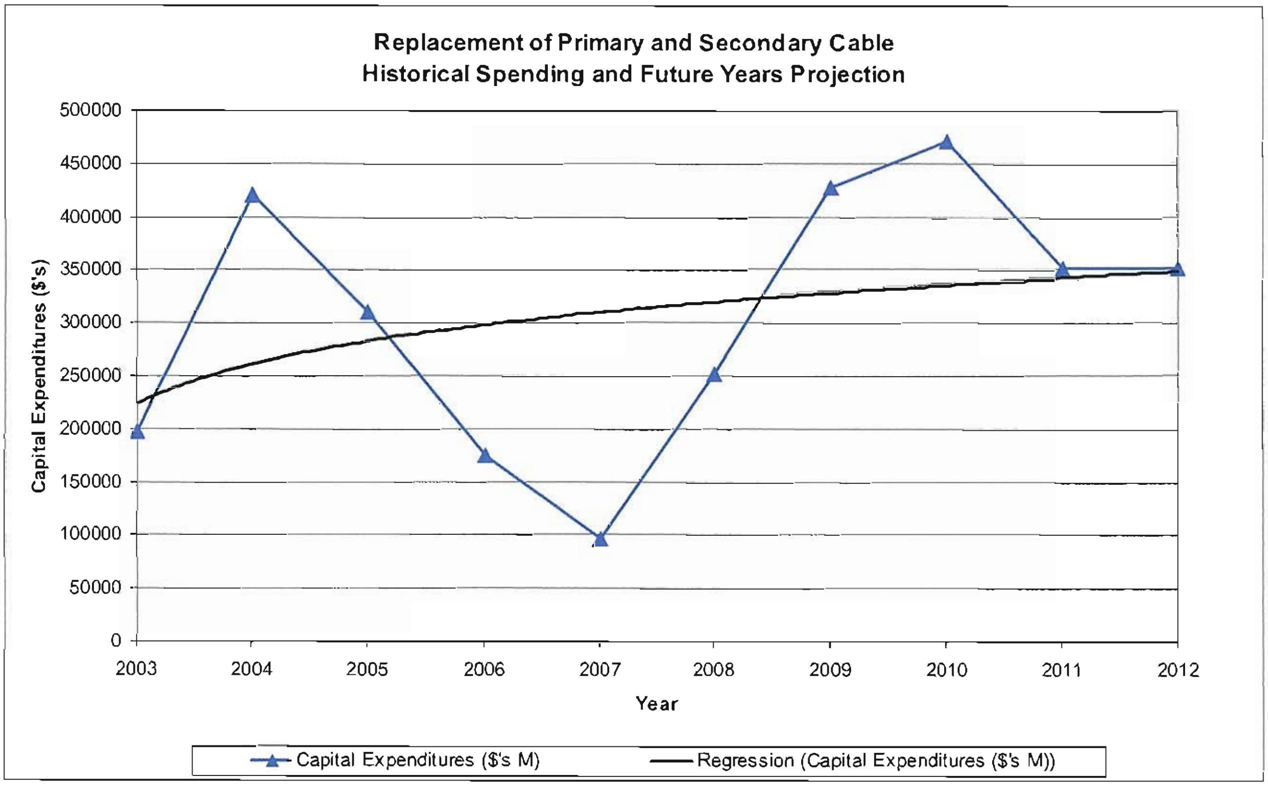
COST ESTIMATE

Section - 150	**$350,000**

Prepared By:	Jagoda Borovickic, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

Replacement of Primary and Secondary Cables
Project 11F2

London Hydro has approximately 1700 km of primary cable in our distribution system and 25 km of low voltage main secondary cable in our downtown core. Although London Hydro is continuously assessing and replacing these cables through identified capital projects, some cables fail unexpectedly and require replacement. This budget item provides for replacement of these cables. Due to the fact that these failures are unplanned, a historical trend is used to estimate the required level funding for the replacements. The graph below illustrates that expenditures have been as high as $470,000 and as low as $100,000.



London Hydro	2011 ASSET MANAGEMENT PLAN E&O Department	Project Number: Project Name: Project Driver:	11F3 Eliminate East Network Ph 1&2 REL

Project Title:	Eliminate East End Network - Adelaide St. Area		
Project Manager:	Jagoda Borovickic	**Project Tech.:**	Jamie Macpherson
Supporting Reference Material			

Description/Justification

Phase 1:
In 2009, the London Police Department installed a customer-owned substation supplied off of the 27.6 kV distribution grid. This eliminated the need for the three transformer network vault that used to supply them along with the west portion of the east end network. These three network transformers were removed from service with the plan to replace them with a new 750 kVA padmounted transformer which will be placed on the Police Station's property. This budget item includes the installation of a new transformer that will provide long term supply to the former low voltage network grid in the area of Adelaide Street and Dundas Street. The result will be a smaller low voltage network in this area.

Phase 2:
A new development is proposed at 637 Dundas Street for 2011. Our plan is to provide this service from the 27.6 kV system by installing a padmount transformer. In conjuction with this project we are planning on installing another padmount transformer on an easement that will be provided by the developer. This transformer will provide supply to the low voltage network grid easterly of the boundary of Phase 1 project. This is consistent with our plan of eliminating the east end network.

The long term plan is to continue this philosophy by replacing the network transformers with polemounted and padmounted transformers that will be supplied from the 27.6 kV system.

COST ESTIMATE

Section - 150	**$465,000**

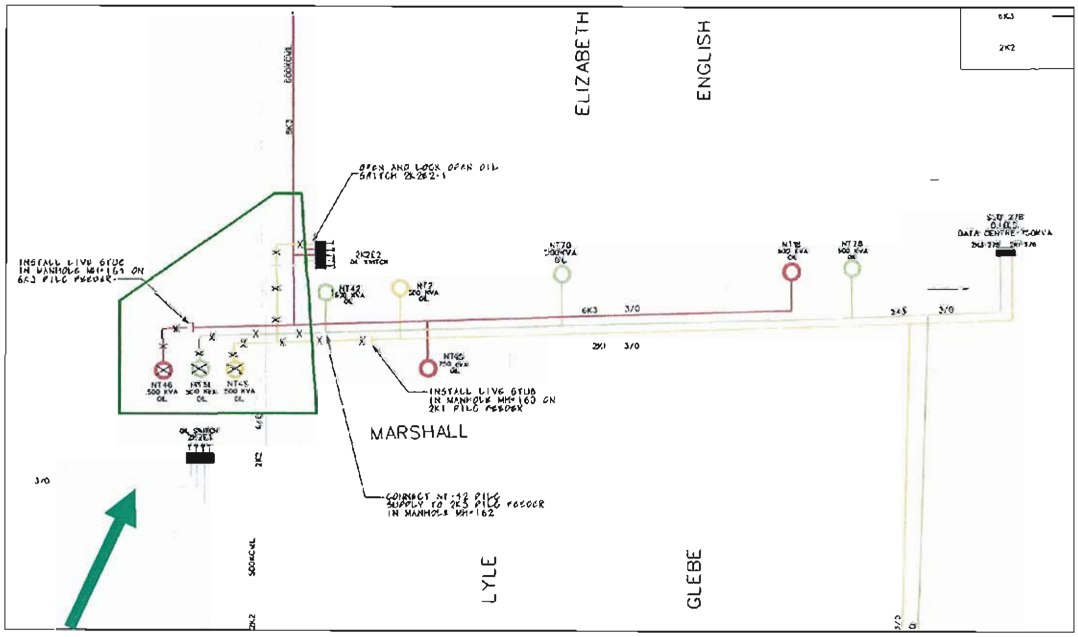
Prepared By: Allan Van Damme, P.Eng.
Manager of Engineering

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Eliminate East End Network – Adelaide St. Area
Project 11F3

This is the first phase of a multi-phase program to eliminate the east end network. The elimination of this network will provide a simpler and safer distribution system. The existing plant is approaching the end of its useful life. The plan will integrate with the significant redevelopment that is occurring in the area bordered by Adelaide and Rectory Streets along Dundas Street. All load will be converted from the 13.8 kV distribution system to the 27.6 kV distribution system in line with our long term plans for Nelson TS. The first phase will address the area of Adelaide and Dundas Street as shown below.

Area Affected by Phase 1 of the East End Network Elimination



Area Affected by Phase 1 of the East End Network Elimination

London Hydro **2011 ASSET MANAGEMENT PLAN** E&O Department		**Project Number:** **Project Name:** **Project Driver:**	11F4 Network PILC Replacement REL
Project Title:	Network Paper Insulated Lead Covered (PILC) Cable Replacement		
Project Manager:	Cole Tavener	**Project Tech.:**	Rolf Reiners
Supporting Reference Material	PILC Replacement Strategy at London Hydro, September 2010		
Description/Justification	PILC cable will be replaced with EPR cable where the PILC cable has been deemed to have reached end-of-life. Network transformer terminal chambers will be modified to accept EPR cable terminations and transition splices will be installed to provide an interface between the PILC and EPR cables. This capital plan will be executed in coordination with network transformer replacements.		

COST ESTIMATE

Section - 150	**$200,000**

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Network Paper Insulated Lead Covered (PILC) Cable Replacement
Project 11F4

London Hydro employs approximately 100km of PILC cable in the electrical systems emanating from Hydro One's Nelson transformer station. The age of the majority of PILC cable ranges from 60 to 80 years and it is expected that a significant portion of the asset population will soon reach end-of-life. For numerous reasons, explained in the document PILC Replacement Strategy at London Hydro, London Hydro has decided to transition from PILC cable to ethylene propylene rubber (EPR) insulated cable. Due to the differing configurations of PILC and EPR cable, this transition will require modifications to all network transformer (NT) terminal chambers and the installation of transitional splices. This project will provide long-term benefits to reliability, cost and the environment.

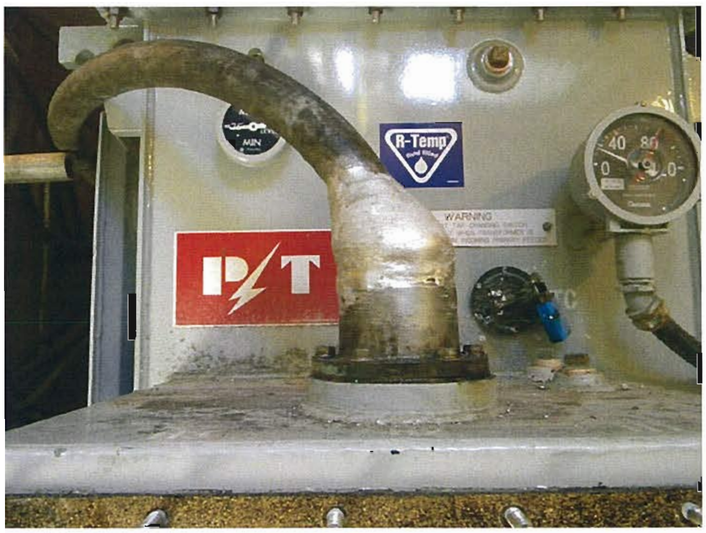


Figure 1: PILC Cable NT Connection.

Figure 2: EPR Cable NT Connection.

2011 ASSET MANAGEMENT PLAN **E&O Department**		**Project Number:**	11F5
		Project Name:	Network 208 Voltage Risers
		Project Driver:	SAF
Project Title:	Network 208 Voltage Risers		
Project Manager:	Jagoda Borovickic	**Project Tech.:**	Scott Lasseter
Supporting Reference Material			

Description/Justification

The City of London's downtown core area's customers are mostly supplied by the low voltage network grid. Generally these services are connected by the underground secondary cables installed in ducts. However, there are some services that are connected by the overhead secondary cables, supplied through the network risers. Since the high fault energies are a prevalent characteristics of this type of the low voltage network grid, these network risers and the overhead secondary conductors present potential arc flash hazards for the linemen working on them.

In order to eliminate the arc flash hazard and the probability of a catastrophic failure, London Hydro will be installing the current limiting fuses on the network risers. This budget item is allocated for fusing seven identified network risers.

COST ESTIMATE

Section - 150	**$70,000**

Prepared By: Jagoda Borovickic, P.Eng.
Distribution Engineer

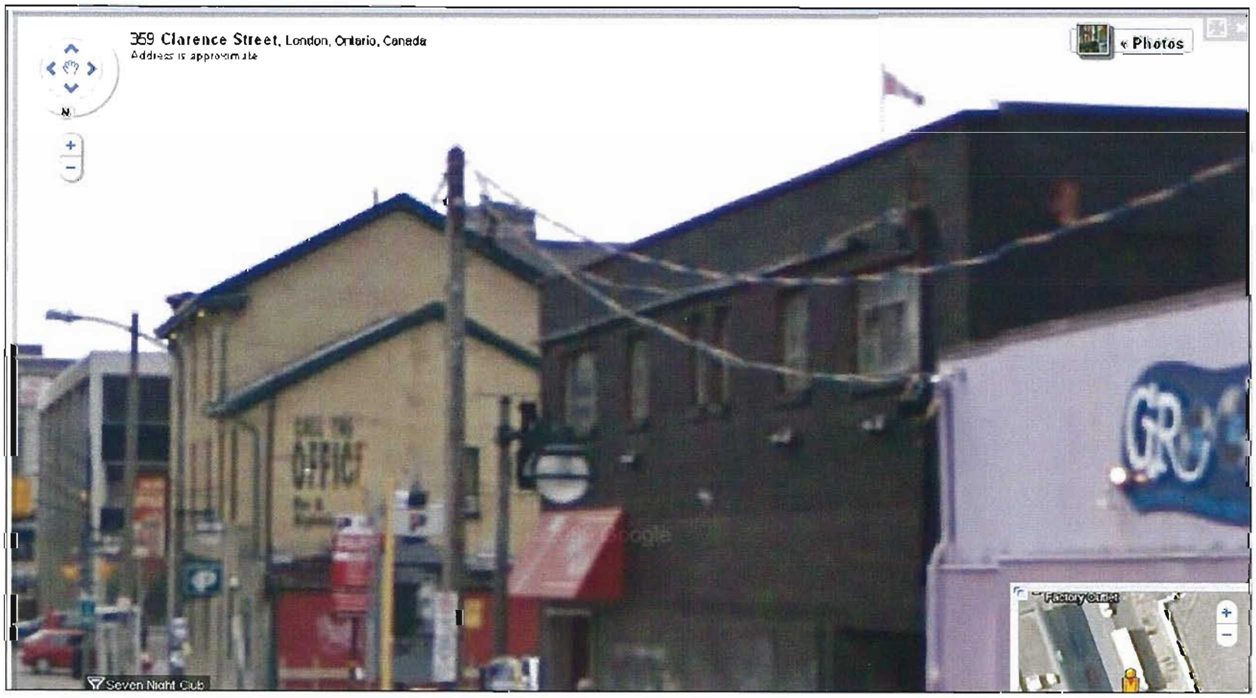
Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Network 208 Voltage Risers
Project 11F5

The City of London's downtown core is mostly supplied by the low voltage network grid. The prevalent characteristics of this type of the low voltage network grid are the high fault energies, and consequently, high arc flash. Generally, the services fed of the network grid are connected by the underground secondary cables installed in ducts. However, there are some overhead secondary services that are supplied through the network risers. These network risers and the overhead secondary conductors present potential arc flash hazard for the linemen while working on them. Linemen are not exposed to the high arc flash on the overhead services supplied by the overhead distribution transformers.

This safety issue will be eliminated by installing the current limiting fuses. Where feasible, the disconnect switch will be installed along with the current limiting fuse.

Typical Overhead Secondary Cable Network Riser



London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:** **Project Name:** **Project Driver:**	11F6 Manhole Cable Rebuilds SAF

Project Title: Manhole Cable Rebuilds

Project Manager: Jagoda Borovickic

Project Tech.: Dane Kirilovic

Supporting Reference Material

Description/Justification

The City of London's downtown core is largely supplied from the network system by an extensive low voltage network grid. The network is supplied by 13.8 kV PILC (paper insulated lead cable). The primary cables and the low voltage network grid cables are installed in the common duct and manhole system that became very crowded over the past fifty years. This item includes replacement of lead primary and secondary cables and reconfiguration of cables within crowded manholes that are difficult to work in.

In addition, this budget will cover installation of cable protecting fuses in the mains of the low voltage grid. High fault energies, that can lead to catastrophic failures, are predominant characteristic of the low voltage network grid These fuse elements limit the fault energy during the failure of the downstream device and decrease probability of catastrophic failures.

COST ESTIMATE

Section - 150	**$150,000**

Prepared By: Jagoda Borovickic, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Refurbishment of Low Voltage Network Grid
Project 11F6

The City of London's downtown core is largely supplied from the network system. The network is supplied by 13.8 kV PILC (paper insulated lead cable). Some of these cables are very old cables installed more than fifty years ago. The primary cables and the low voltage network grid cables are installed in the common duct and manhole system that became very crowded over the past fifty years. This item includes replacement of lead primary and secondary cables, and removal and reconfiguration of cables within crowded manholes that are difficult to work in. By doing this work we will eliminate unused cables, clear up hazards and make space available for future cable installations. The picture below is a good illustration of a crowded manhole in London's downtown core.

Manhole 347 - Intersection of Richmond St. & King St.

The City of London's downtown low voltage network grid consists of approximately 22 km of copper secondary mains that are routed through the downtown duct and manhole system. London Hydro has installed approximately 3000 cable protecting fuses on this system over the last five years to address the safety issues that are inherent a system of this design.

Low Voltage Cable Protecting Fuse used on Secondary Network

2011 ASSET MANAGEMENT PLAN
E&O Department

London Hydro

Project Number:	11G1
Project Name:	Replacement of Rotten Poles
Project Driver:	SAF

Project Title:	Replacement of Fully Depreciated Poles		
Project Manager:	Rod Doyle	**Project Tech.:**	Jim Soetemans
Supporting Reference Material	Pole Test Records Replacement of Fully Depreciated Overhead Distribution Areas Report, 2010		

Description/Justification

In the last several years, London Hydro tested almost 15,700 wood poles as part of our proactive maintenance approach. We have completed testing of all poles identified as being in poor and fair condition and poles identified in service for over 25 years or longer. Also, approximately 8,400 poles were retested in 2006, 2009 and 2010 as recommended in the previous year's test results. The testing involves performing a visual check of the pole and its equipment, sounding the pole, obtaining a core sample from the base of the pole when required and recording all relevant information.

This budget item will replace the approximately 36 poles that were identified in the 2010 pole testing program as being fully depreciated and requiring immediate replacement.

COST ESTIMATE

Section - 132	**$300,000**

Prepared By: Rod Doyle, P.Eng.
Distribution Engineer

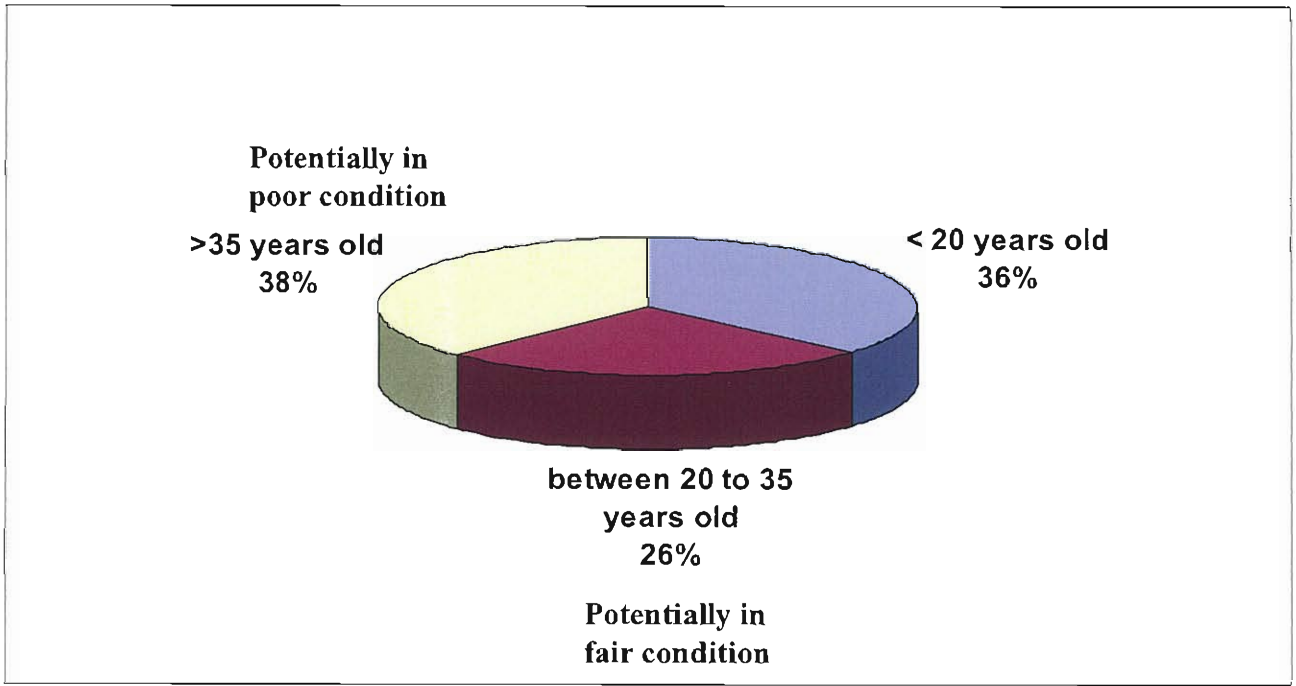
Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Replacement of Fully Depreciated Poles
Project 11G1

This project involves replacement of the fully depreciated wooden poles that were tested and recommended for replacement.

London Hydro's system contains almost 29,000 poles. Approximately 95% of the poles on London Hydro's system are made of wood. In 1998 London Hydro introduced the pole testing program that was based on the results of the infrastructure audit conducted on London Hydro's overhead system in the same year. Since then, London Hydro tested all poles identified as being in poor or fair condition during the infrastructure audit, poles that supposedly migrated from good to fair condition since the audit, and all poles that were recommended to be revisited in the previous testings. Also, poles that are older than 25 years are tested every 5 years. Pole testing is done on annually basis and capital expenditures are based on the results of the inspections.

A graph showing the overall pole age on London Hydro's system is shown below. Poles greater than 35 years in service have the potential to be in poor condition.



Potential Condition of Poles (28,889 Poles in Total) based on age.
The pole age is based on the current GIS data. Some pole ages have been estimated.

2011 ASSET MANAGEMENT PLAN E&O Department	
Project Number:	11G2
Project Name:	Replacement of Pole Fire Poles
Project Driver:	REL

Project Title:	Replacement of Poles Susceptible to Pole Fires
Project Manager:	Rod Doyle
Project Tech.:	Jim Soetemans
Supporting Reference Material	Mitigating Pole Fires on London Hydro's Distribution System Report Acres Infrastructure Report Replacement of Fully Depreciated Overhead Distribution Areas Report, 2010

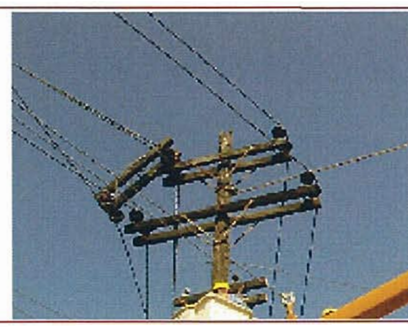
Description/Justification

The areas designated for replacement consists of the plant built more that 40 years ago and is identified in the above reports as requiring replacement. This plant consists of outdated and aged materials and construction techniques that are more prone to failure than those used today. This budget item includes the pole lines in the following areas:

1. First St. (Oxford to Spanner). This pole line is a radial supplying residential and commercial load and will coordinate with a depreciated area replacement under Project Number 11G3.
2. Highbury Ave. (Power to Hamilton). This pole line is the trunk of the 19M27 feeder; therefore, a risk for a high impact outage.
3. Capulet Ln. (north of Oxford). This pole line is the trunk of the 26M42 feeder; therefore, a risk for a high impact outage.
4. Leathorne St. (Commissioners to Adelaide). This pole line is the trunk of the 4M14 feeder; therefore, a risk for a high impact outage. Only reframing the poles is required.
5. Hargrieve Rd. (Newbold to Bessemer). This pole line is a radial supplying commercial load; therefore, a risk for a long outage.

COST ESTIMATE

Section - 132	**$500,000**



Prepared By:	Rod Doyle, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

Replacement of Poles Susceptible to Pole Fires

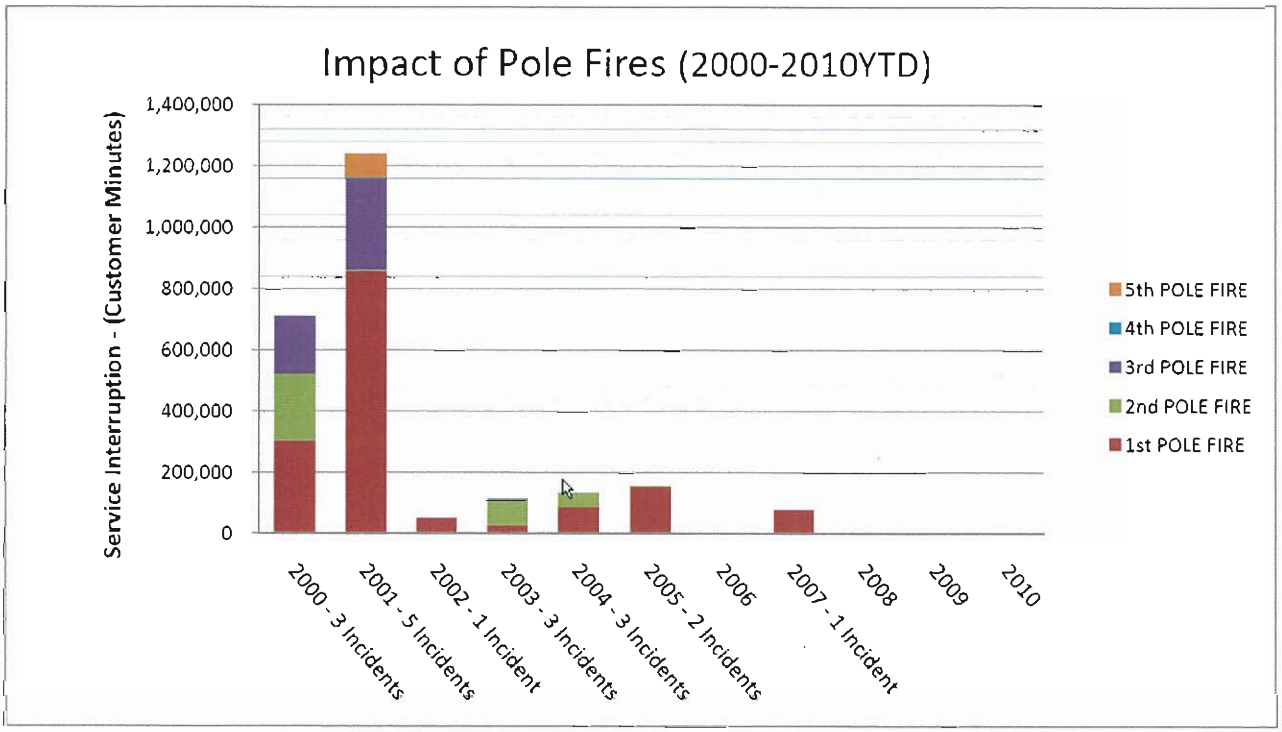
Project 11G2

The five projects scheduled for 2011 involve replacement of 38 poles susceptible to pole fires and reframing an additional 7 poles susceptible to pole fires.

Pole fires occur in specific older types of overhead construction with wood crossarms and pin type insulators. In these types of construction, leakage current tracks over deteriorated insulators and becomes concentrated in places where bolts and steel brackets interface with the wood resulting in fires.

Several years ago London Hydro instituted the pole fire replacement program and to-date has completed 68% of the projects, representing approximately 72% of the suspect poles. This resulted in the significant improvement in the system performance as illustrated on the graph below. The replacement program will continue on an annual basis until the time that all pole fire prone poles are replaced.

After completing the five pole-fire projects scheduled for 2011, 78% of the pole-fire projects (approximately 79% of the suspect poles) will be completed.



Impact of Pole Fires on System Reliability

2011 ASSET MANAGEMENT PLAN

London Hydro

E&O Department

Project Number:	11G3
Project Name:	Rebuild Depreciated Areas
Project Driver:	REL
Project Title:	Rebuild of Fully Depreciated Overhead Areas
Project Manager:	Rod Doyle
Project Tech.:	Hank Bonnar & Jim Soetemans
Supporting Reference Material	Acres Infrastructure Report Replacement of Fully Depreciated Overhead Distribution Areas Report, 2010

Description/Justification

The Acres Infrastructure Assessment identified various parts of the system in this area as being in poor condition. The deficiencies related to the age of the equipment may adversely impact the reliability of supply as well as public and employee safety. The poles and associated hardware are approximately 50 years old. Many of the transformers in the area are operating in excess of their capacity due to load which has been added by customers over the years (i.e. air-conditioning and other appliances).

In 2010 a city wide audit focusing on depreciated areas was completed and yielded the following areas as priority: Note - some areas will be rebuilt over a number of years / phases.

1. Old East - Phase 1 of 3. This area bounded by Elias St., Dundas St., Ontario St. and Burbrook Pl. was deemed the worst depreciated area in terms of overall condition.

2. Pond Mills - Phase 1 of 2. This area on the southwest corner of Commissioners Rd.E. and Pond Mills was deemed the second worst depreciated area. Converting this area will also assist with offloading Sub 15, which experienced a failed transformer last year.

3. First St. area - Phase 1 of 2. This area bounded by Oxford St.E., Spanner St., First St. and Second St. was deemed fourth worst depreciated area. This work will co-ordinate with First St. pole fire project under project number 11G2.

4. Old South area. Some of the remaining worst conditioned streets in this area will be rebuilt.

COST ESTIMATE

Section - 132	**$2,497,000**

Prepared By:	Rod Doyle, P.Eng. Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

Replacement of Fully Depreciated Areas
Project 11G3

London Hydro has established a set of criteria to be used when prioritizing which fully depreciated overhead areas are to be rebuilt. These include: results from the visual audit conducted on the overhead system in 1998, OEB infrastructure audit results, pole testing results, safety issues, system performance, accessibility and reliability.

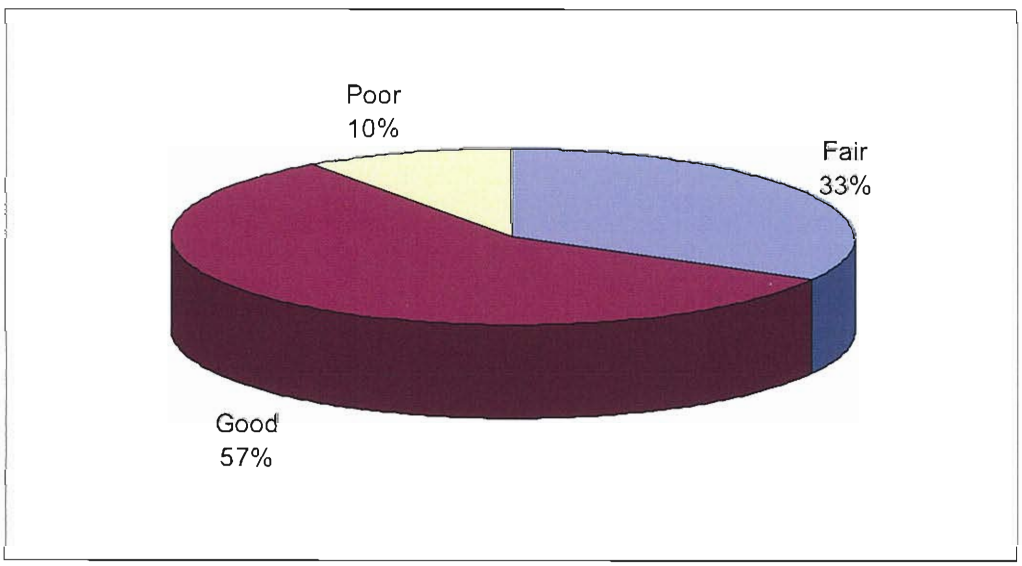
London Hydro completed an audit of its most depreciated overhead areas. Twenty-seven areas were evaluated based on a number of factors, such as:

- overall condition, which included pole, wood crossarms, transformers and conductors
- safety conditions, which included adequate anchoring, #6 Copper, grounds, non-standard framing, encroachments
- environment, which included leaking transformers
- accessibility and operability

Some areas are in extremely poor condition and require complete rebuilds. Most of the poorest conditioned areas are at the vintage 4.16kV distribution system. Conversion of this voltage system will be implemented to benefit other system requirements such as offloading substations and improve system efficiency (reduce system losses).

London Hydro has over 1323 km of overhead distribution circuitry within the City of London boundaries. The condition of the circuitry has been ranked good, fair or poor. Last year, 132 km of this circuitry was identified in poor condition. The depreciated plant is rebuilt on an annual basis by prioritizing area based on the plant condition. This year's budget will allow rebuilding of approximately 10 km of the fully depreciated overhead plant under this item.

The graph showing condition of the existing London Hydro's overhead plant has been created and is shown below.



Condition of London Hydro's existing Overhead Distribution System based on length (2009)

2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11G4
	Project Name:	13M15 Overhead Enhancements
	Project Driver:	REL

Project Title: 13M15 Overhead Reliability Enhancements

Project Manager:	Rod Doyle	Project Tech.:	Hank Bonnar

Supporting Reference Material

Kinectrics Report No. K-014857-001-RA-0001-R00
Lightning Protection Study for London Hydro - October 2009

2009 Quality of Supply Report

Description/Justification

The 2009 Quality of Supply Report identified the 13M15 feeder as having the worst performance of all feeders in London Hydro's system; furthermore, the 13M15 feeder has been listed in the worst 10 performing feeders four of the last 5 years.

This budget section will implement some of the recommendations from the 2009 Quality of Supply Report to assist in proving the reliability of the 13M15 feeder. The recommendations include:

- animal protection such as insulated switch/cutout brackets and transfomer coverup
- change porcelain insulators
- supsension arresters
- recloser (the 13.8kV high fault levels might prevent the implementation of a recloser)

COST ESTIMATE

Section - 132	$160,000

Prepared By: Rod Doyle, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

13M15 Overhead Reliability Enhancements

Project 11G4

A recent audit of the 13M15 feeder indicated inadequate animal protection on this feeder. This budget section will allow installation of animal guards on the transformers and replace un-insulated transformer and riser brackets with insulated brackets. A large scale lightning mitigation involving arresters on every pole will not be implemented at this time until London Hydro can properly evaluate the effectiveness of a similar project on the 26M53 feeder. Also, arresters on every pole is not desirable for the 13M15 feeder at this time since this feeder may be rebuilt in the next few years as part of the future Nelson TS expansion. Instead, only a few strategic locations will be chosen for arrester installation. An alternative to a large mass implementation of arresters, and to compensate for the lack of reclosing capability at the station breaker, will be the installation of a recloser on this feeder.

Supply Station:	**Nelson**	**Feeder Circuit Designation:**	**13M15**
Location: Nelson St. and William St.			
Number of Customers on Feeder:	**816**	Position in 2008: Average position in the last 5 yrs:	**8** **17**
Customers Affected:	**7,630**	Unplanned Customer-Minutes of Interruption:	**178,462**
FAIFI:	**9.35**	FAIDI:	**3.65**

Assessment and Planned Action:

This feeder was ranked the most unreliable on the system in 2009. It has also been in the top ten worst feeders repeatedly in 2004, 2005 and again 2008. Previous reports have identified issues related to the state of the infrastructure (audit proposed in 2005) or the need to improve the lightning protection (in 2008). The poor performance of 13M15 in 2009 is attributed mainly to ***Foreign Interference:*** one particular customer substation caused five outages all resulting in breaker operations. These were responsible for more than half of the customer interruptions in this category. The privately owned switchgear was found defective and so the customer substation was disconnected after multiple outages occurred. Three additional breaker operations were attributed to the ***Lightning, Loss of Supply and Unknown*** categories. Lightning was also one of the noticeable contributors to poor indices on this feeder in the analysis of the previous year; mitigation methods will be implemented now that the lightning study is completed.

It has been recognized for a while that breaker reclosing functionality on 13M15 could be beneficial. Many of the above cause categories would have possibly created only an auto-reclosure given the nature of the temporary faults (such as lightning or unknown). It is recommended to contemplate upgrading the protection of the breaker to incorporate/activate reclosing functionality. Although none of the 13.8 kV feeder breakers reclose on a fault, in the case of a circuit with mainly overhead construction, reclosing could limit the number of breaker operations, hence contributing to better FAIFI and FAIDI for this feeder. If the transmitter's costs for protection enhancement at the station are not justified, then in-line reclosers at various locations may also be considered once further analysis is carried out.

Also, an audit was performed on this feeder in 2009; the results indicate opportunities for improvement which should be implemented.

The above figure is taken from the 2009 Quality of Supply Report, Appendix 2.

London Hydro **2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:** 11G5 **Project Name:** 26M53 Overhead Enhancements **Project Driver:** REL

Project Title:	26M53 Overhead Reliability Enhancements		
Project Manager:	Rod Doyle	**Project Tech.:**	Hank Bonnar

Supporting Reference Material

Kinectrics Report No. K-014857-001-RA-0001-R00
Lightning Protection Study for London Hydro - October 2009

2008 Quality of Supply Report

Description/Justification

In 2010, London Hydro undertook to implement methods to mitigate the momentary outages experiencing on a critical feeder; the 26M53. This feeder is critical because it supplies a large generator and is the backup supply to the downtown network ring-bus. London Hydro implemented one of the recommendations from the *Lightning Protection Study* by installing arresters on every pole's top phase.

This project will continue with implementing the remaining momentary outage mitigation techniques by installing animal guards on the transformers and replacing un-insulated transformer and riser brackets with insulated brackets.

COST ESTIMATE

Section - 132	**$110,000**

Prepared By: Rod Doyle, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

26M53 Overhead Reliability Enhancements
Project 11G5

A critical customer that is also a large generator that can supply backup to the downtown network ring-bus, complained about the high frequency of momentary outages on their supply feeder; the 26M53. Outage records indicated that the 26M53 feeder did have poor performance in the MAIFI category – experiencing more momentary outages than most feeders. The majority of these momentary outages are attributed to lightning and animal contacts. London Hydro undertook to implement the lightning mitigation techniques, involving arresters on every pole's top phase as recommended by Kinectrics' *Lightning Protection Study for London Hydro - October 2009* report.

A recent audit of the 26M53 feeder indicated inadequate animal protection on this feeder. This budget section will allow installation of animal guards on the transformers and replace un-insulated transformer and riser brackets with insulated brackets. This project should reduce the momentary outages experienced by the 26M53 feeder attributed to animal contacts and strengthen the backup supply to the downtown network ring-bus.

London Hydro	**2011 ASSET MANAGEMENT PLAN** **E&O Department**	**Project Number:**	11G6
		Project Name:	Removals and Restoration
		Project Driver:	REL
Project Title:	Removal and Restoration of Overhead Plant		
Project Manager:	Rod Doyle	**Project Tech.:**	Hank Bonnar & Jim Soetemans
Supporting Reference Material			
Description/Justification	In 2011, London Hydro will be completing overhead pole line rebuilds in various areas within the city. These rebuilds involve many pole hole excavations and pole removals. This budget will be used to complete restoration in these areas. It is noted that these removals must be coordinated with our joint use partners such as Bell & Rogers and thus timing is dependent of external parties.		

COST ESTIMATE

Section - 132	**$30,000**

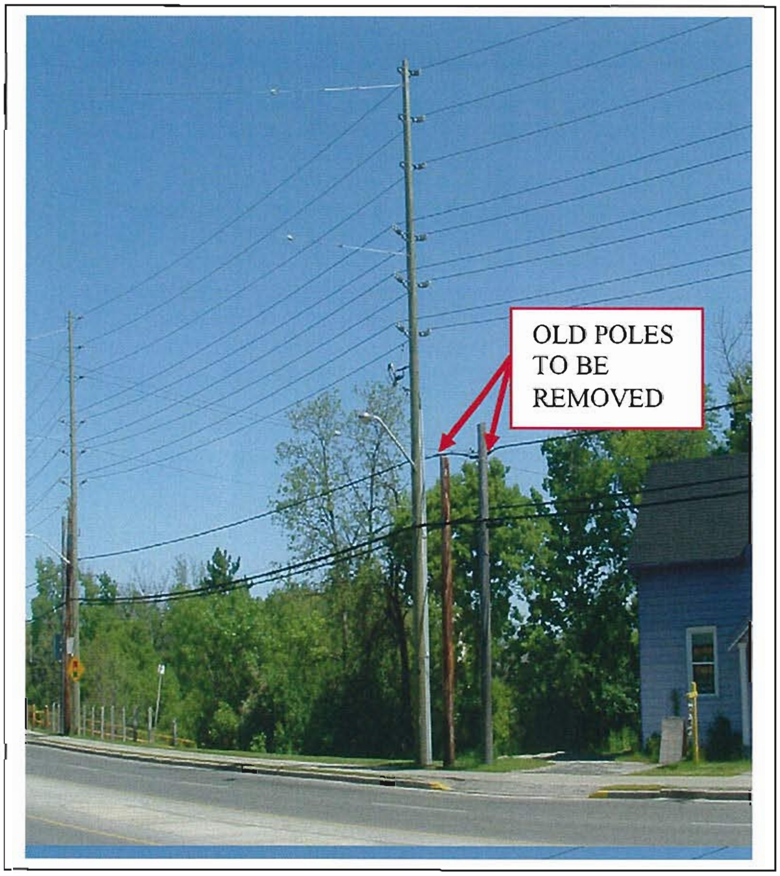
Prepared By: Rod Doyle, P.Eng.
Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Removals and Restoration

Project 11G6

The picture below is an example of new hydro pole construction, where the old structure is still supporting 3rd party attachments. The final phase of construction involves the removal of this structure, but must be co-ordinated with the 3rd party utilities (i.e. Rogers Cable, Bell) still attached to our poles.



2011 ASSET MANAGEMENT PLAN **E&O Department**	**Project Number:**	11H1
	Project Name:	Reclosers Installations
	Project Driver:	REL

Project Title:	Automation on Feeders - Recloser Installations		
Project Manager:	Rod Doyle	**Project Tech.:**	Jim Soetemans
Supporting Reference Material	Quality of Supply Report 2008		

Description/Justification

This project has been budgeted to install 6 reclosers to facilitate SCADA switching, fault isolation and restoration. Installation of these devices has resulted in significant improvements in reliability. The reclosers will be installed at the following locations;

1) SW 01252, Fanshawe Road east of North Centre Road
2) SW 02430, Gainsborough Road east of Wonderland Road
3) P45-6, Wavell Street east of Substation 92
4) P54-1, Commissioners Road west of Wonderland Road
5) SW 5029, Bathurst Street*
6) SW 5041, Simcoe Street*

*This project is contingent on the standards department's approval of a recloser rated for service on the 13.8kV system (i.e. fault interrupting, fault 3s, etc.). If an appropriate recloser is not approved, the project listed below will proceed.

5) N52-1, Southdale at White Oaks Road
6) N52-7, Southdale at White Oaks Road

COST ESTIMATE

Section - 250	**$320,000**

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Recloser Installations

Project 11H1

The installation of automated switches or reclosers on major feeders has a positive impact on the duration and frequency of outages. London Hydro now has over 100 automated devices in the field and plans to continue installing reclosers until there is an average of 2.5 reclosers per 27.6 kV feeder.

The installation of reclosers is a very cost effective way of improving SAIFI reliability (System Average Interruption Frequency Index). A report was developed into an industry paper entitled "Use of Reclosers on London Hydro's Electrical System" (included in abstract) that examined various methods for evaluating the cost effectiveness of reliability improvement programs.

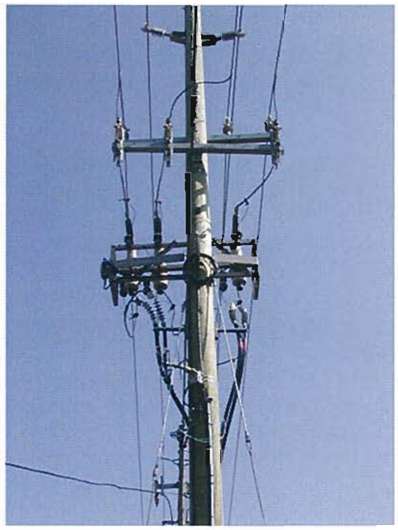


Figure 1 – Horizontal Recloser Installation

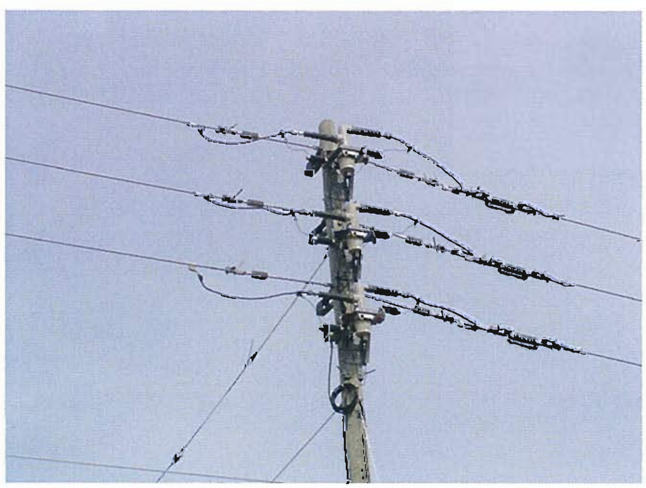


Figure 2 – Vertical Recloser Installation

2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11H2
	Project Name:	Network Temperature Monitoring
	Project Driver:	REL

Project Title:	Installation of Network Temperature Monitoring Devices
Project Manager:	Ed Jambor
Project Tech.:	Kim Franklin
Supporting Reference Material	

Description/Justification

When network transformers or cables are taken out of service, network loads will shift in ways that are difficult to predict. Although we do our best to model the system and to provide reinforcements where required, parts of the system can still get overloaded during contingency conditions. Exactly how many cable half sections can be out of service without causing overheating of the remaining parts of the network is an ongoing question.

We experimented with a low cost temperature monitor in 2009 that has done a good job of keeping track of cable and mole surface temperatures. If enough of these are installed in key locations it will give us better information on how network loads shift during planned and emergency outages. This will allow us to provide reinforcements to help prevent future cable failures and network fires.

The money provided will allow for dozens of temperature monitors to be installed in key locations.

COST ESTIMATE

Section - 250	**$10,000**

Prepared By:	Ed Jambor, P. Eng. Director of Operations
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11H3
	Project Name:	RTU Replacement Program
	Project Driver:	REL

Project Title:	Remote Terminal Unit (RTU) Replacement Program
Project Manager:	Cole Tavener
Project Tech.:	Rolf Reiners
Supporting Reference Material	Asset Management Plan 2010 to 2024
Description/Justification	The purpose of this project is to develop a standard remote terminal unit (RTU) design employing micro-processor based equipment. The standard will include a description of the design decisions, detailed wiring prints and a bill of materials. A single substation RTU will be replaced to test the standard. The design will be leveraged to provide the foundation for a RTU replacement program to address the replacement of up to 20 RTUs between 2012 and 2017.

COST ESTIMATE

Section - 250	**$50,000**

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Remote Terminal Unit (RTU) Replacement Program
Project 11H3

RTUs provide the interface between substation devices and the SCADA master computer. In addition to remote control, these devices enable remote observation of the system's configuration and load flows. The ability to observe the system remotely is critical to system reliability, specifically System Average Interruption Duration Index (SAIDI).

London Hydro currently utilizes 45 RTUs to monitor its substations. Over half the asset population is no longer supported by the manufacturer and the oldest units have exceeded their expected useful life by nearly a decade. One third of the asset population consists of piloted equipment that was found to be inadequate. To maintain system observation and control capabilities, a RTU replacement program must be initiated.

Manufacturer	Type	Quantity	Earliest Installation
Cat Com Systems	Rantech	26	1983
GE Multilin	DART	5	1995
SEL	2032	4	2007
Natis Communications	RTU3200	3	2008
G&W	ATC	3	2000
GE Multilin	Ibox	2	2003
GE Multilin	D20	2	2002

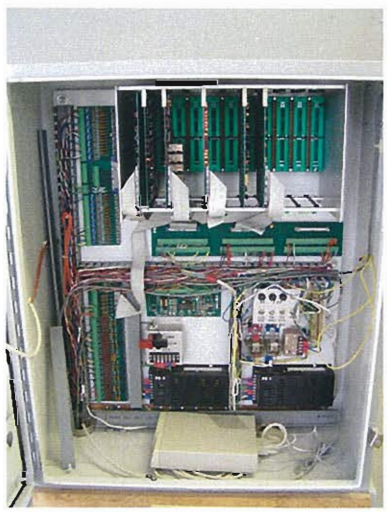


Figure 1 – Rantech Circuit-Board RTU

Figure 2 – SEL 2032 Micro-Processor RTU

2011 ASSET MANAGEMENT PLAN E&O Department	Project Number:	11H4
	Project Name:	SCADA Communications
	Project Driver:	REL

Project Title:	SCADA Communications Enhancements

Project Manager:	Cole Tavener	**Project Tech.:**	Rolf Reiners

Supporting Reference Material

1. Operations Department, IBM Review of the RF Systems, October 2006,
2. Asset Management Plan 2010 to 2024

Description/Justification

This is the preliminary engineering phase of a SCADA communications project that will begin implementation in 2012. The project is driven by the need to replace existing infrastructure that has exceed its useful life and to address an increased data load. The increased data load is the result of a growing population of intelligent electronic devices that communicate with the SCADA master using modern technologies and protocols.

COST ESTIMATE

Section - 250	**$20,000**

Prepared By:	Cole Tavener Assistant Distribution Engineer
Approved By:	Ken Walsh, P.Eng. Chief Engineer & V.P. of Operations

SCADA Communications Enhancements
Project 11H4

In 2010, the Asset Management plan (2010 to 2014) identified a need to replace the SCADA master communications hardware in 2012 at a cost of $400,000. This work is required because the equipment has exceeded its expected useful life, it is technically obsolete, and there has been no manufacturer support for some time. Changes to communications technology since 1993, when the existing hardware was designed, have been so significant that the new hardware is unlikely to bare any resemblance to the existing equipment. New electronic relays employ SCADA communications interfaces allowing direct communication with the SCADA master. In addition, long-standing communications technologies may soon be discontinued. (Although London Hydro has not received notification, Bell has informed Union Gas that leased line support will cease in 2012.) A recent review of London Hydro's radio communications systems made recommendations regarding the SCADA radios, however no engineering was undertaken to address the SCADA communications system in its entirety. Before new communications hardware can be installed, preliminary engineering must be completed to determine the optimum use of available technologies and to provide a long-term SCADA communications solution.

Figure 1 – Existing Globalview Serial Modem

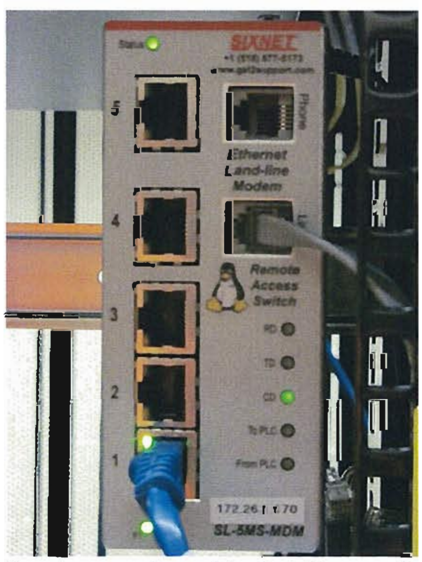


Figure 2 – Innovation Park Ethernet Modem

London Hydro

2011 ASSET MANAGEMENT PLAN
E&O Department

Project Number:	11H5
Project Name:	Migration to Digital Radios
Project Driver:	REL

Project Title:	Migration to Digital Radios		
Project Manager:	Cole Tavener	**Project Tech.:**	Rolf Reiners
Supporting Reference Material	Operations Department, IBM Review of the RF Systems, October 2006		

Description/Justification

When this project is complete, all mobile voice communications radios used by London Hydro will be capable of communicating using digital radio signals.

COST ESTIMATE

Section - 140	**$65,000**

Prepared By: Cole Tavener
Assistant Distribution Engineer

Approved By: Ken Walsh, P.Eng.
Chief Engineer &
V.P. of Operations

Migration to Digital Radios
Project 11H5

By reducing channel bandwidth from 25kHz to 6.25kHz, the adoption of digital radio communications will effectively quadruple the number of available radio communications channels. A review of London Hydro's radio system, conducted in 2006 by IBM, found Industry Canada has already begun a migration to digital communications in the frequency bands surrounding London Hydro's voice frequencies. A local radio equipment supplier believes manufacturers will cease production of analogue radio equipment by 2012.

In 2008 digital-capable radio communications equipment was installed at the 111 Horton Street tower and the Reservoir Hill tower. Since 2008, 28 digital-capable mobile radios have been installed in London Hydro vehicles and security has begun using digital-capable handheld radios. To complete the transition to digital radio voice communications London Hydro must purchase 65 mobile radios. Once all radios are capable of digital communications, the radio system can be converted to digital communications by simply changing equipment settings. This conversion will improve the quality of radio voice communications and reduce the resources required to maintain the voice communications system.

Figure 1 – Midland Analogue Radio

Figure 2 – Motorola Analogue/Digital Radio

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APPENDIX 2F – SERVICE QUALITY & RELIABILITY PERFORMANCE INDICATORS

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LONDON HYDRO INC.
OEB SERVICE QUALITY AND RELIABILITY PERFORMANCE INDICATORS

Service Quality Indicator	Minimum Standard	2009	2010	2011	Average
Connection of New Services - Low Voltage	90% of requests met within 5 working days	99.9	98.6	97.6	98.7
Connection of New Services - High Voltage	90% of requests met within 10 working days	100.0	No Requests	100.0	100.0
Appointment Scheduling	90% scheduled within 5 working days	97.9	95.5	93.4	95.6
Appointments Met (customers must be offered their choice of morning or afternoon appointments)	90% of appointments must be met at the appointment time	99.5	99.7	99.5	99.6
Rescheduling a Missed Appointment a) attempt to contact customer in advance b) attempt to contact within 1 business day to reschedule	100% of all missed appointments are rescheduled	100.0	100.0	100.0	100.0
Telephone Accessibility	65% of all incoming calls to the general inquiry number to be answered within 30 seconds	56.3	67.1	67.3	63.6
Telephone Call Abandon Rate	Less than 10%	17.1	3.0	2.1	7.4
Written Response to Inquiries	80% of customer requests for written information must be met within 10 working days	100.0	100.0	100.0	100.0
Emergency Response – Urban	80% of emergency trouble calls received from fire, ambulance or police responded to within 60 minutes	95.2	98.0	100.0	97.7
Reconnection Performance Standards (effective 2011)	85% of customers reconnected within 2 working days of making payment in full or entering arrears payment agreement	n/a	n/a	96.2	n/a

LONDON HYDRO INC.
OEB SERVICE QUALITY AND RELIABILITY PERFORMANCE INDICATORS

Reliability Performance Indicator	Minimum Standard	2009	2010	2011	Average
SAIDI (System Average Interruption Duration Index) <2.29 Code 2: Exclude loss of supply	Within the range of performance over the previous 3 years	0.89 0.82	0.88 0.85	1.86 1.67	1.21 1.11
SAIFI (System Average Interruption Frequency Index) <2.39 Code 2: Exclude loss of supply	Within the range of performance over the previous 3 years	1.59 1.38	1.12 1.00	2.36 2.14	1.69 1.51
CAIDI (Customer Average Interruption Duration Index) <0.96 Code 2: Exclude loss of supply	Within the range of performance over the previous 3 years	0.56 0.59	0.79 0.84	0.79 0.78	0.71 0.74
MAIFI (Momentary Average Interruption Frequency Index)		4.41	2.83	4.81	4.02

APPENDIX 2G – GREEN ENERGY ACT PLAN

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London Hydro's Green Energy Plan

Reviewed by:

M. Chase, CMA, MBA

Director Finance

Reviewed by:

W.A. Milroy, P. Eng

Director Network Planning

Prepared by:

G. A. Sheil, P. Eng

Manager of Standards

June 25, 2012
(revised July 27, 2012)

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Appendix

1. Introduction

1.1 The Green Energy Act – Background

The Green Energy and Green Economy Act, 2009 ("**GE&GEA 2009 Act"**) came into force on September 9, 2009. This Act essentially combined and amended the *Ontario Energy Board Act, 1998* and the *Electricity Act, 1998* to encourage renewable generation connections and smart grid investments.

On March 25, 2010 the Ontario Energy Board issued the report **EB-2009-0397 Filing Requirements: Distribution Plans – Filing under Deemed Conditions of Licence**, that mandates the time and manner in which LDC's are required to file distribution system plans pertaining to the connection of renewable generation facilities. The report builds on the **GE&GEA 2009 Act** and the related **Guidelines G-2009-0087: Deemed Condition of Licence: Distribution System Planning** that includes requirements for distributors to prepare plans related to connecting renewable generation and making smart grid investments.

Every distributor must file a Green Energy Act Plan ("GEA Plan") as part of the Cost of Service Rate Application for 2012 and subsequent rate years, The GEA plan must be tied to any cost recovery the distributor is seeking through a rate application. The report also provides direction related to the inclusion of Smart Grid development activities and expenditures in distribution system plans. When the report was issued the government had not made regulations or issued directives regarding the development of the Smart Grid.

Every Local Distribution Company ("LDC") is required to submit a GEA Plan to the Ontario Power Authority ("OPA") for comment no later than 30 days before filing a service rate application. Comments received from the OPA must be included in the GEA plan which forms part of the service rate application. Submission of a GEA plan provides LDC's an opportunity to receive funds to expand or reinforce their system for approved generation projects and/or prior to any formal applications for renewable generation. The report does not limit an LDC's obligation to connect generation projects.

The OPA requires every LDC to submit either a Basic Plan or a Detailed Plan; as a minimum each LDC must file a Basic Plan. The threshold/criteria for submitting a Detailed Plan is based on one of two *materiality limits*. The materiality limits are:

1) Projects planned in one year exceeding $5M **or that "**are more than $100,000 **and** exceed 3% of the rate base".

   In London Hydro's case three percent (3%) of our rate base equals $6.75M. Therefore, **$5M** in projects in one year is our threshold for producing a Detailed Plan.

2) Projects planned over 5 years that exceed $10M or that "are more than 6% of the rate base".

Six percent (6%) of London Hydro's rate base equals $13.5M. Therefore, **$10M** in projects planned over a **5 year** period is our threshold for producing a Detailed Plan.

In regards to renewable generation connections, London Hydro acknowledges that there are no specific renewable generation project expenditures in our approved capital plans. Therefore, London Hydro does not meet either of the materiality limits of the OPA and as a result London Hydro will be submitting a Basic Plan (see Section 4 Requirements of a Basic Plan).

1.2 Acronyms

The following acronyms are used in this report.

CIA	=	Connection Impact Assessment
DAT	=	Distribution Availability Test
DG	=	Distributed Generation
DGEO	=	Distributed Generation End Open
ECT	=	Economic Connection Test
FIT	=	Feed-In Tariff (version 1.0 and version 2.0)
GEA	=	Green Energy Act
IFA	=	Initial Feasibility Assessment
kV	=	kilovolts (1000 volts)
kVA	=	kilovolt-amperes (1000 volt amperes)
kW	=	kilowatts (1000 watts)
kWh	=	kilowatt-hour (1000 watt hours)
LDC	=	Local Distribution Company, in this case London Hydro
OEB	=	Ontario Energy Board
OPA	=	Ontario Power Authority
TAT	=	Transmission Availability Test
TS	=	Transformer Station
TT	=	Transfer Trip

1.3 Overview of London Hydro's Distribution System

London Hydro Incorporated is a wholly owned subsidiary company of the Corporation of the City of London. London Hydro services roughly 148,000 customers within the City of London's boundary which encompasses approximately 420 square kilometres. Electricity is supplied by six high voltage transformer stations that are owned and operated by Hydro One. The distribution circuits emanating from these stations operate at a variety of voltages, the most predominant being 27.6kV and 13.8kV. London Hydro owns and operates 38 substations that distribute power at 4kV, and 5 substations that distribute power at 13.8kV. In total, London Hydro has approximately 2,600 km of primary conductor. Within the core area, there is also a separate low voltage, (120/208V) network grid distribution system consisting of 94 network transformers; these are supplied at 13.8kV and are housed in 60 vaults under the sidewalks of downtown city streets. London Hydro is a summer peaking utility with a peak load of approximately 700 MW.

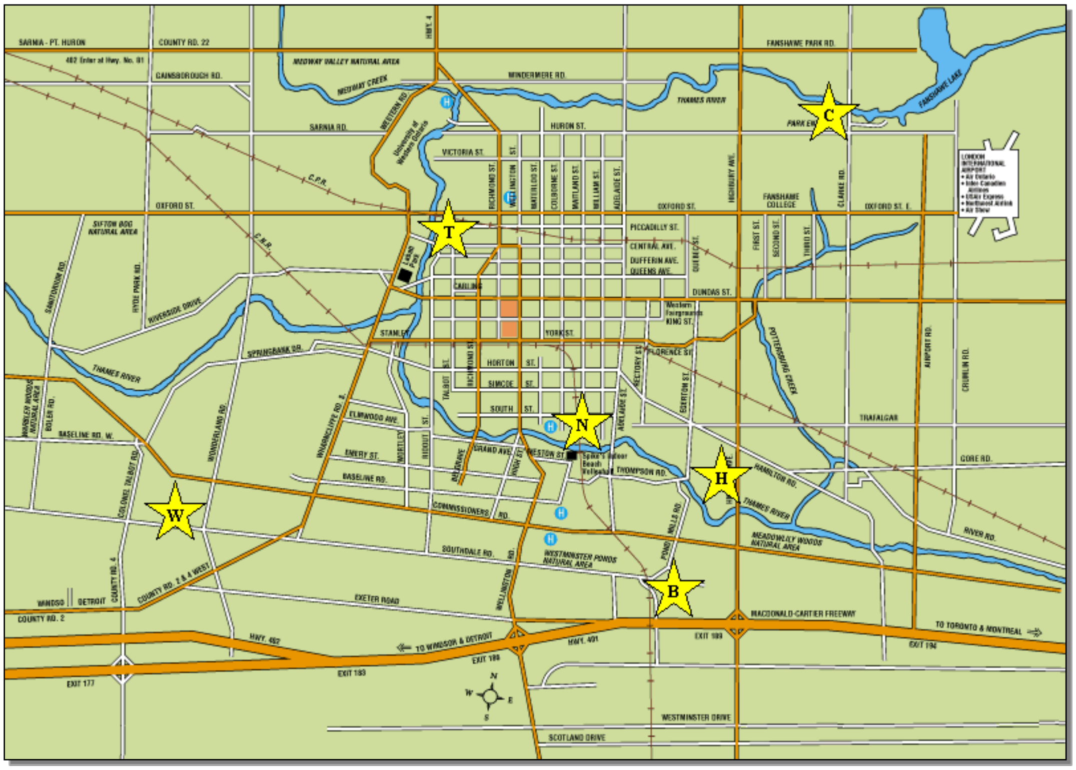

Figure 1: Locations of Transformer Stations

2. Distributed Generation

2.1 FIT 2.0

The FIT program has recently undergone the mandated 2-year review to ensure it is still relevant and reflects the current capital costs of installing generation facilities. As a result recommendations have been made that would balance the interests of all Ontarians, recognizing ratepayers, community participants and the renewable energy retail sector.

Several rule changes are expected to be released that may affect the program uptake.

- A significant reduction in solar price paid per kWh
- Contracts awarded based on available capacity – there is no ECT
- Small FIT (=<500kWh) now requiring a TAT / DAT
- Small FIT (=<500kWh) now requiring an application security
- Further tightening of the land use restrictions

2.2 Embedded Generators (Legacy, Net Metered, RESOP, microFIT and FIT)

The two tables below list the total kW of connected generation within London Hydro's service territory. The list includes generation projects resulting from government programs (Net Metered, RESOP, microFIT and FIT) as well as Legacy projects.

Micro-generation Projects	Applications Outstanding*	Applications Terminated	Connected (microFIT)	Connected (Net Billing)	Total Connected Micro-generation
Total	104	135	101	5	106
Total kW	891 kW	1183 kW	823 kW	15 kW	**838 kW**

Table 1: Distribution Generation Activity (<10kW)

* The number of outstanding applications includes projects that have received an offer to connect

Generation Size	IFAs Completed	CIAs Completed[1]	DG Connections	Total kW Connected	Generation Source
Small (>10kW & ≤1MW)	304	11	5[2]	604	PV Solar
	0	0	1[3]	675	Water
Mid-Sized (>1MW & ≤10MW)	0	1	1[4]	2,850	Bio-gas
	0	1	2[5]	12,000	Natural gas
	11	0	0	0	PV Solar
Large (>10MW)	0	0	2[6]	36,600	Natural gas
Total DG projects	**315**	**13**	**11**	**52,731 kW**	

Table 2: Distribution Generation Activity (>10kW)

[1] Current CIA's: Home Depot (3035 Wonderland), Robins Hill Rd (15835 Robins Hill Rd), Jolliffe (50 Atlantic Crt), Churchill Logistics (3334 White Oaks Rd), Churchill Logistics (1550 Global Drive), LHSC (825 Commissioners Rd), Western Fair (865 Florence St)

(3334 White Oaks Rd), Churchill Logistics (1550 Global Drive), LHSC (825 Commissioners Rd), Western Fair (865 Florence St)

[2] TD Bank (3029 Wonderland Rd), Boys &Girls Club (184 Horton St), Wonderland Mini Storage (3446 Wonderland Rd), London Transit Commission Solar (3508 Wonderland Rd),TD Bank (1663 Richmond St)

[3] Fanshawe Dam

[4] Harvest Power Mustang Generation – not producing yet

[5] LHSC and Labatt's

[6] Casco and Fort Chicago

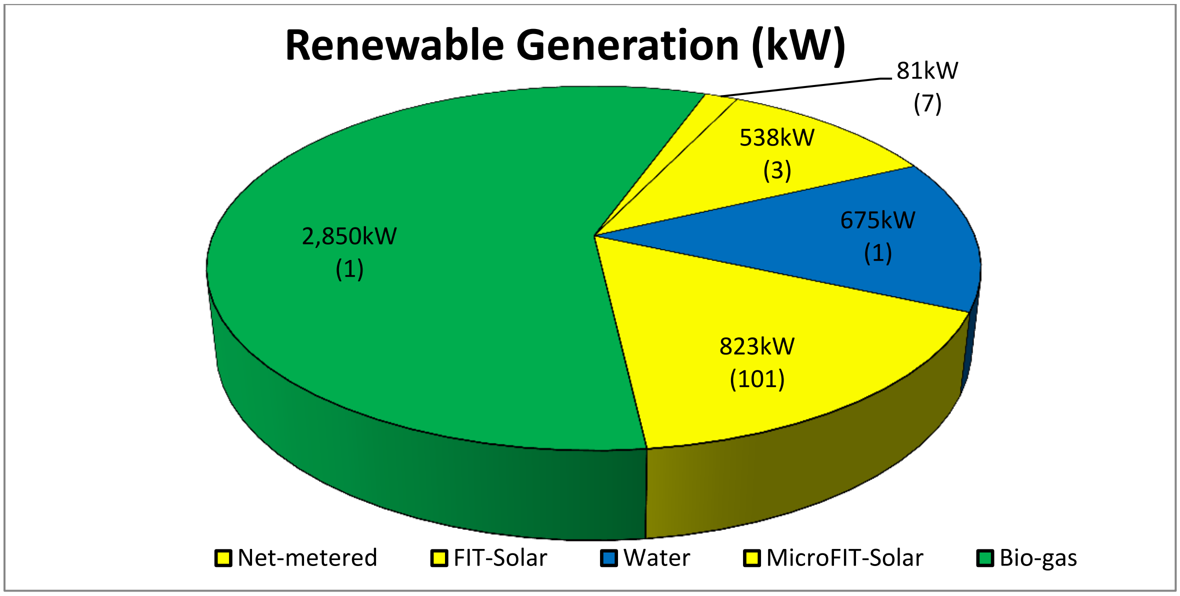

Figure 2: Renewable Generation

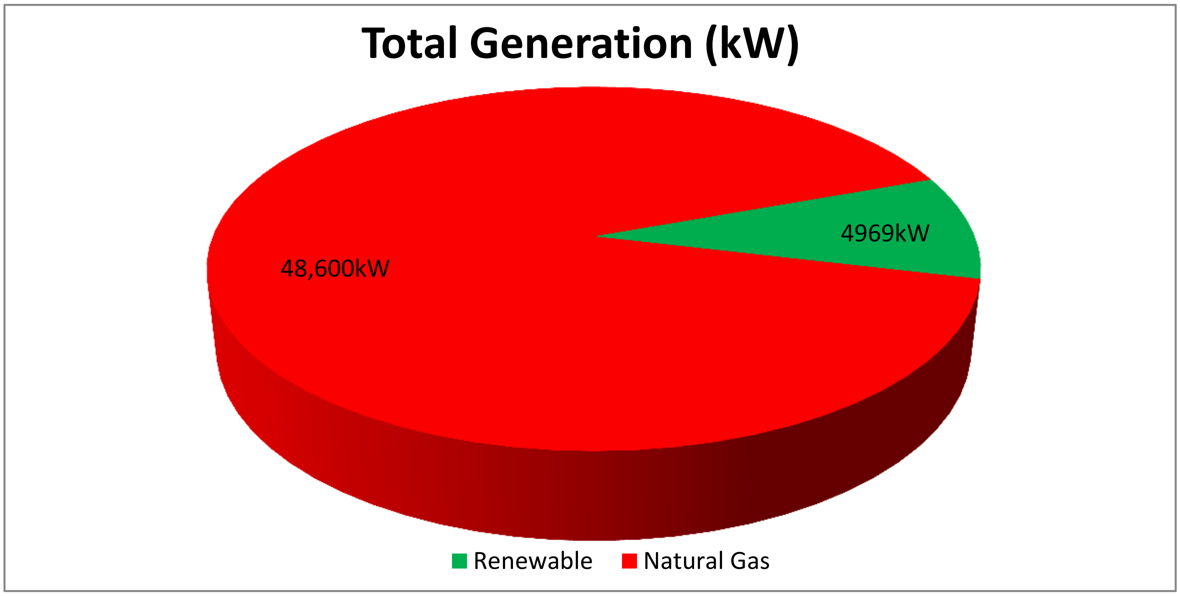

Figure 3: Total Generation

2.3 Renewable Generation Programs at London Hydro

London Hydro has demonstrated support for the government's green initiative by partnering with several entities on projects, in highly visible London locations to demonstrate support and get the message out to the public.

Located in London Hydro territory are seven (7) joint venture microFITs, for a total size of 70kW of generation. These microFITs consist of one (1) solar rooftop and six (6) ground mounted tracker installations. One (1) other location, which consists of a 10kW ground mounted tracker, is wholly owned by London Hydro. London Hydro has also made significant investments in two (2) industry involved FIT projects totaling 350kW. Both projects are roof top mounted units with the 100kW sized project slated for the end of July connection and the 250kW sized project having an in-service date near the end of August 2012.

MicroFIT #	Orientation	Sole/Joint Ownership	Size (kW)
FIT-MR9NB2Z	**Roof Top Mounted**	**Partner**	**10**
FIT-MFD4FYV	**Ground-Mounted Tracker**	**London Hydro**	**10**
FIT-ME4YQZT	**Ground-Mounted Tracker**	**Partner**	**10**
FIT-MM23CJV	**Ground-Mounted Tracker**	**Partner**	**10**
FIT-MFKNCBP	**Ground-Mounted Tracker**	**Partner**	**10**
FIT-MVIH474	**Ground-Mounted Tracker**	**Partner**	**10**
FIT-M6FTXUQ	**Ground-Mounted Tracker**	**Partner**	**10**
FIT-M2ZQN2I	**Ground-Mounted Tracker**	**Partner**	**10**
Total Size			**80**

FIT (Future Connection)	Orientation	Sole/Joint Ownership	Size (kW)
FIT-F59T0WZ *	**Roof Top Mounted**	**Partner**	**100**
FIT-FKEU5QG **	**Roof Top Mounted**	**Partner**	**250**

Table 3: Listing of Renewable Generation Programs at London Hydro

* Connection Date July 31/12

** Connection Date Aug 31/12

3. Challenges Associated with Incorporating DG in an Urban Utility

3.1 Operating Flexibility

LDC's have granted generators a connection to their system based on a 20-year contract between the OPA and the generator. London Hydro's system is constantly evolving due to a variety of sources such as customer load growth or reduction (influenced by the local economy, housing, etc.), voltage conversions, system expansions, etc; often these require long term re-configuration of the system for optimal system performance. It is unlikely for an urban LDC to be able to guarantee their system will not see a major re-configuration over the 20-year generator contract. There is a possibility at some point over the 20-year contract a generator may end up being connected to a different TS. In order to keep generators connected to an open TS it may result in significant capital expenditures. London Hydro ratepayers may have to absorb 100% of the cost for reconnection of generators. As a result, LDC's now have to consider the impacts of distributed generation that could make future system re- configurations impractical or less than optimal.

Currently, the main restriction to re-configuring the system when it involves generation is the inability to move generation onto a different TS due to short circuit capability at Hydro One owned transformer stations. Protection modification and studies would also be required to move the generator. Correcting this situation has the potential to cost millions of dollars. Consequently the LDC would no longer be capable to conduct its planning activity to optimize the design of the distribution system for efficiency and reliability based on customer load.

3.2 Protection equipment

As the amount of connected generation on a feeder increases beyond 50% of the feeder minimum load, additional protection equipment is required. This equipment, such as TT/DGEO[7], provides protection to the generator and surrounding customers by ensuring that the generator goes off-line and does not island during the de-energization of the distribution system it is connected to. It also prevents the TS breaker from closing in and re-energizing a generator that has lost synchronism with the utility after a temporary de-energization. This protection only exists on the generator's normal supply circuit; therefore, if the system is temporarily reconfigured the protection will not be available on the new supply feeder and the generator will have to cease operation.

3.3 Overcurrent Protection Considerations

Studies need to be performed to determine if equipment requires upgrading to allow the system to operate properly under fault conditions (i.e., safely interrupt short circuit currents). In the past, protection engineers designed systems for current flow in one direction. As a result it was not necessary to install relays that would differentiate between reverse current flow and normal current flow. Consequently most relays in operation today will trip with current flow in either direction. This creates a problem when the amount of generation on a given feeder can provide enough reverse short circuit current to a fault on an adjacent feeder thereby inadvertently tripping the breaker on both the faulted and the unfaulted circuit, i.e. the circuit that has the generator connected.

Another issue is that contribution into a fault from multiple current sources (created by generators connected to the system) can desensitize the TS relays. Each source will contribute different fault currents depending on their proximity to the fault location and equivalent impedance. As a result the amount of fault contribution from the TS will be reduced. This can result in the inability of the breaker to properly operate for a feeder end fault.

3.4 Fault Location Techniques

London Hydro has main feeder fault detection on over 140 switchable devices. If generation becomes significantly large, the fault indicator functionality could actually slowdown restoration since more than one source will be feeding into the fault. This multiple source scenario could result in fault indicators showing indication from several different directions thereby confusing the crews and slowing down restoration.

[7] TT/DGEO is a traditional method of communicating the status of a generator connection between the breaker at the transformer station and the physical location of the generator.

3.5 Worker Protection

With the advent of small distributed generation, guaranteeing worker protection is becoming more onerous and time consuming. Since DG is considered an active source of voltage London Hydro requires a visible disconnect with each and every generator. The consequences of DG are that our crews, before performing work on a particular section of line, must ensure that all potential sources of energy (DG's) must be isolated for worker safety. To achieve this, crews must open the utility disconnects at each generation source in their work zone; once the work is completed the crews must again revisit each location to reconnect the generators.

4. Requirements of a Basic Plan

4.1 Consultations

LDC's are required to consult with the OPA and Hydro One in preparing their Basic GEA Plans. The two sections below describe London hydro's interactions with the respective agencies.

4.1.1 Hydro One Consultation

As part of our mandate London Hydro is in constant communication with Hydro One. These meetings take the form of webinars or "in person" meetings; for example London Hydro meets quarterly with Hydro One's DG working group. These meetings cover many issues relevant to LDC's and their interactions with Hydro One and embedded generators. One specific subject that required several meetings was in regards to upgrading Clarke TS to accommodate DG.

There have also been several opportunities to meet on several specific DG projects of a larger nature, for example Fort Chicago, Harvest Power Mustang Generation, German Solar, London Health Science Centre, etc. In addition, there have also been many discussions and correspondence via email and telephone regarding transmission constraints. For instance the Buchanan Longwood Input (BLIP) which deals with transmission flows east to west and how this has prevented larger FIT projects from moving ahead in the London area and southwest of London. This limitation is mainly due to several large wind projects that received contracts previously. London Hydro's understanding is that the building of the Milton Bruce line, which was just completed at the writing of this report, and also the transmission line upgrade west of London between Lambton and Longwood, to be completed 2014, will help to alleviate this situation and free up more generation capacity.

4.1.2 OPA Consultation

London Hydro has participated in over 25 OPA webinars during the program launch and/or subsequent re-launching. The OPA attended a planning meeting at our offices on June 20th, 2012. London Hydro has also had frequent contact with the OPA's Procurements and Contracts departments as well as their Planning department.

4.2 Expenditures – Five-Year Horizon

London Hydro is not looking to recover any costs at this point since to-date there has not been any connections which required a capital contribution from London Hydro.

The Basic Plan must cover a five-year horizon and include information regarding any capital expenditures and OM&A expenditures related to DG. Where the distributor is seeking to recover costs related to the connection of renewable generation from ratepayers, the plan must contain detailed costing information for specific projects for the first year of the plan at a minimum. If detailed cost information is not available for years 2-5 the Board will not be able to assess and approve cost recovery for the anticipated expenditures in the later years of the submitted Basic GEA plan.

Since London is a mainly urban environment with high-density loads London Hydro's present distribution system infrastructure can support a significant amount of renewable generation. In addition, with increased land use restrictions and no wind projects slated in the London Hydro service territory, it is unlikely any system expansions/upgrades will be required over the five-year horizon. There have been over 300 application requests and only three need to connect to an unserviced premise; therefore these may require a system expansion. To-date however, none of these three proponents have moved forward with their project. Therefore, there is no premise on which to predict future capital contributions for renewable generation. For the reasons stated above, at this point, London Hydro is not seeking compensation as there is no commitment indicated by the larger generation projects that require a system expansion or an upgrade.

4.3 Main Elements

4.3.1 Current Assessment of the System

One of the requirements of a GEA plan is to determine London Hydro's capability to accommodate renewable generation for feeders where the OPA has received applications.

The OPA may have received over 300 applications in London Hydro's territory, as stated above; however currently LDC's only have access to those that have been granted a conditional contract, which is a total of 18 (as of May 31, 2012). Now that Clarke TS has been upgraded there are only 2 projects that cannot go ahead due to constrained TS's. Of the remaining 16 projects listed by the OPA, 4 are already connected, and the rest can easily be accommodated within our system.

4.3.2 Limitations in Connecting DG

There are several limitations to connecting generation within London Hydro's service territory. Beginning with the transmission system, the following stations cannot accept any generation due to short circuit capacity:

- Buchanan Y bus
- Nelson JY bus
- Nelson KP bus
- Talbot DESN 1 BY bus

Currently, London Hydro has the following restrictions due to the amount of existing generation on a single feeder.

- Feeder 26M53 out of Talbot TS (Fort Chicago 18.8MW)
- Feeder 19M26 out of Buchanan TS (CASCO 15MW)

4.3.3 Expenditures Related to Renewable Generation Connections in Approved Capital Plans

London Hydro has no specific expenditures for renewable generation projects acknowledged in our approved capital plans. Continued investment is being made in strategic areas of the system to ensure that capacity is available to meet present and future demands. Significant areas of investment include line reinforcement to facilitate the redevelopment of an existing transformer station along with enhancements in capacity near the southern portion of our distribution grid to accommodate existing loads and provide acceptable levels of power quality. These investments may enable future projects to proceed.

4.3.4 Unique Challenges pertaining to London Hydro

Exclusive to London Hydro and a handful of other utilities, the downtown secondary mesh network poses some unique challenges. The downtown network is a system of intertied secondary cables supplied by 94 network transformers which are fed by 5 separate primary feeders. In addition each transformer has a network protector which prevents reverse current from flowing backward onto the primary system; this is an extremely important protection system from a safety and reliability perspective. If there is too much generation on a particular transformer it can cause reverse current flow and trip the network protector thereby de-energizing that transformer and removing it from the system, leading to potential overvoltage. Network protectors are calibrated to be very sensitive to reverse current flow, this results in a very reliable system. Currently generation is limited to microFIT's (<10kW) and even then it is studied on a case by case basis.

5. Planned Development of the System

5.1 Estimate of Future Generation Projects

Every LDC is required to estimate the number of generators and the total MW of connected generation that can be anticipated over the next five years, based on current generation connection applications. This is challenging since London Hydro is only aware of the 18 contracts that the OPA has awarded since the program launch in 2009. Unfortunately the contract awarding process is not transparent to LDC's and therefore it is difficult to determine if more contracts will be or are being awarded unless they are posted on the OPA LDC portal.

To-date London Hydro has received more than 300 applications for connection (IFAs) since the program launch while the OPA has published only 18 projects for a total of 3.5MW. **Therefore a best estimate using a linear approach is to assume that over the next five years it is possible to see 45 new projects for a total of over 8MW. This is not taking into account the possible dampening effect that the new pricing structure may have on applications and projects going forward with the release of FIT 2.0.**

5.2 Planned Infrastructure Spending to Accommodate Renewable Generation

London Hydro does not foresee any required expenditures over the next five years to accommodate renewable generation unless a project comes forward that requires an expansion or voltage upgrade. As stated previously, almost all applications have been load connected generation (=<500kW) not requiring any LDC investment and the remaining projects (>500kW) have not received OPA contracts, nor has London Hydro received any indication that they are going to proceed. London Hydro has received a couple inquiries that would require upgrading a line from 8.32kV to 27.6kV; however doing this in advance of an OPA contract award is not prudent since London Hydro does not know if the projects will pass the TAT; we have no other reason for upgrading the line. None of the proceeding analysis absolves London Hydro from connecting such projects, therefore if required London Hydro will apply for cost reimbursement after the fact.

There is a continued investment being made in strategic areas of the system to ensure that capacity is available to meet present and future demands. Significant areas of investment include line reinforcement to facilitate the redevelopment of an existing transformer station along with enhancements in capacity near the southern portion of our distribution grid to accommodate existing loads and provide acceptable levels of power quality. These investments may enable future projects to proceed.

5.3 Calculation of Direct Benefits

As a result of the proceeding, at this time London Hydro is not pursuing any cost recoveries from the provincial rate payers (Board Policy EB-2009-0349, Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09). Should a situation arise where this is necessary London Hydro will provide the documentation at that time.

5.4 Prioritizing Expenditures to Accommodate Renewable Generation Connections

Due to the lack of need for expansions resulting from renewable generation, expenditures will be prioritized as projects materialize. Business cases to support prioritizing of capital expenditures for new infrastructure or refurbishment of existing plant take into consideration the ability of the system to accept generation. As stated throughout this whole document, since London is a mainly urban environment with high-density loads London Hydro's present distribution system infrastructure can support a significant amount of renewable generation.

5.5 Conclusion

This Basic GEA Plan outlines London Hydro's effectiveness in being able to connect renewable generation facilities. As well, the Plan identifies the many renewable generation projects in which London Hydro itself has invested.

London Hydro has been successful in connecting many approved FIT and microFIT projects to date. London Hydro wants to continue this trend by continuing to work closely with our customers to ensure successful implementation of renewable generation within the City of London in support of the GEA program.

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Appendix A: MicroFIT and FIT Projects Connected up to End of May 31, 2012

Table 4: FIT Projects

Type of Renewable Generation	Nameplate Capacity (kW)
Solar Photovoltaic	120
Solar Photovoltaic	168
Solar Photovoltaic	250
Total	538

Table 5: MicroFIT Projects

Customer Class	Type of Renewable Generation	Generation Size (kW)	Rooftop or Ground Mounted	Connection Date
Residential	Solar Photovoltaic	3	Rooftop	30-Dec-09
Residential	Solar Photovoltaic	10	Rooftop	1-Apr-10
Residential	Solar Photovoltaic	5	Rooftop	26-Apr-10
Registered Charity	Solar Photovoltaic	10	Rooftop	30-Apr-10
Commercial	Solar Photovoltaic	10	Rooftop	30-Apr-10
Residential	Solar Photovoltaic	2	Rooftop	19-May-10
Residential	Solar Photovoltaic	2	Rooftop	10-Jun-10
Residential	Solar Photovoltaic	4	Rooftop	10-Aug-10
Institutional	Solar Photovoltaic	2	Rooftop	24-Aug-10
Residential	Solar Photovoltaic	10	Ground mounted	23-Sep-10
Institutional	Solar Photovoltaic	9	Ground mounted	5-Oct-10
Commercial	Solar Photovoltaic	5	Rooftop	7-Oct-10
Commercial	Solar Photovoltaic	5	Rooftop	12-Oct-10
Commercial	Solar Photovoltaic	10	Rooftop	18-Oct-10
Residential	Solar Photovoltaic	3	Rooftop	20-Oct-10
Residential	Solar Photovoltaic	4	Rooftop	22-Oct-10
Residential	Solar Photovoltaic	4	Rooftop	28-Oct-10
Residential	Solar Photovoltaic	5	Rooftop	29-Oct-10
Commercial	Solar Photovoltaic	10	Rooftop	16-Nov-10
Commercial	Solar Photovoltaic	10	Rooftop	19-Nov-10

Residential	Solar Photovoltaic	5	Rooftop	26-Nov-10
Residential	Solar Photovoltaic	5	Rooftop	26-Nov-10
Residential	Solar Photovoltaic	1	Rooftop	1-Dec-10
Commercial	Solar Photovoltaic	10	Rooftop	3-Dec-10
Residential	Solar Photovoltaic	4	Rooftop	3-Dec-10
Commercial	Solar Photovoltaic	10	Rooftop	10-Dec-10
Residential	Solar Photovoltaic	6	Rooftop	17-Dec-10
Commercial	Solar Photovoltaic	10	Rooftop	21-Dec-10
Residential	Solar Photovoltaic	10	Rooftop	22-Dec-10
Residential	Solar Photovoltaic	10	Ground mounted	23-Dec-10
Institutional	Solar Photovoltaic	10	Rooftop	23-Dec-10
Commercial	Solar Photovoltaic	5	Rooftop	23-Dec-10
Residential	Solar Photovoltaic	10	Rooftop	24-Dec-10
Institutional	Solar Photovoltaic	10	Rooftop	30-Dec-10
Residential	Solar Photovoltaic	10	Rooftop	31-Dec-10
Commercial	Solar Photovoltaic	10	Ground mounted	21-Jan-11
Residential	Solar Photovoltaic	4	Rooftop	2-Mar-11
Commercial	Solar Photovoltaic	10	Ground mounted	2-Mar-11
Commercial	Solar Photovoltaic	10	Ground mounted	3-Mar-11
Residential	Solar Photovoltaic	3	Rooftop	24-Mar-11
Residential	Solar Photovoltaic	1	Rooftop	5-Apr-11
Residential	Solar Photovoltaic	6	Rooftop	19-Apr-11
Commercial	Solar Photovoltaic	10	Rooftop	21-Apr-11
Residential	Solar Photovoltaic	9	Rooftop	20-May-11
Commercial	Solar Photovoltaic	10	Ground mounted	20-May-11
Commercial	Solar Photovoltaic	10	Rooftop	27-May-11
Residential	Solar Photovoltaic	8	Rooftop	27-May-11
Residential	Solar Photovoltaic	7	Rooftop	27-May-11
Commercial	Solar Photovoltaic	10	Rooftop	2-Jun-11
Commercial	Solar Photovoltaic	10	Ground mounted	2-Jun-11
Commercial	Solar Photovoltaic	10	Ground mounted	3-Jun-11
Commercial	Solar Photovoltaic	10	Ground mounted	3-Jun-11

Commercial	Solar Photovoltaic	10	Ground mounted	3-Jun-11
Community	Solar Photovoltaic	10	Rooftop	8-Jun-11
Commercial	Solar Photovoltaic	10	Rooftop	8-Jun-11
Residential	Solar Photovoltaic	6	Rooftop	8-Jun-11
Residential	Solar Photovoltaic	10	Rooftop	10-Jun-11
Commercial	Solar Photovoltaic	10	Ground mounted	10-Jun-11
Residential	Solar Photovoltaic	5	Rooftop	17-Jun-11
Commercial	Solar Photovoltaic	10	Rooftop	27-Jun-11
Residential	Solar Photovoltaic	10	Rooftop	29-Jun-11
Residential	Solar Photovoltaic	10	Rooftop	29-Jun-11
Residential	Solar Photovoltaic	10	Rooftop	29-Jun-11
Residential	Solar Photovoltaic	10	Rooftop	29-Jun-11
Residential	Solar Photovoltaic	10	Rooftop	29-Jun-11
Commercial	Solar Photovoltaic	10	Ground mounted	30-Jun-11
Residential	Solar Photovoltaic	7	Rooftop	5-Jul-11
Commercial	Solar Photovoltaic	10	Rooftop	26-Jul-11
Residential	Solar Photovoltaic	9	Rooftop	8-Aug-11
Residential	Solar Photovoltaic	2	Rooftop	11-Aug-11
Residential	Solar Photovoltaic	9	Rooftop	17-Aug-11
Residential	Solar Photovoltaic	10	Rooftop	19-Aug-11
Commercial	Solar Photovoltaic	10	Rooftop	26-Aug-11
Residential	Solar Photovoltaic	10	Rooftop	7-Sep-11
Residential	Solar Photovoltaic	10	Ground mounted	9-Sep-11
Residential	Solar Photovoltaic	6	Rooftop	30-Sep-11
Commercial	Solar Photovoltaic	10	Rooftop	12-Oct-11
Residential	Solar Photovoltaic	5	Rooftop	12-Oct-11
Residential	Solar Photovoltaic	6	Rooftop	17-Oct-11
Residential	Solar Photovoltaic	10	Rooftop	19-Oct-11
Institutional	Solar Photovoltaic	10	Rooftop	20-Oct-11
Residential	Solar Photovoltaic	10	Rooftop	20-Oct-11
Residential	Solar Photovoltaic	6	Rooftop	24-Oct-11
Commercial	Solar Photovoltaic	10	Rooftop	27-Oct-11

Residential	Solar Photovoltaic	10	Rooftop	9-Nov-11
Institutional	Solar Photovoltaic	10	Ground mounted	5-Dec-11
Residential	Solar Photovoltaic	6	Rooftop	6-Dec-11
Institutional	Solar Photovoltaic	10	Wall mounted	22-Dec-11
Commercial	Solar Photovoltaic	10	Rooftop	27-Jan-12
Commercial	Solar Photovoltaic	10	Rooftop	27-Jan-12
Commercial	Solar Photovoltaic	10	Rooftop	27-Jan-12
Commercial	Solar Photovoltaic	10	Rooftop	27-Jan-12
Commercial	Solar Photovoltaic	10	Rooftop	8-Feb-12
Residential	Solar Photovoltaic	10	Rooftop	23-Feb-12
Commercial	Solar Photovoltaic	10	Ground mounted	19-Mar-12
Residential	Solar Photovoltaic	10	Rooftop	19-Mar-12
Residential	Solar Photovoltaic	10	Rooftop	21-Mar-12
Commercial	Solar Photovoltaic	10	Rooftop	26-Mar-12
Residential	Solar Photovoltaic	10	Rooftop	27-Mar-12
Residential	Solar Photovoltaic	10	Rooftop	12-Apr-12
Commercial	Solar Photovoltaic	10	Rooftop	23-May-12
Total		823		

APPENDIX 2H – OPA LETTER OF COMMENT RE: GEA PLAN

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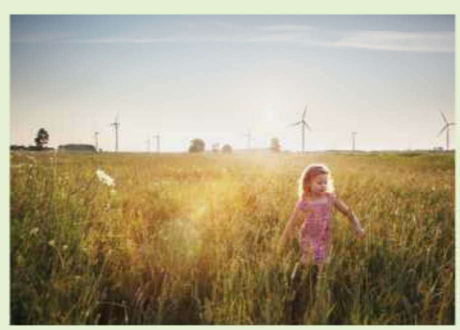
OPA Letter of Comment:

London Hydro Inc.

Basic Green Energy Act Plan

August 10, 2012



ONTARIO POWER AUTHORITY

Introduction

On March 25, 2010, The Ontario Energy Board ("the OEB") issued its Filing Requirements for Distribution System Plans. As a condition of Licence, Ontario Distributors are required to file a Green Energy Act Plan as part of their cost of service application.

The Filing Requirements distinguish between Basic and Detailed Green Energy Act Plans ("Plan" or "GEA Plan") and outline the specific information and level of detail which must be provided for each type of Plan. Recognizing the importance of coordinated planning in achieving the goals of the *Green Energy and Green Economy Act, 2009* (the "GEA"), distributors must consult with embedded and host distributors, upstream transmitters and the OPA in preparing their Plans. For both Basic and Detailed Plans, distributors are required to submit as part of the Plan, a letter of comment from the OPA.

The OPA will review distributors' Basic Plans to ensure consistency with regard to FIT and microFIT applications received, as well as with integrated Plans for the region or the system as a whole.

London Hydro Inc. - Basic Green Energy Act Plan

The OPA has reviewed the Basic GEA Plan from London Hydro Inc. ("London Hydro") dated June 25, 2012, with a revised date of July 27, 2012 and has provided its comments below.

OPA FIT/microFIT Applications Received

London Hydro's GEA Plan indicates that to date 106 microFIT projects totaling 0.838 MW of capacity and 3 Solar photovoltaic FIT projects totaling 0.538 MW have been connected in London Hydro's service territory. These projects have been indicated in Table 1: Distribution Generation Activity (<10kW) on page 4, and Table 4: FIT projects in Appendix A. Also in section 5.1, it indicates that more than 300 applications for connection have been received since the program launch.

To date, the OPA has processed 277 microFIT applications totalling approximately 2.42 MW of capacity in London Hydro's service territory. Of these, approximately 0.84 MW have been offered a contract as of July 2012. Additionally, the OPA has received and offered contracts to 26 capacity allocation exempt FIT applications, totalling approximately 5 MW that have identified themselves as connecting within London Hydro's service territory. Of these, 16 applications totaling approximately 3.36 MW of capacity remained active as of July 2012.

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Upstream Transmission Constraints

London Hydro's GEA Plan indicates that four stations cannot accept any generation due to short circuit capacity in section 4.3.2 on page 9. This is consistent with the OPA's information.

The updated Transmission Availability Table for Small FIT 2012 available on the OPA's FIT website as follows: http://fit.powerauthority.on.ca/sites/default/files/TAT%20Table%20Final%20-%20April%205%20for%20posting.pdf

Economic Connection Test

The OPA received a directive dated April 5, 2012 from the Minister of Energy with respect to the Feed-in Tariff Program Review. The directive states that "[g]iven the transmission projects planned through the Long Term Energy Plan and changes to the FIT Program, the OPA shall not run the Economic Connection Test ". A link to the full directive is provided on the OPA's website:
http://www.powerauthority.on.ca/sites/default/files/page/FIT-ReviewApril-2012.pdf

Opportunities for Integrated Solutions

There are no known corresponding expansions among neighbouring LDCs that could be addressed through integrated transmission solutions at this time.

Conclusion

The OPA finds that London Hydro's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date.

The OPA appreciates the opportunity to comment on London Hydro Inc.'s Basic GEA Plan.

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APPENDIX 2I – INFORMATION TECHNOLOGY STRATEGY 2012 TO 2014

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Information Technology Strategy
Fiscal Year 2012-2014

London
Hydro

Prepared October 2011

Table of Contents

Section 1. Introduction

1.1. Vision

Contribute to London Hydro's vision and mission by optimizing IT through effective planning, delivery of technology projects and operations on time, on budget and within expected quality for London Hydro customers.

1.2. Mission Statement

Our mission is to provide technology leadership while delivering cost effective and flexible technology solutions and services to London Hydro's business users and customers.

1.3. Principles

In pursuit of the IT Services vision and mission we will:

- Obtain in depth understanding of customers' needs to ensure requirements are properly defined and considered to deliver quality solutions
- Define multi-year forward thinking plans for technology integration, considering overall life-cycle cost of technology solutions and investments
- Deliver technology solutions to enable London Hydro to be an industry leader with unique and innovative IT solutions
- Define, maintain and refine processes and methods to ensure consistency and quality in technology solution deliverables
- Establish and utilize standards and longer term partnerships in IT service procurement, encouraging competitive pricing and strong service management
- Establish business partnerships to build trust within the business user community and ensure acceptance of delivered solutions
- Strive to provide equal consistent levels of service to all business areas
- Continuously evaluate our application and infrastructure landscapes for opportunities to simplify and consolidate processes to minimize overhead
- Develop and utilize internal resource capabilities to create a Centre of Excellence in the core business systems and avoid reliance on third parties
- Position ourselves as a progressive and agile IT organization to easily adapt to changes and deliver new capabilities and service models to the business

1.4. Culture

Within the IT services organization, we aim to create a culture of creative and innovative problem solving and multi-disciplinary staffing. From an IT perspective, London Hydro's size can create problems of scale – the organization and data processing requirements are such that larger scale solutions are sometimes required, yet there is a high entry cost to the systems that such solutions often imply.

To achieve success, we need to deliver solutions and support in a more efficient and effective manner, leveraging the agility we have compared to larger organizations. This involves utilizing staff in multiple roles throughout system lifecycles, encouraging a broader perspective and understanding of systems and the business processes they are created to support, which can be facilitated through improved internal communication and cross-training of processes between current resources. In conjunction with this, we need to encourage more creative and innovative use of the systems already available to minimize overheads and help to simplify the technology landscape.

1.5. Background

London Hydro is an electricity distribution company, serving the area of London, ON and is a public corporation with a sole shareholder - the Corporation of the City of London. London Hydro distributes electricity to approximately 150,000 customers within its franchise service territory; its distribution network spans some 420 square kilometers within the City of London. As a community corporation, London Hydro subscribes to the principles of safety, reliability of supply, customer care, and public trust.

London Hydro operates within a complex electricity market and regulatory environment in the Province of Ontario. This necessitates significant investment not only in the operational aspects of a 'wires' company, but also in the areas of meter to cash (including metering, VEE, billing, collections) and market settlements processes.

London Hydro's IT organization, comprised of the Project Management Office and IT departments exists to implement and maintain business IT systems and infrastructure to support all areas of the organization, which broadly covers Engineering, Operations, Metering Services, Customer Services, Finance and Human Resources.

Section 2. Condition Assessment

2.1. Application Landscape

London Hydro's application landscape can been broadly divided into three categories[1] of business systems:

- Enterprise systems support major or fundamental business process areas and operations, including the SAP Customer Information System, Intergraph Geographic Information System and JDEdwards Financials/ERP. These systems represent substantial technology platform and financial investment.
- Specialized systems primarily support the processes of Category A systems, through data collection, integration of systems or narrower focused processes. These systems represent smaller technology and financial investment.
- Outside of the primary and secondary systems are those generally disconnected from other systems and created on an ad-hoc needs basis outside of the support of IT services. These are often referred to as 'cottage industry' systems.

A logical connectivity diagram of the current landscape may be found in Appendix A.

2.1.1. Customer Information System

London Hydro went live with the current SAP Customer Information System in June 2009, replacing the old CIS*Ontario* system. Since that time, focus has been primarily on stabilization of the core system functionality and development of incomplete processes. Several areas of functionality saw redesign efforts in 2010 to resolve outstanding issues, including the print workbench bill print extract process and collections functionality. These efforts have continued through 2011 with projects initiated to redesign EBT billing and settlements functions and annual security deposit assessment, both on schedule to go live in 2012. The key objective with these initiatives is to allow London Hydro to make better use of SAP functionality, reducing the volume of custom developments, while resolving outstanding issues.

Development of new functionality to implement time of use billing and interfaces to the provincial MDM/R service was completed in 2011 and smart meter data is being communicated and synchronized with the Provincial MDM/R. There is still additional work to complete in the smart meter space, including developments to support requirements set out by Measurement Canada which due to scheduling of the certification process, were not able to be considered in the initial development. This work is already well underway and scheduled to go live in Q1 2012, aligned with the IESO deployment of the MDM/R update and London Hydro's mandated ToU deadline.

[1] *Note that these categories represent a method of classification for technology platform and financial investments, not the level of importance or criticality of a system to business operations.*

Reporting continues to be an ongoing concern with regards to the Customer Information System and across the entire application landscape. Due to limitations of the standard SAP query tools and time/effort requirements to produce reports in the SAP ABAP programming language, many queries are written directly against the underlying SAP database, while some simpler queries do utilize the built in SAP tools and others have been implemented in ABAP. Work has begun on defining a reporting strategy for execution through 2012, 2013 and beyond to ensure effective use is made of the tools available and ensure reporting quality.

The SAP environment has had several successful software upgrades applied in 2011. The core SAP ECC system itself has been upgraded to Enhancement Pack 5 in support of new AMI capabilities required for the Operational Data Store integration other new capabilities provided by Enhancement Pack 5 still need to be evaluated for future process improvement opportunities. As part of this implementation, the underlying databases were also upgraded from Oracle 10g to 11g.

2.1.2. Geographic Information System

London Hydro introduced GIS technology in 2007, when Intergraph was selected as the GIS vendor to provide a suite of tools to manage our electrical data. Data editing tools were configured for the GIS staff, and a basic map display application was provided to other Engineering & Operations users. With 3 years of use, staff have identified a number of areas where efficiencies can be achieved and reporting accuracy can be improved.

To address the need for a more efficient and reliable corporate-wide GIS system, GIS enhancement project has been launched at London Hydro. It spans 3 years (2010, 2011 & 2012), with the data cleansing and conversion initiated in late in 2010. In 2011, the majority of GIS enhancement projects have been accomplished as planned. Software Upgrade, Connectivity projects have been fully finished and in production. Engineering project is rolling into production and full training has been scheduled to finish in early November. CYME Phase 1 is on schedule for Oct. 31 closure and phase 2 ODS loading integration will be extended to early 2012. GIS remaining projects are on track and the majority of milestones committed to be signed off in 2011 with a few remaining milestones extending into early 2012.

However, during the test phase, some GIS data deficiency has been identified for CYME integration and it requires some internal effort to clean up. A full CYME equipment database is also required to be in place before CYMDIST fully goes live. An internal plan has been developed to address these issues and the target is to get all the data fixed before the end of year. Two sample feeders are clean and ready for CYME simulation and testing purpose.

London Hydro regularly needs to incorporate outside sources of information from the City of London, contractors and consultants. New tools or new processes are under development and expected to be in place before the year end, to streamline data integration from different sources.

2.1.3. JDEdwards Financials

JD Edwards (JDE) EnterpriseOne is the primary financial reporting system at London Hydro. It was originally implemented (as JDE World) in 1997 and is used by the Finance Department for General Ledger, Accounts Payable and Fixed Assets and by other departments for Purchasing, Work Orders and Materials Management.

It is a multi-tiered application comprising a presentation layer on client desktops, a server application layer and a database layer. In 2010 the server application was migrated from the Sun platform to Windows/VMWare and the database was migrated from Oracle 9i on Sun to Oracle 11g on Linux. The underlying tools release was also upgraded to the latest available version as part of this project. Though a decision was made to remain with the existing client application version the new tools release provides the flexibility to upgrade to a newer version if desired or deemed necessary.

In 2011 the costs associated with JDE were reduced by switching from vendor maintenance with Oracle to a third-party support provider. A one year contract was signed with Spinnaker Support LLC with the option of renewal at the same flat rate for up to five years. This provides a better than 50 percent savings over the annual invoice from Oracle. Spinnaker specializes in supporting all versions of JDE on multiple platforms with the added benefit of a dedicated team assigned to each client's account. It should be noted though, that this cost reduction comes with some risk as future upgrades would not be possible without a penalty payment to resume maintenance/support through Oracle.

As expected the compliance date for conversion to International Financial Reporting Standards (IFRS) was deferred to January 1, 2012. Efforts are underway to complete the transition from Canadian GAAP to IFRS reporting with good progress made to date.

Opportunities remain to achieve further efficiencies within JDE, such as automation of Purchase Order Generation. Electronic File Transfer (EFT) for payments to vendors is expected to be implemented by the end of 2011.

Insight2JDE (formerly Inquiry Suite), a third-party product, is used as a reporting tool with JDE and in the Spring of 2011 the software was upgraded to the latest version. As part of our reporting strategy development, the future use of this tool will be considered in the roadmap for reporting system changes.

2.1.4. Operational Data Store

Design and development of London Hydro's meter data Operational Data Store (ODS) has been ongoing through 2011, with delivery of the major components into the production landscape occurring in two phases during November and December. This system will provide London Hydro with additional control over smart meter data and facilitate more efficient interoperability with the Provincial MDM/R by reducing the need to utilize the MDM/R's remote user interface. The ODS will also enable the use of hourly interval data to facilitate distribution planning and eventually provide an alternate data source for web presentment to customers.

2.1.5. Secondary Systems

The Sensus FlexNet RNI system, which functions as a head-end to London Hydro's AMI system is now operational as a production system, sending smart meter data to the MDM/R on a daily basis. Integration for master data synchronization between SAP and the RNI was put in place as an interim measure while development in the ODS project is intended to provide a long-term master data synchronization solution.

In late 2009, London Hydro sought to extract early value from deployed AMI infrastructure prior to implementation of AMI and smart meter processes, since several towers and some thousands of meters were deployed in the field. An innovative approach was created utilizing existing meter read interfaces and an integration process to achieve Automated Meter Read (AMR) operation which is transparent to the SAP CIS, thereby reducing implementation cost. Through 2010, all deployed smart meters were transitioned to this process, so that over 130,000 meters are now being read remotely each month. In 2011 the transition of smart meters to AMI processes and utilization of hourly data began with the synchronization of meter data with the MDM/R and London Hydro is now communicating hourly meter data for more than 135,000 meters daily to the MDM/R in preparation to begin Time of Use billing prior to the March 31st 2012 deadline imposed by the Ontario Energy Board.

In July 2010, the SAP Utility Customer eServices (UCES) application was deployed, enabling customers to access their account information (such as balance, bill images, consumption) via the London Hydro web site. We continue to have difficulty in finding resources with skills in this application space, which makes ongoing development and changes challenging. The capabilities of the customer self-service application have been extended in 2011 with custom developments outside of the framework of UCES to support presentment of hourly and Time of Use information to customers as part of our customer engagement strategy.

To facilitate recurring reporting requirements, reduce database query performance impacts and cross-system connectivity for data, an informal reporting database or data mart arose in 2009/2010. This has proven useful as an interim transactional and BI reporting type system as well as for interim business process operations such as security deposit assessment. This system will be more formalized as part of the development of our reporting strategy and will likely play in key role in the utilization of Business Intelligence tools. We are currently in the process of evaluating SAP's Business Objects Data Services tools as a centralized repository for data extract and transformation processes in this area.

Though efforts are underway to enhance the functionality of London Hydro's Geographic Information System, there are existing concerns regarding the integration between GIS and the SAP CIS system. With one of the primary objectives of the GIS to provide a strong connectivity model to support future OMS developments, a consistent cross-system data model must be established to enable unambiguous data connectivity and integrity for system integration.

2.1.6. Cottage Industry Systems

Many London Hydro business departments utilize 'cottage industry' type systems on a day to day basis. These often take the form of Microsoft Access databases or sophisticated Excel spreadsheets that have been created within a department to satisfy particular needs not met by the IT supported application landscape.

These systems represent a risk to London Hydro for several reasons:

- Data sources for these systems may not be validated or correctly understood, resulting in business decisions or actions taken on incorrect information.
- Systems are not considered in impact analysis for changes to enterprise and specialized systems, since they are not well defined.
- Systems are not tested for interoperability with new software versions, such as Microsoft Office or Windows, or conflicts with other business applications.
- Systems may be business critical, but are not included in disaster recovery planning or appropriate data backup.

The first steps have been taken in this area towards consolidation with a review of "Kovan's Application" a tool created by a summer student to assist the Electric Meter department with inventory management. The key functions of this application will fit well with the SAP PM and MM modules and we hope to enable this functionality in 2012. More focus is needed though to identify and catalogue other systems and their purposes, since no comprehensive list currently exists. This will provide an initial step towards the consolidation of data and functionality within supported systems.

2.2. IT Infrastructure

2.2.1. Servers and Storage

With the volume of significant changes occurring in London Hydro's SAP landscape, the infrastructure team created a new parallel development landscape to allow AMS and project teams to work independently and on differing timelines. A test system for the Sensus RNI has also been set up to provide a more complete testing environment and allow execution of more end to end test scenarios.

London Hydro's storage systems are provided in two tiers – Tier 1 is targeted at supporting high performance and availability needs of mission critical applications, while Tier 2 supports file server usages and non-production systems. Storage systems have been consolidated to HP SAN systems along with a storage expansion during 2010, with the table below showing the high level storage breakdown.

	Tier	Total Capacity (TB)	Used Capacity 2011Q3 (TB)
HP EVA SAN (FC)	1	67 (last year: 39)	48 (last year: 32)
HP EVA SAN (FATA)	2	21 (last year: 13)	18 (last year: 7.5)

The SAP system data growth is currently averaging over 400GB per month. Taking this into consideration, the infrastructure group will need to concentrate on two primary areas of concern: keeping up with data storage demands and keeping in sync the disaster recovery and backup strategy.

Increasing data storage requirements has a direct impact to the ability to backup data for disaster recovery purposes. A new NEO400S tape library with two LTO4 tape drives was installed in 2010 to help manage nightly backup tasks, but this does not address the long term issues that are faced in this area, which is compounded by London Hydro's original NEO2000 backup tape library reaching end of life in 2011. To resolve the backup dilemma, it will be necessary to establish new strategies for data backup and recovery in the near future.

London Hydro's Citrix farm was initially intended to allow London Hydro staff remote access to applications while away from the office; however, over time this service has expanded to be utilized by business partners and consultants across the business. To facilitate these increasing user demands the Citrix farm has been migrated to a virtualized environment in 2011 providing greater flexibility in scalability, failover and resource management.

2.2.2. Network and Connectivity

In 2009 London Hydro's 3Com edge switches reached their 5-year anniversary date. The product has been stable and reliable but the company has been purchased by HP and the product is being phased out. In 2010, the Infrastructure team under took a review of available products that could meet the dual needs of both the corporate network and the operational network required to support the Smart Metering program. The result of that review was the selection of Juniper firewalls and switches. These devices could be used in both the corporate and harsher environments found in substations and remote equipment rooms.

Juniper firewalls and switches have been deployed to protect the corporate and smart metering networks and provide isolated connectivity to the internet. Asset refreshes have started and 3Com switches are being replaced by Juniper devices between 2012 and 2015. Retired 3Com devices will be stored as replacement parts as part of our self-insure program to reduce maintenance of these assets.

At the core of the network are two Nortel devices. These devices were updated in the first half of 2010 and have been operating without issue. Performance and capacity are excellent and can meet our needs for the next 2 years. Avaya has purchased the rights to these devices from now defunct Nortel and have confirmed support for the next year. Long term viability of maintaining the device is still of concern and the refresh of the core network upgrade has been moved to 2013.

The long term strategy will be to replace the core Nortel switches with devices provided by a common vendor, resulting in a reduction of supported devices in the infrastructure and management of multi-vendor contracts to support a single network and connectivity solution. We will also utilize this time to review with the

City of London opportunities to leverage common vendors, contracts and expertise to improve the quality and cost of service.

In September of 2011, we successfully completed migration of internet services to Bell. This move was driven by two concerns. Rogers was shutting down the legacy infrastructure formerly owned by Group Telecom (GT) that was used to support our internet connectivity. Second, we were able to move to a new pricing model that did not penalize the corporation for growing data upload and download charges. In 2012, we will plan for the implementation of a second diverse internet link would ensure our customers greater reliability accessing web enabled customer service applications and internal corporate internet dependencies such as bank transfers as well as the provincial mandate to move data the MDM/R.

2.2.3. Desktop Services

London Hydro's desktop computing systems are standardized around Hewlett Packard business machines, in particular HP Compaq Business Desktop 5000 series and HP ProBook notebooks. Panasonic ToughBook ruggedized laptops are also supported for outdoor/field use cases. In an effort to reduce costs, desktop systems have had their useful life extended from 3 to 5 years. Current processing requirements can be managed in this manner as much processing actually occurs server-side for many of the business applications and local PC storage requirements are augmented by shared storage on the file servers supported by the SAN.

Starting in 2011, all new desktops and laptops are ordered with Windows 7 unless there is a specific application dependency on Windows XP. Using this opportunistic refresh strategy on new purchases and reimaging of devices when they are to be redeployed, we have upgraded a little over 26% (90 of 346) of the fleet. We are working with individual departments to review their application usage and upgrading to Windows 7 when no application dependencies are present. We anticipate having a third of the installed base updated by the end of 2011. Migration will not be completed until 2014 when applications like GIS and ODS have client versions certified on Windows 7.

Upgrading of office suite of productivity tools to Microsoft Office 2010 was successfully completed during 2011. This was a much more aggressive deployment than the previous Office 2007 deployment and leveraged the new service desk deployment and self-serve capabilities. The entire cycle time took approximately 9 months versus the 2 year cycle on the Office 2003 to 2007 upgrade. No further upgrades to the office suite are planned for the next 2-3 years, though we will be researching the feasibility of open source products, such as OpenOffice/LibreOffice or Star Office, as an option to replace or reduce the dependence on Microsoft Office.

2.2.4. Security and Privacy

With the significant changes in both the application and supporting infrastructure related to the implementation of the new SAP Customer Information System (CIS) and Smart Meter wireless infrastructure our security profile changed. A detailed audit review, by a leading security auditing firm, was completed in August of 2009 and more focused reviews around our internet presence and wireless network have been conducted in late 2010 and in 2011. The review included penetration testing, vulnerability scanning, network intrusion and social engineering.

The original assessment identified several areas of concern and remediation activities have been taking place since that time. The focus has been on reducing all "High" and "Medium High" risk areas to at least a "Moderate" rating. The results of the 2010 and 2011 Security Self-Assessment Ratings are compared below to illustrate the progress towards remediating the "High" and "Medium-High" status in various areas of our infrastructure.

2010 Security Self-Assessment Rating Summary

ASSESSMENT AREA	RATING	ASSESSMENT AREA	RATING
Physical Security	ELEVATED	Wireless Networks	LOW
Network Management and Monitoring	MODERATE	Antivirus and Malicious Code	LOW
Firewall	MODERATE	Intrusion Detection/Prevention	LOW
Authentication	MODERATE	Vulnerability Assessment	LOW
File System	MODERATE	WAN Infrastructure	LOW
Remote Access/VPN	MODERATE	LAN Infrastructure	MEDIUM-HIGH
Network Security	HIGH	Internet Traffic Analysis	LOW
Host Security	HIGH	Documentation	LOW
Content Inspection	MODERATE	Policies	ELEVATED

2011 Security Self-Assessment Rating Summary

ASSESSMENT AREA	RATING	ASSESSMENT AREA	RATING
Physical Security	ELEVATED	Wireless Networks	LOW
Network Management and Monitoring	LOW	Antivirus and Malicious Code	ELEVATED
Firewall	MODERATE	Intrusion Detection/Prevention	LOW
Authentication	MODERATE	Vulnerability Assessment	LOW
File System	MODERATE	WAN Infrastructure	LOW
Remote Access/VPN	ELEVATED	LAN Infrastructure	MEDIUM-HIGH
Network Security	MODERATE	Internet Traffic Analysis	LOW
Host Security	HIGH	Documentation	LOW
Content Inspection	ELEVATED	Policies	ELEVATED

RATING	DEFINED AS
HIGH	Serious vulnerabilities that have been exploited or are highly likely to be exploited in addition to significant deficiencies in design, implementation or management.
MEDIUM-HIGH	Vulnerabilities identified with moderate likelihood of exploitation and at least one significant deficiency in design, implementation or management.
MODERATE	Vulnerabilities discovered with low likelihood of exploitation coupled with minor deficiencies in design, implementation or management.
ELEVATED	No vulnerabilities discovered but minor deficiencies in design, implementation or management were discovered. All critical patches and service packs have been applied.
LOW	No vulnerabilities or deficiencies in design, implementation or management. All patches and service packs have been applied.

Prior to 2010 we found reliability issues with Windows Software Update Service (WSUS) which resulted in failed attempts to automate deployment for patches and updates to Microsoft operating systems, both on the desktop and server side. During the third quarter of 2010 we finalized an evaluation and purchase a new Dell Kace systems management appliance which was deployed in 2011.

The Kace appliance is capable of managing deployment of Microsoft patches and updates with more ease and efficiency over the WSUS solution. We intend to use the strengths of the Dell Kace appliance to remediate the issues around Host Security. The Kace appliance also allows users to perform OVAL-based vulnerability scanning of all managed Windows systems, which is an information community standard endorsed by US Computer Emergency Readiness Team (US Cert) and the Department of Homeland Security.

Throughout 2011 and continuing into 2012, the following security concern remediation activities are in progress:

1. We are continuing with Nessus scans and will continue with performing server and workstation operating system hardening and verifying that settings have been applied.
2. Utilize an automated patch management system to keep Microsoft operating systems up to date. This effort will be managed by the Dell Kace systems management appliance.
3. Implement VLANs and access control lists to segregate the business network and place the servers in a separate address space. We are in progress and will continue working on having servers segregated as recommended by the security assessment and desktops segregation will be targeted when the edge switches are replaced over the next few years.
4. Work with SAP to identify options, if any, to isolate web services modules from the database.

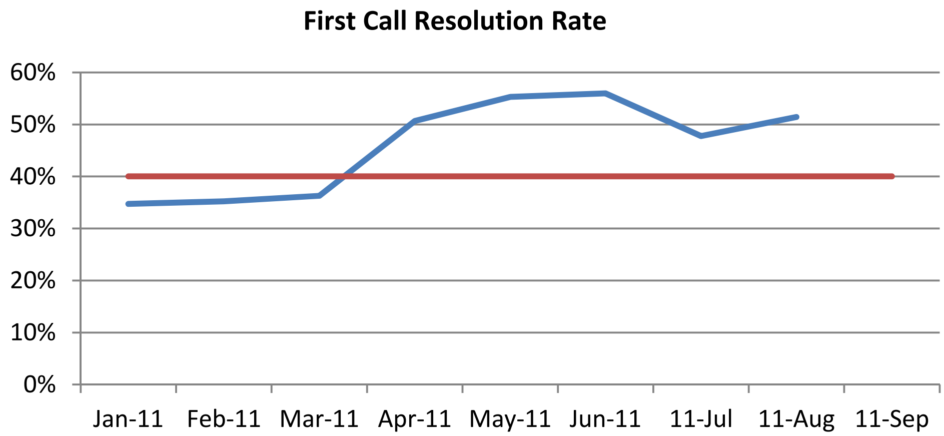
At the application layer we have identified that we are over-exposed with regards to level of user authorizations in the production SAP environment. Since go-live in 2009 our focus has been on ensuring users have authorizations necessary to carry out their day to day operations and any data cleanup work towards improving data quality and system stabilization. Over the course of the past two years however, many users have accumulated authorizations that are no longer necessary and could be considered as a risk area. Over the course of 2012 we will need to take a step back and re-evaluate how user authorizations are managed given the current system state and gained experience with an internal audit of the role/privilege assignments to ensure appropriate segregation of duties.

2.3. Systems Support

Currently the London Hydro IT service desk includes two part time Level 1 personnel and three Level 2 LAN Administrators. In January of 2011, the team went into production with a new service desk offering, the Dell Kbox. The new tool offered a number of advantages over the Service Desk included in the SAP Solution Manager.

Over the period since SAP go-live, it had become clear that while the SAP Solution Manager Help Desk was useful for tracking and addressing SAP tickets, it was not accessible or easy to use by all employees. Management and reporting of outstanding support tickets was a cumbersome process and search facilities were significantly lacking. In order to provide adequate support to the business, alternate service desk systems needed to be considered along with self-service options allowing end users to submit and obtain status updates.

The Kbox has enabled a number of improvements that are appreciated by all employees. The web based employee portal allows employees to easily log and track their tickets. Tickets are automatically routed to the appropriate support teams. The portal allows employees to download and install authorized and licensed software without having to have administrator rights on their machines. A Knowledge Base is provided to let employees search and get answers to frequently asked questions or work around for known issues and problems.



The IT service support structure currently has no formalized service level agreements with the business or well defined performance targets or operational goals. This is primarily a result of being in 'fire-fighting' mode since SAP go-live, acting in very much a reactive manner to deal with a volume of problems that exceeds the capacity of the available resources. As the SAP system begins to stabilize and plans for implementation of new systems are being created, it is becoming more important to establish process and structure around the support aspects of not only the SAP environment, but all business applications. This is something that extends outside of support staff and must become a consideration in all projects since they will eventually transition to support.

Over 2011, progress has been made on these issues. An initial IT service catalog and standard costing model has been developed. This service catalog will be developed to include the Service Level Agreements for the defined services in 2012.

2.4. IT/PMO Capabilities

Strengths	Weaknesses	Opportunities	Threats
Systems Knowledge	SAP Skills	Collaboration	Retention
Business Knowledge	Work Processes	Customer Engagement	Scale
Creativity	User Expectations	Adoption & QA	External Reliance
IT Operations	Change Management	AMI & Smart Metering	Regulatory Changes

2.4.1. Strengths

Knowledge in both systems (outside of the scope of SAP) and business key areas is an important strength that the IT services team has; however, this knowledge is often found in silos. We have been working on cross-training and collaboration to expand the base skill sets of staff in 2011 but additional effort needs to be put in to distribute knowledge further throughout the team on an ongoing basis to build on these existing strengths.

Existing resources are also able to find creative solutions to problems, which is important for an organization of London Hydro's size. Creativity in solution development should be encouraged, but needs to be carefully balanced with practicality and lifecycle support requirements to ensure sustainability.

2.4.2. Weaknesses

The key area of weakness in the current environment relates to SAP skills in both functional and technical areas. Very few internal resources have had any formal SAP training and most have obtained their existing knowledge only through hands-on use of the system. This weakness creates a dependence on external consultants even for relatively small system changes and hinders London Hydro's ability to evaluate the quality of work completed by contractors. In 2011 we have started to focus on staff training to build our internal capabilities and there will need to be an ongoing commitment to this to ensure we maintain currency in the core technologies we use.

Focus also needs to be put on work processes and change management as the IT services organization is lacking formalized processes and consistency in solution delivery. Defining standards for processes, especially in relation to solution delivery and management is necessary to improve efficiency in the project lifecycle and achieve better cost control, particularly with regards to external consulting services. Some progress has been made in this area during 2011 but there remains some inconsistency between projects and needs continued focus through 2012 and 2013.

The IT services team also needs to improve user focus of development and support activities to consider solutions from the end user perspective. As with most IT organizations, there is a tendency to view solutions primarily from a technical and ease of implementation perspective, with much reduced emphasis on end user experience, which can lead to ineffective solutions for the business. Overcoming this weakness will lead to more effective solutions and a greater level of business acceptance.

2.4.3. Opportunities

The Ontario electricity market and the utility industry in general is at a stage where there are many opportunities being presented. The Smart Metering initiatives and the systems required to support the surrounding processes have provided London Hydro with the opportunity in 2011 to collaborate with other utilities and vendors, for example, through the SAP lighthouse council, as well as direct collaboration with other local LDCs in Ontario. To this end we have presented at SAP Utilities conferences in

Germany and the USA and also at the Itron user's conference in the USA sharing our experiences and insight with vendors and other utilities. These collaborations allow us to influence future development of the software systems we use and explore the potential for cost reduction through knowledge sharing.

These efforts can help to further London Hydro's technology adoption goals and position the organization as a market leader, which would provide greater ability to influence vendor system development roadmaps and participation in early access releases to help improve quality assurance of London Hydro's production systems. As an example, in 2011 we were able to participate in the ramp up program for SAP Enhancement Pack 5 which has allowed us to test and deploy capabilities much earlier than would otherwise have been possible.

Customer engagement is a major opportunity for London Hydro as a whole. With the introduction of smart meters and time of use billing, along with conservation programs necessary to meet the organization's CDM targets, systems to empower customers in reducing energy usage or shifting to cheaper times in the day will provide a direct value impact to the customer. We have started to develop new web presentment capabilities as a first step in this area but we must continue to investigate integration of emerging and mobile technologies, including iOS, Blackberry and Android smart phone applications, social network integration, etc. over the next few years.

2.4.4. Threats

Staff retention and reliance on external consultants are key threats that relate to resourcing. We need to consider how we can assure long term retention of employees while still ensuring formal training and employee development to meet our needs. The resourcing model has improved in 2011 to reduce reliance on external consulting resources for day to day operations; however, there are still several key consultants critical to our operations. Over the longer term, reliance on external consultants for regular operations needs to be minimized to control both cost and risk.

Scale is also a concern for London Hydro – the organization and data processing requirements are such that larger scale solutions are sometimes required, yet the high entry cost of these solutions can be challenging. We aim to offset this with the agility afforded by the size of our organization, to deliver more efficiently than many organizations are able to.

2.5. Vendor Management & Partnerships

Early in 2011, we issued an RFP for selection of a set of preferred vendors with which London Hydro would work with over the next few years. The objective of this exercise was to ensure that London Hydro received competitive bids on work items and staff augmentation, but to reduce the overhead of RFP processes. Through this process five vendors were selected as preferred vendors through to the end of 2013:

- CapGemini [System Integrator]

- InfoSys [System Integrator]
- Tata Consultancy Services (TCS) [System Integrator]
- Procom [Staff Augmentation]
- RayTech [Staff Augmentation]

As we approach the first year anniversary of our preferred vendor agreement, we will be evaluating the performance of each vendor using a standard score card, incorporating

One of the objectives in London Hydro's SAP IS-U implementation was technology modernization at an affordable investment. Since the costs associated with implementation of an SAP system were substantial, London Hydro's vision was to lower total cost of ownership using a shared solution approach with other utilities. Unfortunately though, due to various reasons the initial drive to implement this vision could not be achieved. The concept resurfaced in 2010 and early 2011 in the concept of 'Utility in a Box' solution working with a system integration vendor and utilizing London Hydro's existing developments as a base template; however this did not result in any real opportunities. Recently we have started to explore the idea of a shared services model, working directly with other utilities in Southwest Ontario including Hydro One, EnWin and Kitchener Utilities. These discussions are at a very early conceptual stage but could provide a good opportunity to realize our earlier vision of a shared solution approach to TCO reduction.

Section 3. Business Objectives

3.1. Key Focus Areas

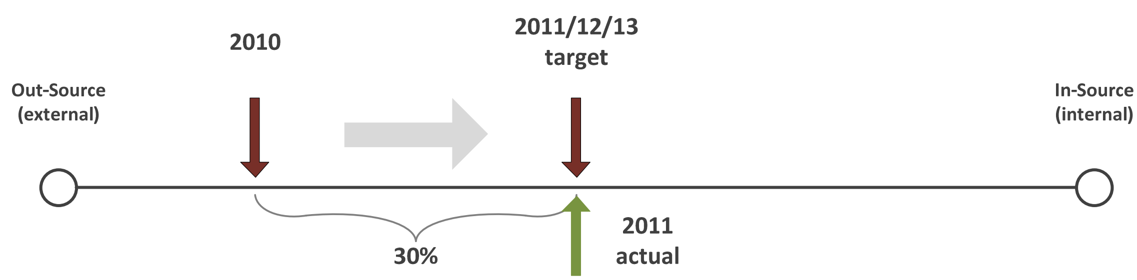
Three key areas have been defined for the Project Management Office and IT service departments to focus on in future initiatives:

- 3 Year Program & Technology Outlook
- Integrated Resource Planning
- Quality and Cost Control

3.2. IT Services Goals

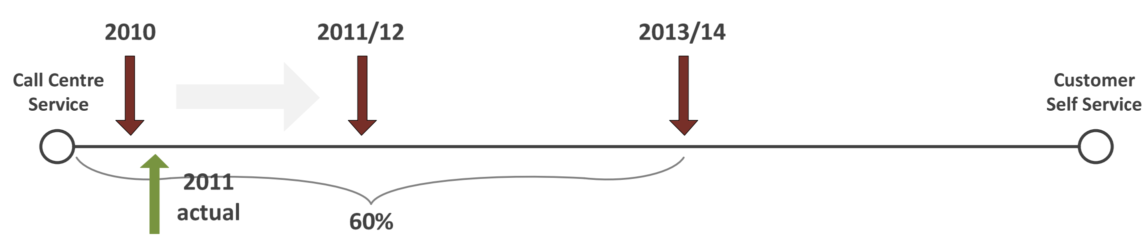
In support of the London Hydro corporate objectives, IT Services has established a number of internal goals to strive towards in the period leading to 2014:

Resourcing Model – Cost Control & Sustainability



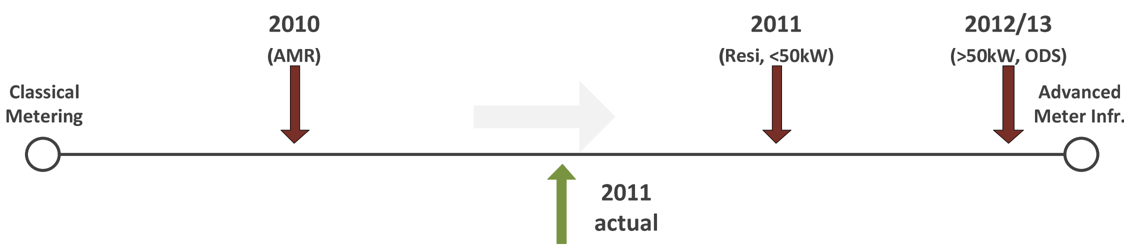
Throughout 2009 and 2010, London Hydro's resource model for IT Application Management Services (AMS) and development was heavily weighted towards utilization of external consultants, primarily a result of having little internal SAP skills. In 2011 we have focused on reducing our external resource dependency through building up internal strengths and new hires to complement our existing knowledge base. While we have achieved a more balanced resourcing model, it will be necessary to continue building up internal SAP strengths and "re-tooling" staff to ensure that internal resourcing is sufficient for management of all critical application components.

Customer Engagement and Self-service – Operational Efficiency & Enhanced Service



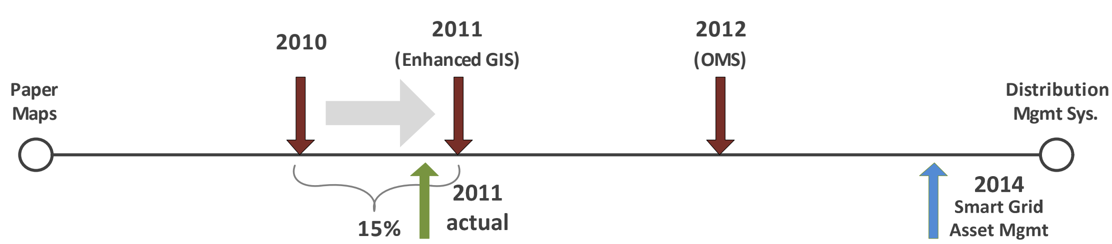
Customers' primary method of communication with London Hydro today is via phone to the call centre. In 2010, customer self-service functionality connected to SAP was introduced with the Utility Customer e-Services (UCES) application which has continued to receive some minor enhancements in 2011. Growth in customer adoption of self-service functionality has continued, but not in the substantial volume that we had hoped for. Implementation of new capabilities in late 2011/early 2012 including Time of Use/smart meter data presentment and a property management portal is expected to provide greater incentive for customers to utilize the self-service capabilities, which in turn is expected to drive the adoption. The ultimate aim of these developments is to facilitate a major shift in customer behavior to empowered self-service options, reducing call centre overheads, improving service levels and supporting 24 hour accessibility of customer services. This will only be achieved if we can offer capabilities that utilize the medium of the web to exceed the information a customer can obtain via their bill and a phone call.

Advanced Metering Infrastructure – Regulatory Objective



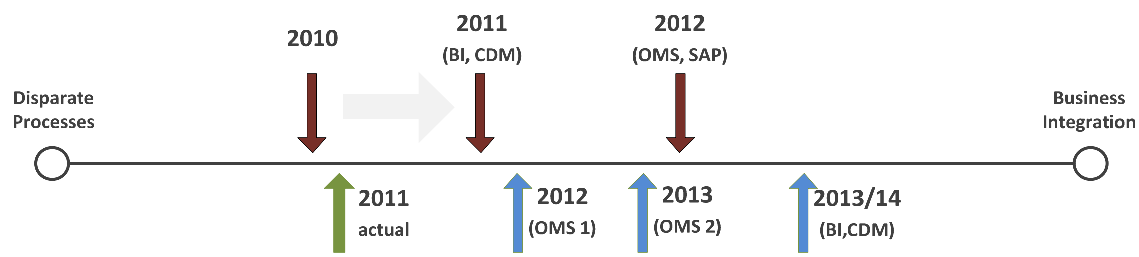
London Hydro has already made progress on the road to full AMI utilization with the implementation and transition to AMR in 2010, extracting early value from the deployed AMI infrastructure. In 2011 we expected to have all RPP smart metered customers moved over to Time of Use billing; however, due to issues with AMI network performance, an extension to the mandatory ToU deadline was granted to London Hydro until March 31st 2012. Despite setbacks outside of our control, over 135,000 meters are actively synchronized and transferring data to the provincial MDM/R. By the end of 2011 we will begin the conversion of customer to Time of Use rates, completing in Q1 2012. With the deployment of an Itron Enterprise Edition Operational Data Store (ODS) in Q4 2011, we will remain on track to realize the 2012/2013 target for simplification of systems and processes through integration of capabilities for larger Commercial and Industrial customers (>50kW).

Distribution Management – Operational Efficiency & Reliability



GIS enhancements planned for 2011 to strengthen the spatial connectivity model of assets and improve utilization of the GIS have largely been completed, though some items are expected to carry over into Q1 2012. Requirements gathering exercises for Outage Management System (OMS) implementation have been conducted in 2011 with the implementation of this system to begin in 2012. Beyond the OMS system itself, integration with GIS and SCADA systems (and potentially SAP and ODS systems) will yet further advance capabilities in this area. Moving further into the future we will investigate the potential for a smart grid asset management to enable intelligent grid monitoring and grid data integration/analysis.

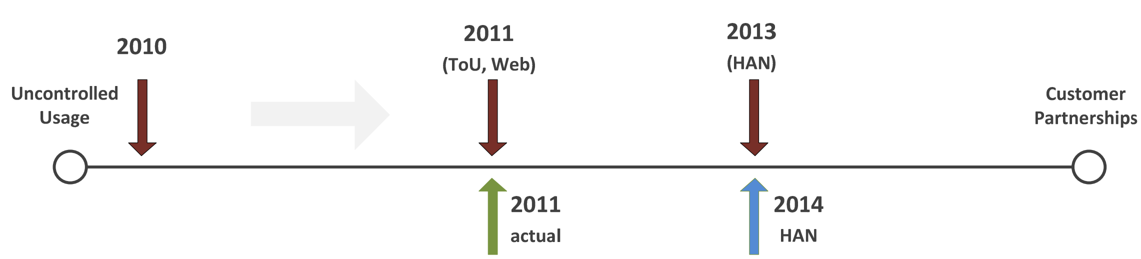
Business Integration



Many processes within London Hydro have some form of integration within the existing SAP IS-U system; however, there are also many disparate processes and weak connectivity. Integration of BI and CDM functionality had been planned for 2011; however, with unclear business need in these areas we have elected to postpone any efforts until 2013/2014. The scope of functionality for an Outage Management System (OMS) has expanded from initial assumptions as requirements gathering activities have taken place in 2011 – this project will be a major focus for both 2012 and 2013 with implementation of the OMS application foundation and subsequent integration with existing systems including GIS, IVR and SAP.

Over the course of 2012/13 in addition to the major projects being undertaken we shall also undertake several smaller system rationalization activities, particularly in the area of asset management to increase utilization of the core SAP ERP components as a stepping stone towards an eventual complete ERP implementation, which will result in more integrated, seamless and more efficient business processes.

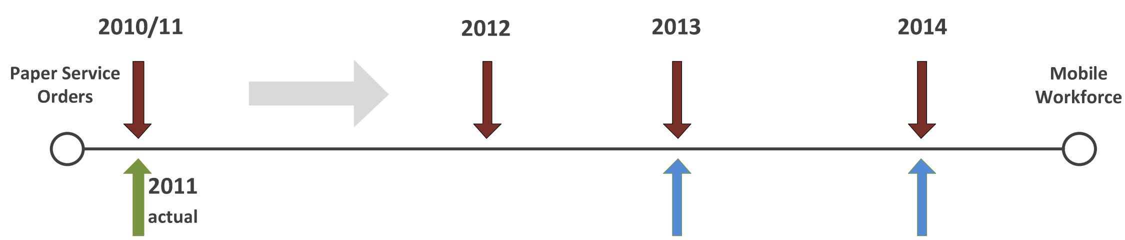
Customer/Conservation Partnerships



While current conservation programs exist and have even exceeded expectations, it is expected that the nature of conservation and demand management will shift over the coming years towards customer partnerships whereby customers have the information and ability to make active decisions on energy usage. This will initially be driven by the introduction of time of use billing and will be facilitated through implementation of a web presentment solution to provide customers with information regarding their energy usage. As technologies and customer engagement develops, opportunities to interact more directly will be pursued, utilizing home area network devices and connectivity for dynamic interaction with individual consumers.

Time of use billing roll-out, as mentioned elsewhere, has been delayed until Q1 2012 though the development and capabilities required have been completed in 2011. Home Area Network opportunities remain a longer term goal, though technology concerns, such as AMI network bandwidth constraints and availability of hardware are likely to push any opportunities in this area to 2014 or beyond.

Field Service Work – Productivity Gains



Paper service orders capture almost all of London Hydro's field service work currently. Our goal had been to initiate implementation of mobile workforce tools in 2012 though it has become clear during 2011 that the implementation of the Outage Management System and in particular the application integration technologies we utilize to provide connectivity between our enterprise systems will play an important part in enabling field service work improvements. Due to this dependency, we have realigned goals in this area to begin during 2013 with further enhancement through 2014. With increasing emphasis on larger volumes of data and processing timelines, real time or near real time field work updates will become important. Continuous advances in smart phone and tablet technologies should allow this shift at lower costs than possible today by utilizing commodity hardware platforms.

Section 4. Direction and Strategy

4.1. Key Initiatives

Focus Area	Initiative	Strategies
3 Year Program & Technology Outlook	Strategy & Architecture	Technology Outlook and Roadmaps Systems Integration Approach Architectural Evolution
	Enterprise Systems	System Consolidation Removal of Cottage Industry Application Rationalization/Optimization Enterprise Resource Planning Utility Operations Reporting & Business Intelligence
	New Business Capabilities	AMI & Smart Metering Conservation and Demand Management Customer Engagement Emerging Technologies Mobile Workforce Automation
Integrated Resource Planning	Resourcing Structure	Organization Structure Employee Development External Resourcing
Quality & Cost Control	IT Business Improvements	Project Management Processes Documentation Standards Quality Assurance Cloud Computing/SaaS Shared Service Model Communication and Collaboration Tools Quality Control

4.2. Strategy and Architecture

4.2.1. Technology Outlook & Roadmaps

We will endeavor to develop maintain an follow a series of technology roadmaps and strategies in key business and systems areas, defining desired 3 year program technology end states to support London Hydro's business needs and processes to develop from current state through to the end state in a clear logical manner. Taking a more strategic long-term program approach will result in reduced lifecycle cost through avoidance of rework during progression towards the end state and also with regards to influence of architectural decisions made within individual projects.

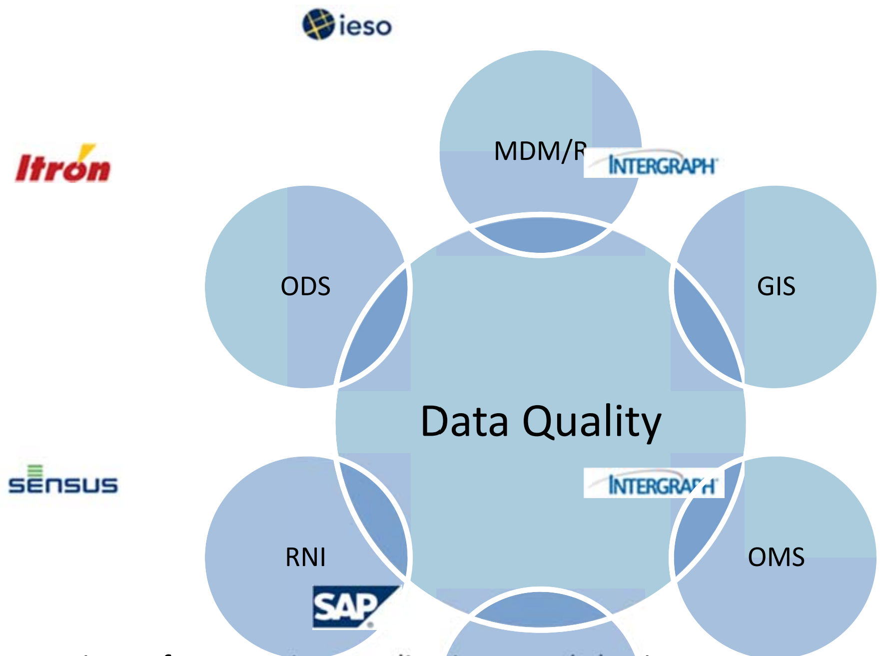
Due to the rapid pace of development in the IT space, we intend to re-evaluate our outlook and roadmaps on an as-needed basis to determine progress made towards the defined end state and ensure continued alignment with our own goals and objectives, those of the organization as a whole and also with key vendor product roadmaps.

This technology outlook has been started in 2011 with focus around the SAP IS-U system and in particular SAP's MDUS architecture for integration of AMI systems. An alignment of future developments with SAP's roadmap and participation in working groups to evaluate and provide feedback on proposed SAP enhancements allows us to appropriately plan functionality implementation and minimize custom development. In 2012 the focus will be extended across the entire application landscape and in particular to enterprise application integration technology.

4.2.2. Systems Integration Approach

Traditionally, London Hydro has had a systems level approach to implementation of IT solutions, focusing in detail on individual systems and their internal operations, but giving little consideration to the overall IT landscape. More effective use of existing IT infrastructure and system capabilities as well as reducing lifecycle costs in future projects can be realized by looking at the 'big picture'. Within each development project it will be necessary to consider the impact of new systems across the application space and justify any increase in landscape complexity since any point of connectivity between systems is also a potential point of failure.

Virtually all connectivity between systems in London Hydro's current application landscape is implemented as point to point connections - interface connectivity between two specific systems. Over the coming years as part of our technology outlook and roadmap efforts we will evaluate implementation of alternate strategies, including a service bus oriented approach and potential utilization of the 'multispeak' or IEC 61968 CIM standards to add flexibility to the architecture and maintain more loosely coupled system integration. The initial intention was to utilize SAP's Process Integration (PI) system, which is part of the SAP environment, as a hub for application integration; however, with resourcing, technical and third party support concerns that we have experienced in this area, we are also exploring other middleware alternatives.



Through the integration of enterprise applications and business processes we ultimately aim to ensure the quality and integrity of data, providing a single source of truth for London Hydro's information assets and facilitate implementation of future capabilities.

4.2.2. Architectural Evolution

With long-term integration strategies and technology roadmaps defined, it is possible to plan more effective approaches to realization of desired architecture end states. We will endeavor to develop a more iterative and evolutionary approach to architectural changes. This will be achieved where possible by implementing smaller more manageable changes over longer periods of time rather larger big-bang type changes that can be disruptive to operational processes.

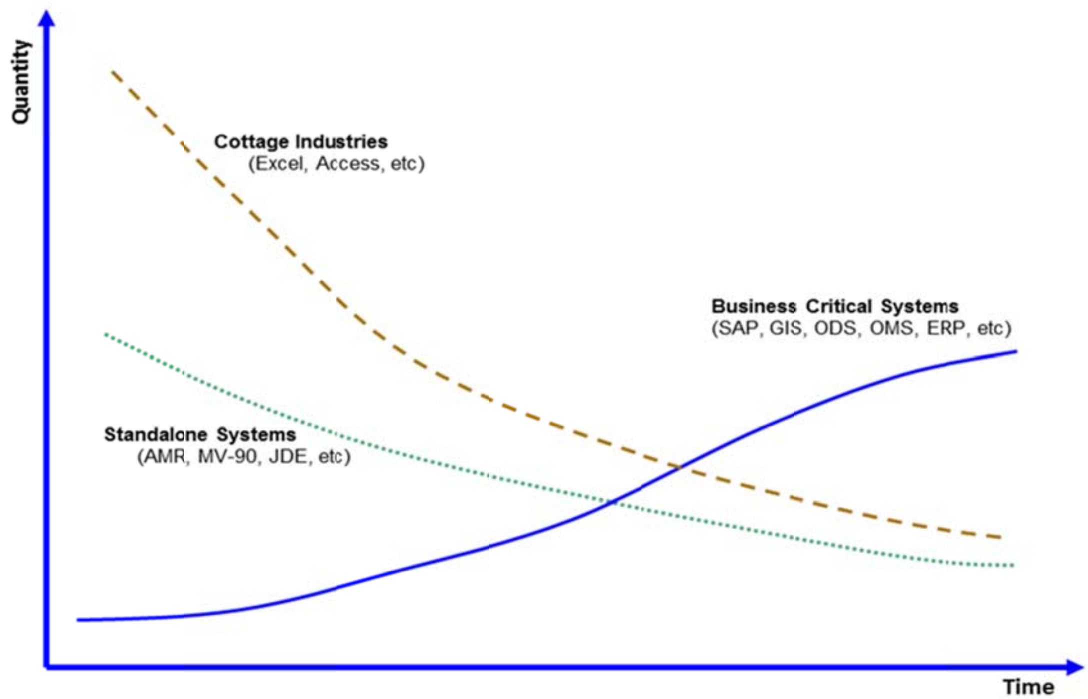
Implementation of ERP capabilities is one of the key areas that can benefit from this approach by implementing process changes and core ERP component capabilities in small projects rather than through an all-out large, resource intensive implementation.

4.3. Enterprise Systems

4.3.1. System Consolidation

London Hydro's application landscape continues to grow as new applications are introduced in support of business and regulatory initiatives. As this growth occurs, overheads of maintenance and support increase and more diversified skill sets are required. To ensure that business applications and IT infrastructure can be effectively supported, one of our general principles is to continuously evaluate our landscapes for opportunities to simplify and consolidate processes.

As illustrated in the graph below, our intent is to reduce the volume of secondary and 'cottage industry' systems by incorporating functionality and processes into our larger enterprise systems. While this is a general principle that we apply, it is not a global target – each system must be considered on a case by case basis since system consolidation is a tradeoff between complexity in the application landscape and complexity within an enterprise system.



The process of evaluation for system consolidation is an ongoing one taking small steps towards a larger goal. In 2012 this will begin with the transitioning of "Kovan's Application" to integrated SAP functionality. This application, which is an outdated and unmaintained tool built by a summer student to assist the Electric Meter department with asset management processes will be replaced by more advanced capabilities available in our existing SAP system. Similar efforts will be made in other areas of the organization over the next few years, not only towards the goal of removing 'cottage industry' systems, but also to enable our enterprise systems to be leveraged for future process enhancements.

4.3.2. Removal of Cottage Industry

As mentioned elsewhere in this document, cottage industry type systems, which often take the form of Microsoft Access databases or sophisticated Excel spreadsheets usually arise within business departments to satisfy an IT need that is not being met by existing systems supported by the corporate IT organization. These systems pose a risk for IT and London Hydro as a whole for several reasons:

- Data sources for these systems may not be validated or correctly understood, resulting in business decisions or actions taken on incorrect information.

- Systems are not considered in impact analysis for changes to enterprise and specialized systems, since they are not well defined.
- Systems are not tested for interoperability with new software versions, such as Microsoft Office or Windows, or conflicts with other business applications.
- Systems may be business critical, but are not included in disaster recovery planning or appropriate data backup.

Removing these systems is one of highest priority items for data integrity management and system consolidation, but needs to be approached carefully and methodically to prevent business disruption. The purpose and use of these systems needs to be well understood so that processes and requirements can be incorporated into the supported enterprise system.

The goal for these types of system is not only to remove them from the IT landscape, but also to prevent new ones from being created. This is the more challenging aspect of managing cottage industry systems since it requires greater depth of understanding in business processes and anticipation of how user will utilize solutions to identify potential gap areas.

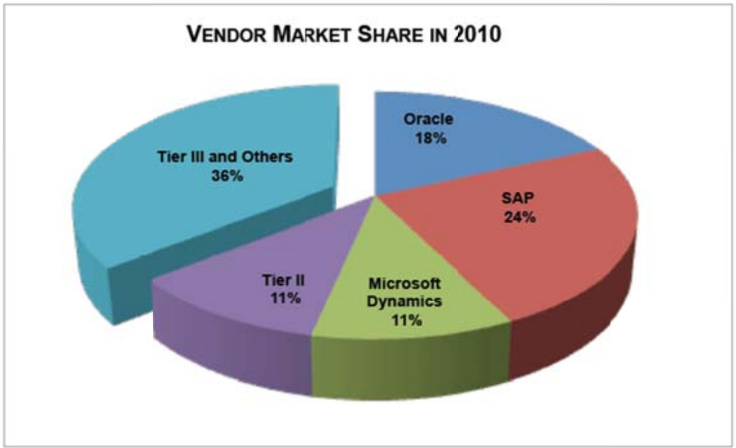
4.3.3. Application Rationalization/Optimization

In support of our objectives to consolidate our system landscape, remove 'cottage industry' systems and deliver value to the business, in 2012 we will initiate an ongoing program of application rationalization and optimization. The purpose of this program is to review current business and technical processes and implement improvements leveraging our *existing* applications and ensuring that we continue to extract the best value from the technology investments we have already made.

There are many possibilities and opportunities of varying scale to be evaluated, from small user interface improvements to streamline data entry and validation, through to larger scale overhaul of customer service functionality using new capabilities delivered by SAP in the recently deployed Enhancement Pack 5. The key focus of this development program will be working with the business to identify the best enhancement opportunities providing relatively short term return on investment.

4.3.4. Enterprise Resource Planning

With a goal of simplifying the IT application landscape and bringing in further process integration to help optimize business operations, we are looking towards SAP's Enterprise Resource Planning (ERP) solution as a platform for enterprise system consolidation and development. SAP is currently the market leader in the ERP space, capturing 24% of the market and utilizing their ERP solution would allow us to leverage the significant investments already made in the SAP environment at London Hydro.



Our intention would be to utilize the capabilities of the core SAP ERP modules to facilitate system rationalization, simplifying our application landscape and extending the solution into other areas of the organization while building towards the full ERP integration capabilities. Following this process will eventually result in the consolidation of the JDEdwards enterprise system into the equivalent SAP modules:

JD Edwards ERP Module	SAP ERP Module
General Ledger	FI-General Ledger (FI-GL), FI-Controlling (FI-CO)
Procurement & Material Management	Materials Management (MM)
Fixed Asset & Work Order	FI-Asset Accounting (FI-AA), Project Systems (PS) Plant Maintenance (PM)
Accounts Payable	FI-Accounts Receivable (FI-AR), FI-Accounts Payable (FI-AP)
Payroll & Attendance	HR & Payroll

Once the core ERP components are in place and operational, processes within other organization areas can then be integrated within the SAP modules already activated, or additional SAP modules can be more easily activated – as the system scope increases, the overhead of adding functionality tends to reduce as the principles of the system become better understood by the business and less mock configuration must be completed to satisfy integration dependencies.

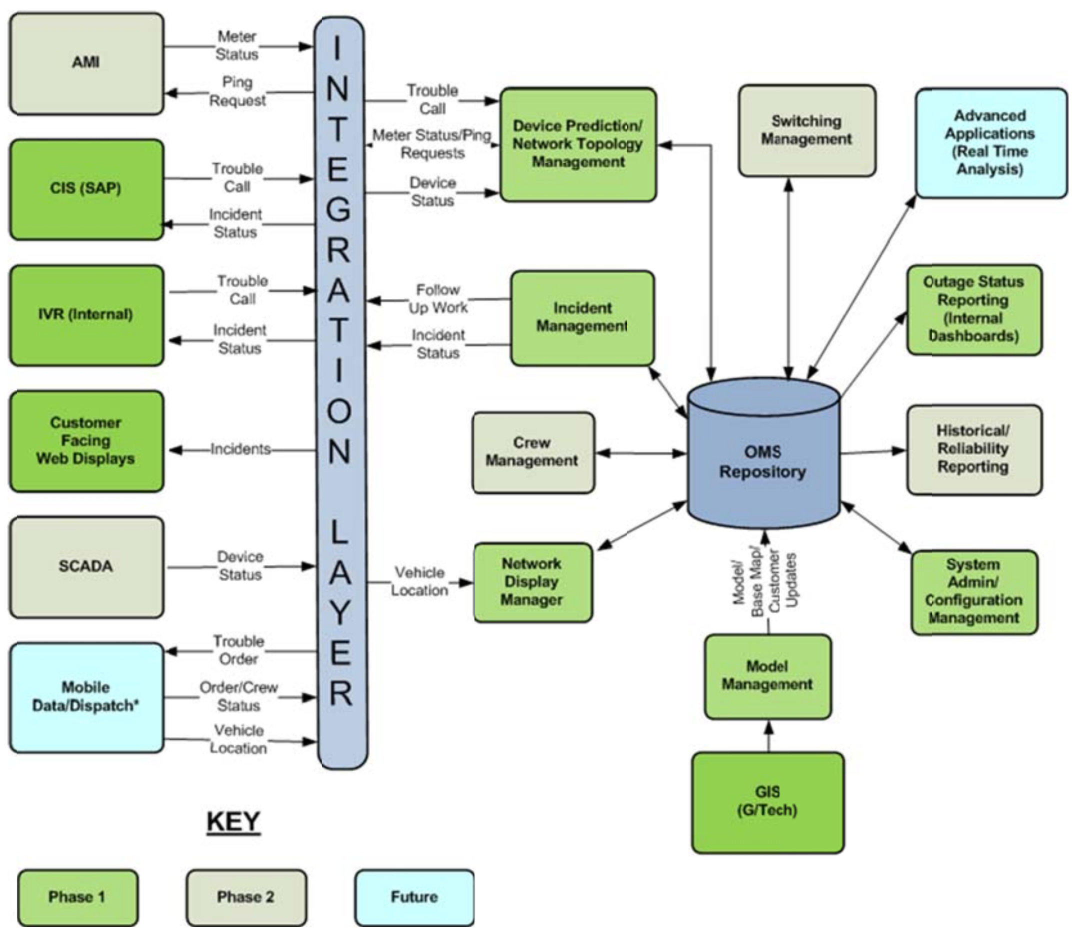
We believe that through an SAP ERP approach, operational synergies can be achieved between ERP and IS-U (CIS) components within our SAP environment, facilitating exploitation of long term opportunities to build common, integrated business practices and processes, which would not be achievable in a more disparate system environment. Realization of these goals will take a number of years with smaller efforts starting in 2012 and through 2013 as part of our application rationalization and optimization program, looking towards the initiation of an integrated ERP project in the 2014 timeframe. It will be important in the interim to establish a clear business case and objectives to determine the extent of this project's scope and value.

4.3.5. Utility Operations

In previous years our focus in the utility operations space has been the implementation and improvement of the Intergraph GIS, building a system of record for location and connectivity of distribution assets. As the current GIS enhancements project wraps up in 2012, focus will shift towards the implementation and integration of an Outage Management System (OMS), utilizing the GIS connectivity and SAP customer data to provide new capabilities for both internal control room operations and extending out directly to our customers.

Part of the integration efforts for these systems will be to establish stronger enterprise data models, providing better alignment of logical entities between various enterprise systems. This application integration will also serve as a model for further future integration between our enterprise systems.

The below diagram and table illustrate our initial concept for integration of OMS capabilities over the next several years and the value proposition of these capabilities:



	Area	Value	Opportunity
1	Customer Communication	●	▪ Proactive communication ▪ Automatic outbound
2	System Reliability	◔	▪ Improved response/restoration time
3	Control Room	◔ ◑ ● ◔	▪ Realtime outage/extent of outage information ▪ Handles multiple outages ▪ Improved safety – automatic switching orders ▪ Less stress on staff eg answering calls
4	GIS Tech	◔	▪ Reduced effort, "Oneview" , no paper maps
5	Engineering & Planning	◔	▪ Access to Real Time Configuration

Over the longer term, moving into 2014 and beyond, our goals are to further the development and integration of GIS, OMS and our other enterprise systems, to support much more complex and higher value functions that drive efficiencies. Such functions could include commitment of current available stock for work orders, automation of ordering of new stock (GIS with Materials Management, Design) and queuing/remote dispatch of service orders to available and appropriate crews (GIS and OMS with HR, SAP, Workforce Management, Route Planning).

4.3.6. Reporting & Business Intelligence

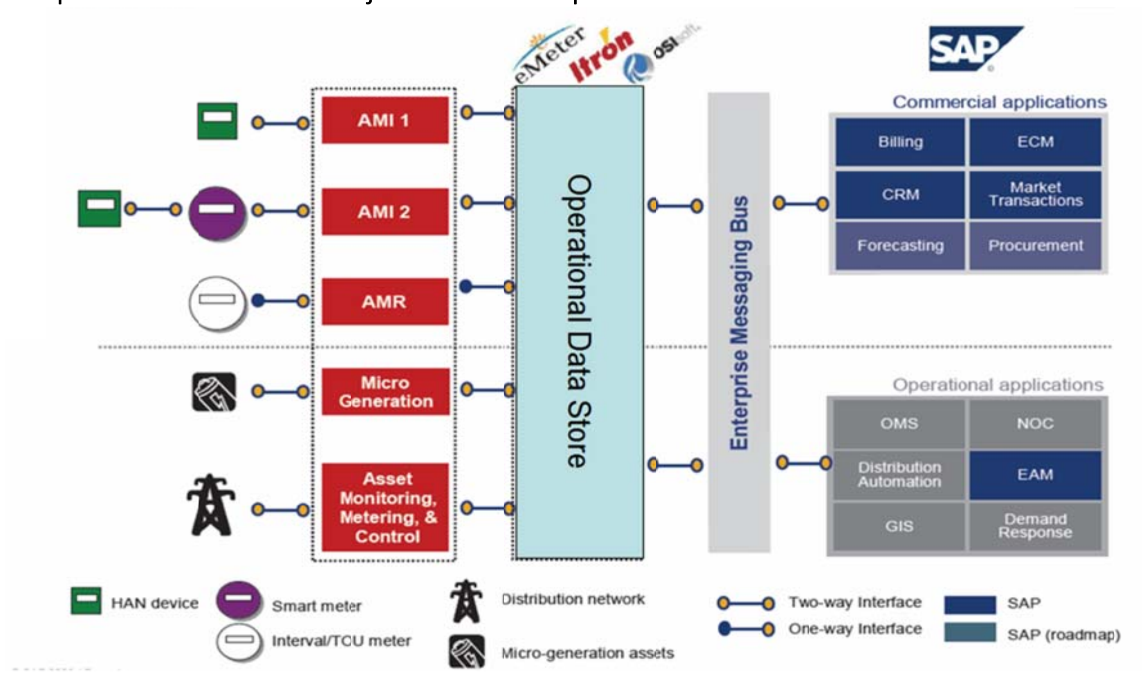
Reporting has been an ongoing concern surrounding implementation of new systems in the application landscape. As new systems are introduced, mechanisms for reporting are introduced, invariably with differences from reporting used for other systems. Increasing use of enterprise systems results in a substantial growth in reporting needs and the technology used to satisfy these needs must be controlled to ensure consistency and integrity of enterprise data.

In 2011 we have started work on a reporting strategy to help define the approach and tools for building and maintaining reports across the organization, covering both transactional and business intelligence type reporting including enterprise data warehousing. This will be applied initially to transactional reporting development in 2012, which currently makes up the bulk of London Hydro's reporting requirements and later to business intelligence reporting further into 2013 as we establish business drivers and develop functionality in that area. Although we are not initiating an actual BI implementation project until 2013, components of the SAP Business Objects suite have already been deployed into our application landscape to facilitate consolidation of data extraction and transformation processes for both reporting and application integration and we intend to expand our use of these tools over the next few years to better manage integration processes.

4.4. New Business Capabilities

4.4.1. AMI & Smart Metering

In the process of evaluating strategies for integration and management of AMI and Smart Meter systems into London Hydro's technology landscape, we engaged SAP to look at our systems, data storage and processing requirements in relation to interoperability with the existing SAP CIS solution. In this evaluation, SAP advocated adoption of their Meter Data Unification & Synchronization (MDUS) standard for AMI back office integration and deployment of an MDUS compliant Operational Data Store (ODS). This standard provides a pre-built service based interface between SAP Utilities components and several major ODS vendor products.



Utilization of the MDUS standard and a compliant ODS system aligns London Hydro's enterprise systems with SAP's long term Utilities development roadmap, enabling new functionalities within and between SAP and ODS systems as SAP and ODS partners deliver enhancement packages in 18 to 24 month cycles. Throughout 2011 we have been active participants in SAP's 'AMI Lighthouse Council' (now known as the 'Smart Grid Innovation Council'), advising the SAP utilities development team of utility needs for inclusion in future enhancement packs. Through this collaboration and with the agility of our internal team we were able to participate in the ramp up program for Enhancement Pack 5 and were the second utility in North America to deploy these new components. With the go-live of our initial ODS implementation at the end of 2011 we will also be one of the first utilities to deploy the SAP AMI/MDUS infrastructure, positioning ourselves as technology leaders and progressive participants in this area.

The initial ODS deployment will primarily facilitate smoother operational processes interacting with the provincial MDM/R and provide the fundamental system functionality to store, manage and utilize hourly smart meter data. This system is also a strategic investment providing enabling technology that will allow future development of more sophisticated functionality within our enterprise systems in two major areas:

1. Meter Data Management and Billing
   Initially we will pursue enabling functionality to support Commercial and Industrial (C&I) services, removing the need for the separate Itron MV-90 interval meter interrogation and data management system, which will lead to a unified system for management of all types of meter data. The ODS system will also facilitate additional automation to wholesale settlement processes and calculation of complex bill determinants for distributed and micro generation services to be passed seamlessly on to the SAP billing engine.

2. Engineering & Operations
   The ODS system will enable access not only to significantly more detailed usage profiles than previously available, but will also provide even data from meters indicating events such as voltage tolerances, etc. In conjunction with eventual GIS integration users will have the ability to determine detailed load profiles at any point on the distribution grid to aid in distribution planning.

We will begin to leverage this investment further in 2012 beginning with utilization of smart meter data to improve accuracy of customer usage in our CYME and GIS systems and evaluate the further possibilities through 2013 and beyond in alignment with our application rationalization/optimization and key projects.

4.4.2. Conservation & Demand Management

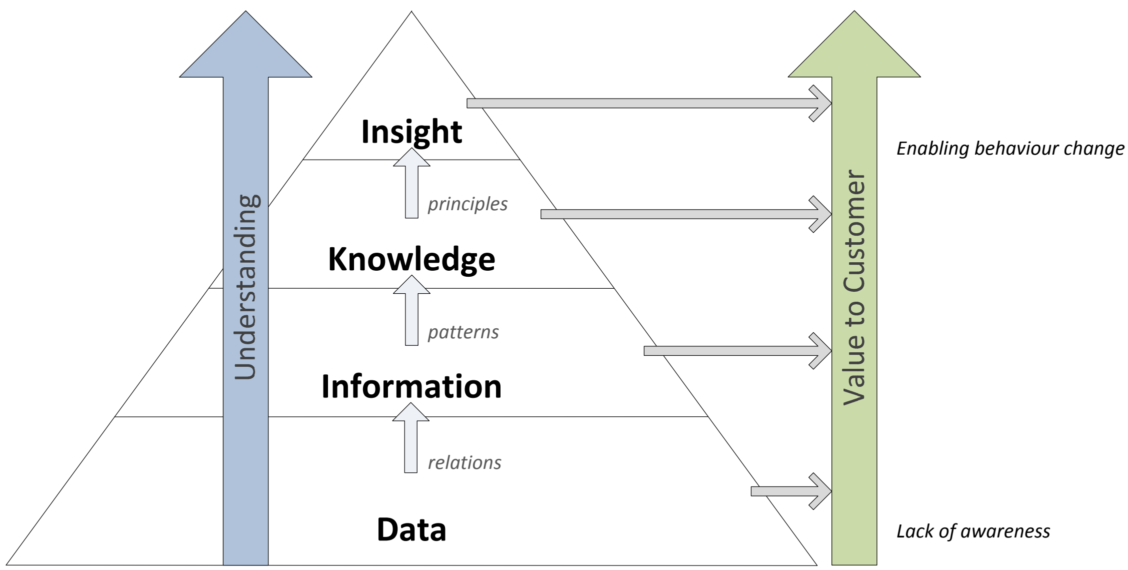
To date, involvement in conservation and demand management has been primarily focused on provision of customer data from our SAP system to support targeting of various programs. In conjunction with our reporting strategy and Business Intelligence our aim during the next few years will be to standardize reporting in this area and make reporting tools accessible directly to users in the CDM department, allowing greater self-sufficiency in operation and ensuring up to date customer information is always available.

Previously we have given consideration to implementation of CDM program management functions within our SAP landscape; however, currently we support the CDM department's use of the hosted salesforce.com CRM application, which provides sufficient capability to meet current needs and is accessible using standard connectors with our SAP Business Objects reporting/BI software suite. If usage and data volumes grow substantially in this area then it may necessary to consider bringing these functions into our SAP CRM system, though in the current situation and usage this would be overkill.

4.4.3. Customer Engagement

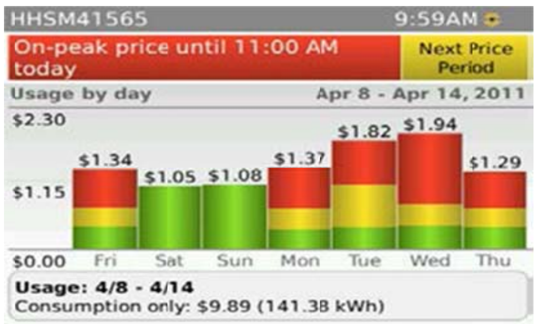
Customer engagement is one of the biggest opportunities that London Hydro can capitalize on over the next few years. The implementation of smart metering and time of use pricing will provide pricing incentive to understand more about their usage patterns and trigger questions of how to reduce costs. Leading utilities will take advantage of this increase in complexity to sell the benefits of customer self-service solutions that can show the customer how they can better manage energy usage.

The key focus for customer engagement should be the provision of information and knowledge to the customer regarding their energy usage. Basic customer self-service solutions provide data presentment, showing customers their hourly meter data and basic bill information. This is a necessary first step in building up infrastructure to support advanced self-service functions, but will never drive significant adoption or influence customer energy usage at any large volume since most consumers are simply not interested in spending time analyzing energy data.



Building on the availability of meter and billing data to inform and advise customers how their usage patterns and behaviors influence their electricity bill, or how their efficiency compares to like customers will build knowledge and insight which in turn will enable behavior change on a much larger scale.

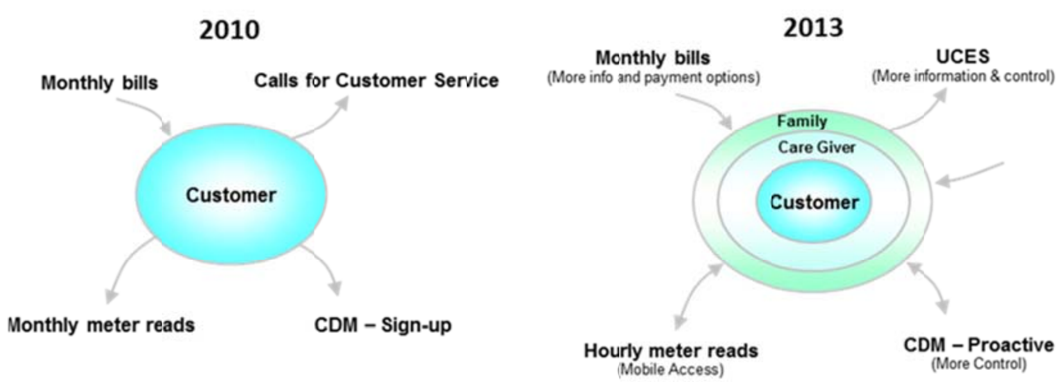
The direction we are pursuing to drive customer engagement is to offer new unique and innovative capabilities possible with media such as the world wide web and smartphones/tablet devices. To this end in 2011 we engaged Sonic Boom Creative Media to design and implement the first stage of a new web application, integrating time of use capabilities with our existing UCES self-service application and providing a new property management portal for London property owners. We will continue to expand these developments in 2012 replacing all of the existing functionality of SAP's UCES module with custom web self-service capabilities that will allow us to provide an improved user experience to our customers. These improvements in existing capabilities and user experience will provide a foundation for the next generation of self-service, customer engagement and mobile device capabilities to be deployed in 2013 and 2014.



Traditional Utility Web Approach

LH Refined User Experience

The next generation of functionality for our customer engagement platform will aim to support CDM program participation, micro generation and enhancements for support of traditional customer service functions, such move-in/move-out and property manager functions. Over the next several years we anticipate a shift in how we define customers, expanding our to engagement of family members and other authorized persons beyond the traditional customer, which may also prompt review of existing customer service processes.



4.4.4. Emerging Technologies

Social Networking applications, such as Facebook and Twitter have seen explosive growth since 2007. Current estimates put Facebook's user base over 760 million (with almost 17 million in Canada alone) and Twitter over 200 million users, with an equivalent number of 'tweets' being sent every day. The popularity of these services could provide a major channel for communications with consumers, but leveraging this requires a shift in mindset and commitment from traditional avenues of communication. In London Hydro's 2011 customer survey, participants were asked how likely they were to use social media to gather information on conservation, with the following results:

In our previous strategy document it was identified that while these services present excellent opportunities to engage customers and enhance corporate image, they present equal opportunity to tarnish the corporate image if not appropriately utilized. Given the results above and also considering the sources of information used by customers in the past year (see below), we don't believe that London Hydro's customer base has sufficient interest at this time to warrant actively utilizing these services as a customer communication channel.

Sources of information in past year	
Websites	66%
Newspaper	13%
Company Brochures	12%
Hydro Newsletters	11%
Television	9%
Hydro Bill Inserts	7%
Neighbours & Friends	6%
Radio	5%
Don't Know	4%
Contacted London Hydro	2%
Social Media	1%

In 2012 we will gather more information on lessons learned and operational cost from other utilities that have begun to adopt social media channels and re-evaluate the situation for 2013 and beyond.

Mobile applications on smart phone platforms such as Apple's iOS (iPhone, iPad, etc.), Blackberry and Android based phones are another emerging technology area experiencing massive growth. Applications for these platforms could provide additional channels of communications for customer engagement. The new web developments completed in 2011 and to be expanded in 2012 are being created with mobile devices in mind to provide a good user experience regardless of device and will also provide a platform for true mobile device capabilities in 2013/2014.

4.4.5. Mobile Workforce Automation

As new processes and interactions relating to meters or master data synchronization are introduced, such as MDM/R interfaces, timelines for processing of activities will become more stringent. For example, prior to 2011, the update of SAP with an activity such as a meter exchange would have no problem being processed several days after the event occurred; however as new complexities are introduced a delay in processing field work may result in data being dropped from the MDM/R service and require manual intervention to resend data once service activities have been completed.

We need to search for ways to optimize field work processing, initially within the constraints of current systems and processing requirements, but eventually moving towards a mobile workforce automation solution, where staff are connected live from field locations and can update service work in real time. It is anticipated that continual advancement in the smart phone and tablet space will reduce the initial expense for these systems through the use of commodity hardware moving into 2012/13.

4.5. IT Business Improvements

4.5.1. Project Management Processes

A new PMO phase methodology establishes a consistent method for project selection, control, and evaluation based on alignment with business goals and objectives. This Methodology consists of five phases, which are illustrated in the diagram below. Each phase is a distinct division of effort for a specified purpose during project delivery.

The phase methodology provides guidance for the development of deliverables, review, assessment, and approval of project outcomes during each review phase of project delivery to ensure quality control, completeness, feasibility and readiness to progress to the subsequent stage. This approach is currently being phased-in, utilizing key components as applicable to specific in-progress projects and will become the formal model for all new projects initiated by the PMO.

With our 2011 EBT Redesign project we opted to change the way we awarded work and separated define and design work from the build and implementation by selecting different vendors for each. The goal of this approach was to ensure a more solid solution design and identify deficiencies much earlier in the development process, thereby reducing the risk of costly issues in the later stages of the project. This split of work is so far working well and achieving our intentions and so is an option we may continue to utilize in some future projects, especially if there is perceived high risk in solution integrity and stability

4.5.2. Documentation Standards

Insufficient focus on documentation requirements has resulted in a situation where much of the functional and technical knowledge of enterprise systems is contained only within the minds of the people working on the systems and projects. This results in additional overhead when bringing in new internal and external resources as knowledge transfer becomes a costly exercise, especially with external consultants.

While the new project management processes will enforce the creation of documentation as deliverables, a set of documentation standards will also be created to define the purpose, structure and content of these deliverables. This will ensure that London Hydro obtains all of the necessary information to understand and maintain developments, avoiding repetitious costly knowledge transfers between consultants and ensuring we don't become dependent on external resources for London Hydro's ongoing operations.

4.5.3. Quality Assurance

Improved project management processes and documentation standards form part of an overall goal of providing quality assurance, which be a focus for improvement in 2011 and beyond, with a multi-faceted approach being taken in the following areas:

- Partnerships
- Delivery
- Organization Effectiveness

We shall stay the course with SAP, Intergraph and Oracle as strategic vendors/partners, aiming to extract maximum value from the technology investments that London Hydro has already made over the past years. We shall also look to work with these vendors, in particular SAP through the Lighthouse Council to help set direction and roadmaps for vendor development in the utility space. Additionally, we will look to cost sharing opportunities with other LDCs in services and knowledge.

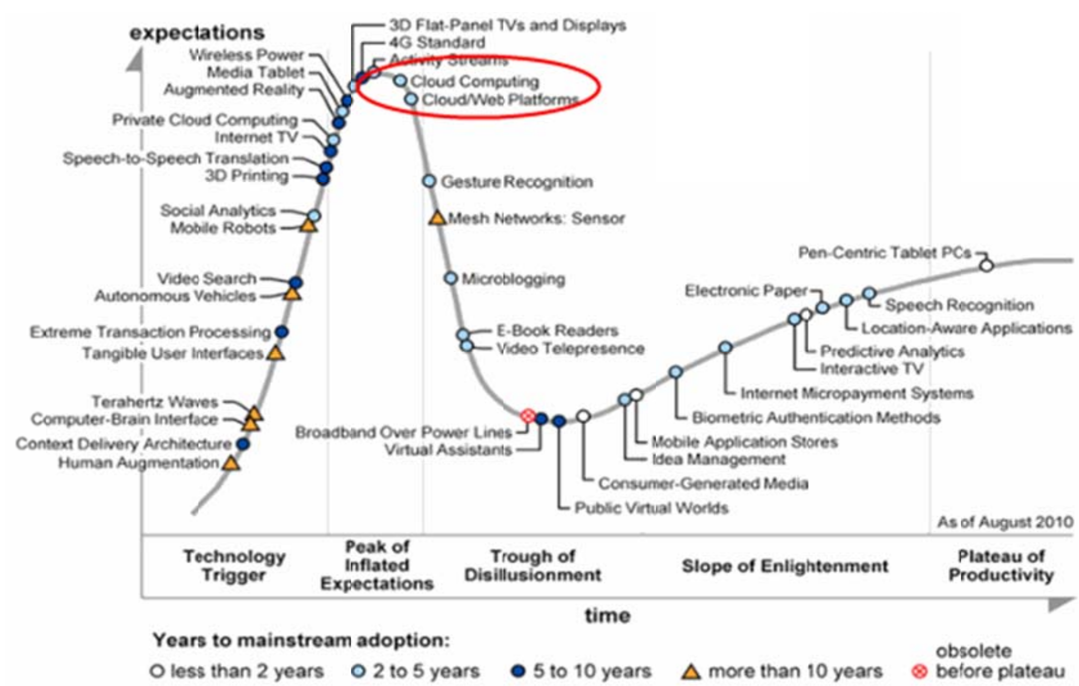
Internally we will be working to establish service level agreements with the business users and incorporate feedback loops to monitor our success in meeting these service levels. A more structured approach to testing methods and execution including upfront planning, utilization of automated testing systems and improvements to defect management processes will aid in more effective solution delivery. Staying current with an 'n-1' software release strategy will ensure current technology availability with proven solutions avoiding a position of being on the 'bleeding edge'.

Consolidation of the IT and PMO organizations as well as the incorporation of the Business Analyst functions will help to provide a more integrated team for provision of IT services and solutions. Utilizing more defined processes and better understanding of business needs (rather than wants) in the early phases of projects will improve project team effectiveness. Finally, defining a preferred IT supplier list and utilizing rate cards and clearly define statements of work will allow the project teams to spend more time focusing on delivering a quality solution with a quality vendor.

4.5.4. Cloud Computing/SaaS

Cloud computing is a paradigm shift in provision of IT infrastructure and services, which has arisen in recent times through advancements in virtualization and Internet/web specific standards. The concept itself is fairly old, with computing resources being treated as utility services, though these newer technologies have made implementation feasible on massive scales. This model is based around on demand access to services and systems via the Internet, removing the implementation details for end user organization. Software as a Service (SaaS) extends this model further providing preconfigured hosted and managed applications in the cloud, for example Microsoft will be moving towards this business model with the Microsoft Exchange platform used by many companies for email services.

Effectively leveraging cloud computing services may be able to offer London Hydro benefits in the form of reliability and scalability of services, which are achievable due to on demand virtualized resource provisioning and multi-tenancy within the cloud service. The other significant factor with these services which provides the major driver is reduction in capital expenditure on server resources. The pricing model for cloud computing services is generally usage based, considering CPU utilization, storage and network bandwidth which can be extremely favorable for some use cases since economies of scale of much larger companies are leveraged, removing the need for internal infrastructure, application expertise (in the case of SaaS), backup and disaster recovery capacity.



In 2011 we have started to evaluate cloud computing services particularly in the area of commodity services such as email, e.g. with Microsoft's Office 365 and Google's Gmail solutions. There are several concerns with these solutions (and other Cloud/SaaS hosted services that must be considered before moving ahead with solutions in this area:

- Many of these services are hosted in data centres within the United States and therefore subject to US legislation – this creates concern for Canadian organizations with respects to data privacy and needs further investigation to ensure data privacy.
- Several recent high profile failures of cloud services indicate that these solutions are still not fully matured and may warrant waiting for more robust architectures to be implemented by vendors.

Nevertheless, we will continue to evaluate options in this to determine feasibility for implementation with London Hydro's systems. This will be primarily focused around basic commodity type services such as corporate email and collaboration tools, which provide potential for reallocating some internal staff to focus on core business areas.

4.5.5. Communication & Collaboration Tools

Barriers to communication hinder effectiveness of teams working together. While meetings are a practical forum for some communication needs but can be very costly when considering the time commitment of staff and consultants and also create scheduling conflicts that can delay discussion until all parties are available together.

Often technology can provide more effective means for team discussion and collaboration, with less impact on productivity. Many tools also have the advantage of being able to capture and store communications, providing a zero-effort replacement for meeting minutes. Tools to facilitate collaboration between project team members will be evaluated by the IT team, including instant messaging and enhancements to the capabilities of the existing corporate intranet, or more enterprise centric portal solutions such as Microsoft SharePoint.

4.5.6. Quality Control

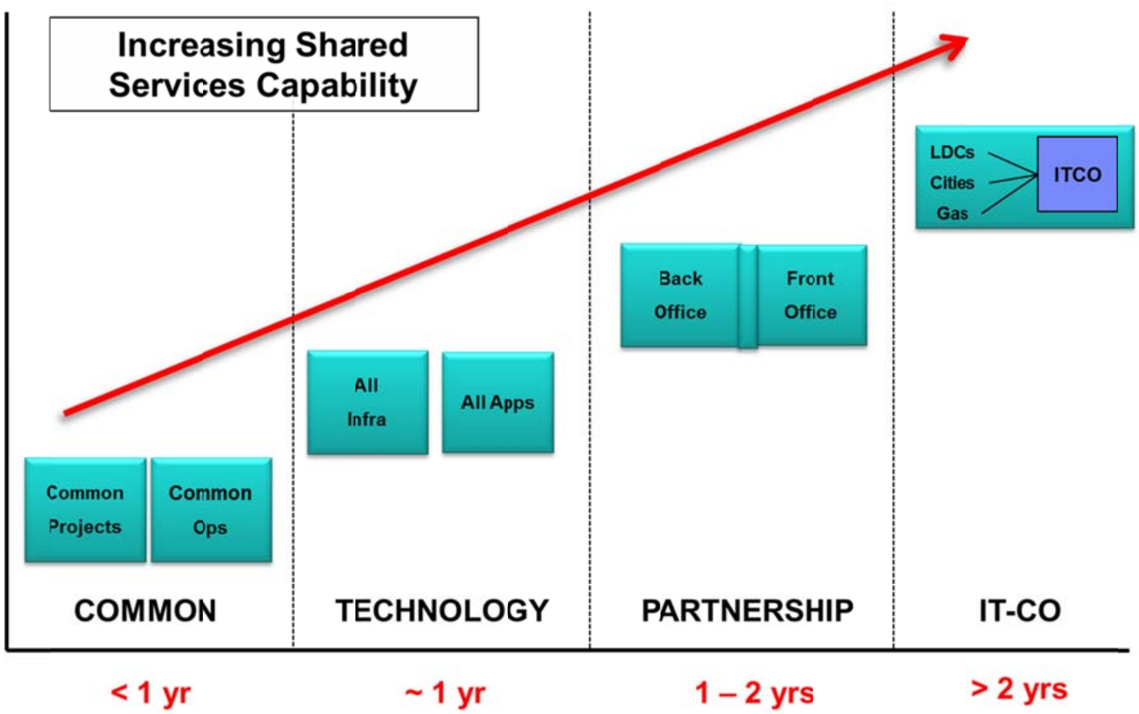
Our expectations of service and solution delivery should always be high, pushing to drive up quality of deliverables to meet our expectations, rather than lowering our expectations to what is given. Additional structure will be put into Quality Control processes with the aim of not only ensuring that solutions function correctly, but also as a mechanism to measure and quantify vendor/partner capability.

The quality control process will play a more significant part in projects, beginning during the design of solutions to allow testers to understand the solution being developed and prepare detailed and exhaustive test plans, rather than previous just-in-time efforts. The stages of testing and their definition will be better defined for consistency in execution and understanding across all projects and methods for tracking progress in execution and delivery as well as defect management will be formalized to avoid changing of processes mid-cycle.

Utilization of HP/SAP Quality Center to structure test planning, linking with requirements and management of defects will help to ensure these processes are well managed and test coverage addresses defined requirements. Automation of test execution will also be incorporated into the testing process with this tool, though the aim is not to develop automation of all tests, since this would be impractical in terms of both cost and effort – instead, test automation will be targeted to repeated regression test cases to reduce execution overhead of common cases, allowing testers to focus more on testing of new capabilities and more complex scenarios.

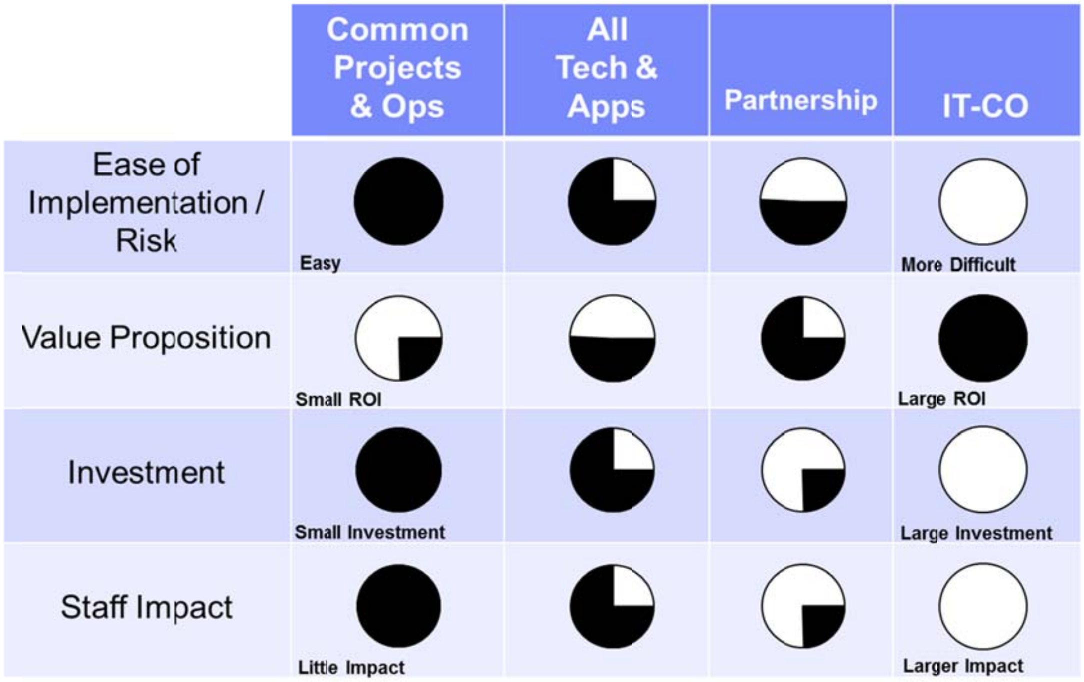
4.5.7. Shared Services

In late 2011 we have begun early discussions with several organizations around shared service models and will continue to explore and develop these possibilities in 2012. There are opportunities at many levels to leverage cost sharing from simple project and contract collaboration between organizations at the lower end, through shared IT infrastructure and application hosting, to hosted and operated services or unified IT organizations at the higher end. London Hydro currently operates with the City of London in a partnership type model for provision of water billing services and we believe that this model could be expanded to partnerships with other organizations in the region.



Our next steps in this area will be to continue discussions with the organizations we have already been in contact with – Hydro One, EnWin Utilities, Kitchener Utilities and

City of London to further define and detail options and cost models, which can then be evaluated to determine practicality and fit with London Hydro's corporate objectives.



4.6. Resourcing Structure

4.6.1. Organization Structure

In 2010 a new Project Management Office was formed to provide leadership and governance for corporate IT projects. An organization structure has evolved providing alignment between the activities and responsibilities of the PMO and IT service teams.

PMO	AMS	Infrastructure
Business Liaisons	Application Support	Servers and Storage
Strategic Planning	Break Fix	Networking and Security
Business Case Development	Minor Enhancements	IT Service Desk/Portal
Portfolio Management	Interfacing	Telecommunications
Project Management	Business Reporting	Remote Connectivity
IT Architecture	Business Intelligence	Desktop Support
Sourcing and Contracting	Customer Facing Portals	Disaster Recovery
IT Quality Assurance	Batch Processing	IT Asset Management
Benchmarking	EDI/EBT	Database Management
Governance		Middleware (PI, ESB)

4.6.2. Employee Development

While employees have their defined roles in the organization, London Hydro's scale dictates that management of the complex environment in which we work requires ownership of secondary roles to ensure effective coordination within and between internal teams. Moving forward employee development will need to consider the multiple hats that people wear on a day to day basis to ensure adequate training and capability can be provided in all areas.

With the IT organization there is a drive for training and certification process in three major areas, which need to be pursued to ensure that London Hydro's systems and processes utilize industry best practices:

- Development of SAP skills and knowledge
- Development of project management process
- Certification on core infrastructure technologies

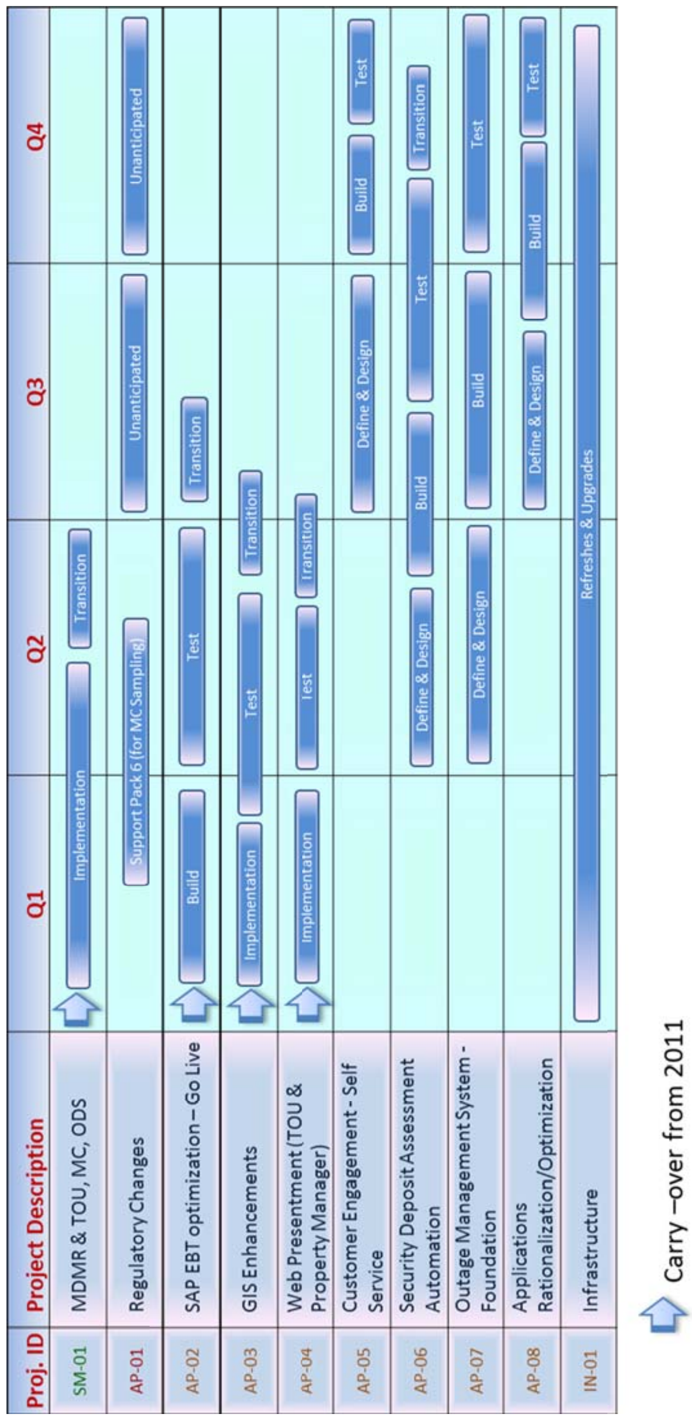
In 2011 the IT services organization averaged 20 hours training per employee and our intent is to increase this to 24 hours per employee in 2012, with specific focus on formal SAP and Microsoft training courses aiming towards certifications.

4.6.3. External Resourcing

The nature of enterprise systems being implemented to support the rapidly increasing complexities in the utility industry necessitates use of external consultants for project and support resourcing since it would not be practical to maintain an internal team of sufficient breadth and depth of knowledge to cover all possible requirements given the scale and scope of enterprise systems such as SAP. The key objectives with regards to external consultants over the next few years will be to obtain an effective balance of utilization and manage contract costs.

Out internal support team will be developed to enable handling of general break fix work, minor enhancements and reporting needs, with external consultants being utilized for their specific functional area experience and specialization where necessary. In conjunction with improved project management processes and documentation standards, we will increase focus on assimilation of knowledge from external resources into the support organization to extract greater value.

Section 5. Key Project Schedule



Section 6. Risks

6.1. Risk Areas

Within projects, risk areas can be generally categorized into one of three areas and these areas are also applicable at a program and strategic plan level; Scope, Schedule and Resources.

	Key Risks	Activities/Processes to Mitigate
Scope	Scope Creep or Gap Software Defects Hardware Defects Dependency Change Integration Defect	Clearly define deliverables and formal change request processes Define work breakdown structure in manageable components to ensure work is well understood Assign ownership and determine reasons for items not being accepted
Schedule	Project Dependencies Sub-component Delays Estimation Errors Decision Delay Hardware Delay Dependency on External Parties	Understand the basis of estimations and potential variations Identify critical milestones from a business or regulatory perspective Identify high risk dependencies Compare estimates to historical values
Resources	Purchased service delays Lack of funds Attrition of resources People joining the team late Scarcity of skills	Integrated resource plan within and across projects to ensure resource commitment and avoid overloading Ensure task resourcing estimates are not overly optimistic Identify all understaffed tasks Document all risks associated with purchased services Include schedule and funding for training, equipment and travel Determine the complete project cost

6.2. Specific Risks

6.2.1. Expectations & Scope

Project expectations and scope needs to be very clearly defined between business, PMO/IT, executive committee and vendor/partner resources to ensure everyone is working to the same goals, with an understanding of the underlying business objectives. Without a common understanding of the goals and objectives of a project it is not possible to adequately define success criteria and achieve acceptance.

It is better to have vision of where we want or need to be and carry out smaller projects as building blocks to reach that vision, since smaller better defined projects have a much greater chance for success than trying to do everything in a single big project. A multi-project approach also forces project teams to consider the solution components and interactions at a much earlier stage which will help to solidify scope.

6.2.2. Capabilities & Capacity

Availability of staff between multiple projects is a major factor in resource risk - with many projects simultaneously in progress, existing resource must balance their time between each. Looking at the number and types of resources available, the base and skill set of internal resources is not necessarily sufficient to realize plans without additional training. These factors also tie in with the issue of retention – how to ensure that we not only build the right team, but that we can retain that team.

Careful planning and adequate notice of requirements from the project management side is necessary to ensure resources are not over allocated and plans need to incorporate appropriate training to ensure we develop the base skill sets required. Ensuring retention of resources is primarily a process of recognition for work that is done and ensuring a balance of interesting work.

6.2.3. Regulatory Changes

Regulatory change is also a significant risk since it cannot necessarily be planned for. London Hydro is operating in a complex regulatory environment that has effectively been in an almost constant state of flux for some ten years. Efforts required to satisfy regulatory change consume resources that would otherwise be working towards the goals of our strategy and hence could delay progress.

6.2.4. Change in Corporate Direction

Recent discussions surrounding the possibility of a London utility company bringing other municipal utility services under the umbrella of London Hydro may result in a change to the IT strategy if this sees fruition. The current IT strategy and business plan is based around existing corporate objectives in the current business model – if these change as a result of a new structure then the strategy and plan will need to be re-evaluated to ensure ongoing alignment with corporate objectives.

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APPENDIX 2J – LEAD-LAG STUDY

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DETERMINATION OF WORKING CAPITAL REQUIREMENTS

Prepared for:
London Hydro, Inc.

London Hydro

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October 21, 2011

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Executive Summary

Purpose of Study

Navigant Consulting, Ltd. ("Navigant") has been retained by London Hydro, Inc. ("the Company") to perform a lead/lag study using the most recent data available and to derive the Company's working capital requirements for a historical 2010 "test" year. The purpose of this report is to provide the results of the lead-lag study and to determine the working capital requirements of the Company's distribution business.

Summary of Results

Based upon the results of our analysis, Navigant recommends a level of working capital equal to 11.42% of Operation and Maintenance, Administrative Expenses ("OM&A"). The estimated level of working capital is based upon an analysis of the accounting records for 2010.

Definition of Working Capital

Working capital is the amount of funds required to finance the day-to-day operations of any ongoing entity including a regulated utility. Regulated utilities typically include working capital in rate base for ratemaking purposes. A lead-lag study is the most accurate basis for determination of working capital and was used by Navigant for this purpose.

Lead-Lag Study

A lead-lag study is often used by utilities to quantify the level of working capital they require in order to finance their ongoing businesses. A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to the Company (or "lag") and the time between the Company's receipt of goods and services from its vendors and its payment for these goods and services at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 (or 366 if the year is a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of the Company's rate base for the purpose of deriving revenue requirements.

Organization of the Report

Section I of this report discusses the methods and assumptions used in determining the lead/lag approach. Included in 'Section I' is a description of two key concepts; the mid-point method and the statutory approach for services and materials provided and expensed.

Section II of this report discusses the lags associated with the Company's collections of revenues. Included in Section II is a description of the sources of such revenues and how they were treated for the purposes of deriving an overall revenue lag.

Section III presents a description of the various expenses and their attendant lead times. Included in the discussion on expense leads are the lead times on Cost of Power, Retailer Remittances, OM&A costs,

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

Interest on Long-Term Debt, Payments in Lieu of Taxes, Debt Reduction Charges, and the Goods and Services Tax ("GST")/Harmonized Sales Tax ("HST"). The methods used to calculate the expense lead times associated with each of the items, as well as the results from the application of the methods are described in this section.

Finally, Section IV presents the 2010 cash working capital requirements of London Hydro, Inc.'s distribution business including the working capital requirement associated with the GST/HST.

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Section I: Approach Employed to Perform the Lead-Lag Study

Methodology Employed for Lead-Lag Study

Performing a lead-lag study requires two key undertakings:

- Developing an understanding of how the regulated business works (i.e., in terms of products and services sold to customers or purchased from vendors and the collections), and payment policies and procedures that govern such transactions; and;
- Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of the Company's operations, interviews with personnel within the regulated utility's Financial Services, Human Resources, Payroll, and Customer Service departments were conducted. Some key questions that were addressed during the course of the interviews included:

- What is being sold (or bought)? If a service is being provided (purchased), over what time period was the service provided (or purchased);
- Who are the buyers (sellers);
- What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
- Are any changes expected to the terms for payment either driven by industry or internally by the Company? What is the basis for such changes (if any); and,
- How is payment made (i.e., cash, check, electronic funds transfer).

Except where otherwise noted, a calendar year 2010 data set was used in the analysis. Development of the data set entailed gathering raw data from the utility's General Accounting, Accounts Payable, Payroll, and Tax Systems. Once the raw data had been gathered from the multiple in-house systems, sampling and data validation was performed to the extent necessary and appropriate.

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Key Concepts

Defined below, are two key concepts that are used throughout this lead-lag study:

Mid-Point Method

When a service is provided to (or by) the company over a period of time, the service is deemed to have been provided (or received) evenly over a period, unless specific information regarding the provision (or receipt) of that service is available indicating otherwise. If both the service end date and the service start date are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([Service\ End\ Date - Service\ Start\ Date] + 1)}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the period, an alternative formula that is typically used is shown below. The formula uses the number of days in a year and the number of periods in a year:

$$\text{Mid-Point} = \frac{\frac{Number\ of\ Days\ in\ a\ Year}{Number\ of\ Time\ Periods\ in\ a\ Year}}{2}$$

Statutory Approach

In conjunction with the use of the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made by the Company. In some instances, particularly the GST/HST, the due date for payments are established by statute or by regulation with significant penalties in place for missing the due date. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

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Section II: Revenue Lags

A Revenue Lag is the time difference between when service is provided to a customer and when customer payments for such services are available to the Company. Interviews with the Company indicate that London Hydro's distribution business receives funds from retail customers and the Ontario Ministry of Finance via the Independent Electricity System Operator ("IESO") as part of the Ontario Clean Energy Benefit ("OCEB") Program. The OCEB is assumed to be 10% of the otherwise applicable cost of power bill. Retail customer Revenue Lag consists of four sequential components: a) Service Lag; b) Billing Lag; c) Collections Lag; and d) Payment Processing Lag. The lag times of each of these four components, when added together, results in the Revenue Lag for the purpose of calculating the working capital requirements of the Company.

A table summarizing the components of the total revenue lag of 64.64 days which London Hydro incurs are summarized Table 1 below. Table 2 summarizes the components of London Hydro's retail revenue lag.

Total Revenue Lag	Lag Days	Weighting Factor	Weighted Lag Days
Retail Revenue	64.90	90%	58.41
OCEB Revenue	62.29	10%	6.23
Total		**100%**	**64.64**

Table 1: Components of Total Revenue Lag

Component of Retail Revenue Lag	Lag Days
Service Lag	15.21
Billing Lag	18.00
Collections Lag	30.29
Payment Processing Lag	1.40
Total	**64.90**

Table 2: Components of Retail Revenue Lag

The estimation of each component of the retail revenue lag is described below.

Service Lag

The Service Lag is the time from the Company's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Interviews with Customer Service Staff at the Company indicated that all customers are on a monthly service schedule. Taking this information into account and using a mid-point methodology, the Service Lag was estimated to be 15.21 days.

Billing Lag

A Billing Lag is the time period between the end of a customer's service period and the time that the customer's bill is generated and provided to the customer. While customer consumption data was readily available subsequent to a meter read, interviews with the Company's Customer Service Department indicated that the key determinant of the Company's ability to provide a bill to its customer was the receipt of pricing data from the Ontario Independent Electricity System Operator ("IESO") which takes up to 10 business days. With this factored in, the Billing Lag is estimated to be 18.00 days.

Collections Lag

A Collections Lag measures the time period from when a customer's bill is provided, to the time period the customer provides a payment to the Company and when that payment is recorded in the Company's Billing System. This period of time is measured by analyzing the receivables aging data contained in receivables reports used by the Company for normal business purposes. Using such data provided by the Company for calendar year 2010, a dollar-weighted average collections lag of 30.29 days was determined for the Company's operations.

Payment Processing Lag

A Payment Processing Lag is the time period between the recording of a payment as having been received by the Company from a customer, and the payment being deposited into the Company's bank account. Based on interviews with the Company's customer service function, it was discovered that different payment methods result in different dates in which the payment is received in the Company's bank account. The following payment processing methods were considered in this study:

- If the customer paid by pre-authorized payment, or credit card, that payment is in the Company's bank account the same day;
- If the customer paid electronically, by internal mail, or via a site drop off, that payment is in the Company's bank account the next day;
- If the customer paid by external mail, or via a bank walk-in, that payment is in the Company's bank account two days after; and,
- Post dated cheques are held until the appropriate cheque date and deposited on that date. As there are no holds at the bank for the Company, payment is in the Company's bank account the same day it is deposited.

The exceptions would be if the payment were to be received on a Friday, Saturday, or a public holiday in which case additional time would be involved. When the exceptions are taken into account, an overall Payment Processing Lag of 1.40 days is the result and was used in the determination of the Company's overall revenue lag time.

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Section III: Expense Leads

An Expense Lead is the time period between when a good or service is provided to the Company and when the Company generally pays for that service. Expense Leads generally have both a Service Lead component (i.e., services are assumed to be provided to the Company evenly around the mid-point of the service period), and a Payment Lead component (i.e., the time period from the end of the service period to the time payment was made and the funds left the Company's possession). The following expenses were considered in this study:

- Cost of Power;
- Retailer Expenses;
- Payroll, Withholdings, and Employee Benefits;
- Operations, Maintenance, and Administrative ("OM&A") Expenses;
- Payments in Lieu of Taxes;
- Debt Reduction Charge; and,
- Interest Expense.

The Company's benefits and costs in terms of the working capital requirement associated with the GST/HST are discussed separately.

Cost of Power

The Company purchases its power supply requirements on a monthly basis from the Ontario IESO and pays for such supplies on a schedule defined within the IESO's billing and settlement procedures. Using information on actual payments made by the Company in 2010 and 2011, a dollar-weighted Expense Lead time of 32.12 days was quantified for the Company's cost of power procurements. This Expense Lead time consisted of an average Service Lead time of 15.25 days and an average Payment Lead time of 16.29 days, dollar-weighted to the payment amounts to the IESO. A summary of the calculation for the cost of power expense lead time is shown in Table 3 below.

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Delivery Month	Payment Amounts ($M)	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Lead Time (Days)
Apr-10	21.50	05/18/2010	15.00	18.00	33.00	6.88%	2.27
May-10	22.31	06/16/2010	15.50	16.00	31.50	7.14%	2.25
Jun-10	24.71	07/19/2010	15.00	19.00	34.00	7.91%	2.69
Jul-10[2]	10.00	08/10/2010	15.50	10.00	25.50	3.20%	0.82
Jul-10	20.59	08/18/2010	15.50	18.00	33.50	6.59%	2.21
Aug-10[2]	10.00	09/09/2010	15.50	9.00	24.50	3.20%	0.78
Aug-10	23.15	09/17/2010	15.50	17.00	32.50	7.41%	2.41
Sep-10	26.81	10/19/2010	15.00	19.00	34.00	8.58%	2.92
Oct-10	24.02	11/17/2010	15.50	17.00	32.50	7.69%	2.50
Nov-10	24.54	12/16/2010	15.00	16.00	31.00	7.86%	2.44
Dec-10	26.92	01/19/2011	15.50	19.00	34.50	8.62%	2.97
Jan-11	29.35	02/16/2011	15.50	16.00	31.50	9.39%	2.96
Feb-11	25.76	03/16/2011	14.00	16.00	30.00	8.25%	2.47
Mar-11	22.70	04/18/2011	15.50	18.00	33.50	7.27%	2.43
Total	**312.37**					**100.00%**	**32.12**

Table 3: Calculation of the Expense Leads associated with the Cost of Power

Retailer Remittance Expenses

London Hydro is responsible for remitting payments to third party electricity retailers for customers who have signed contracts with them. These payments consist of the difference between the actual bill for customer electricity used, and the price at which the contract was set between the electricity retailer and the customer. Payments are remitted to the electricity retailer on the same day as the customer bill is due to London Hydro. An expense lead time arises when customers do not pay their bill on time, whilst London Hydro still has to remit payments to the electricity retailers on the bill due date.

Using information on actual payments made by the Company in 2010, a dollar-weighted Expense Lead time of 29.21 days was quantified for the Company's retailer contract remittances. This Expense Lead time consisted of an average Service Lead time of 15.21 days and an average Payment Lead time of 15.84 days, dollar-weighted to the payment amounts to the retailers. A summary of the calculation for this remittance expense lead time is shown in Table 4 below.

Remittance Month	Total Lead Time	Payment Amount ($M)	Weighting Factor	Weighted Lead Time (Days)
Jan-10	39.77	0.82	3.94%	1.60
Feb-10	28.20	2.19	10.57%	3.07
Mar-10	32.77	2.56	12.37%	3.72
Apr-10	32.21	1.69	8.17%	2.55
May-10	32.14	3.88	18.73%	4.78
Jun-10	31.31	1.27	6.15%	1.92
Jul-10	31.19	1.30	6.29%	1.89
Aug-10	30.62	1.39	6.71%	2.05
Sep-10	30.77	1.05	5.07%	1.50
Oct-10	30.37	1.33	6.41%	1.92
Nov-10	30.77	1.97	9.50%	2.42
Dec-10	27.90	1.26	6.10%	1.77
Total		**20.69**	**100.00%**	**29.21**

Table 4: Calculation of Expense Leads associated with Retailer Remittance Expenses

Payroll, Withholdings, and Employee Benefits

The following items were considered under the umbrella of payroll, withholdings, and employee benefits:

- Regular Payroll;
- Board of Directors Payroll;
- Contribution to the Ontario Municipal Employee Retirement System ("OMERS");
- Group Life and Long Term Disability Insurance Coverage;
- Group Health, Medical, Dental, and Vision Coverage; and,
- Company contributions on account of Employee Health Care Spending Accounts.

When considered together and on a dollar-weighted basis, these items have an Expense Lead time of 7.41 days. A summary of the dollar-weighted expense lead time is provided in Table 5 below.

Description	Total Lead Time	Payment Amount ($M)	Weighting Factor	Weighted Lead Time (Days)
Payroll and Withholdings	7.45	22.13	85.34%	6.36
Board of Directors Payroll	14.13	0.11	0.42%	0.06
Pensions OMERS	34.37	1.46	5.61%	1.93
Long Term Insurance	(1.03)	0.37	1.44%	(0.01)
Life Insurance	(3.39)	0.09	0.36%	(0.01)
Health Benefits (Group Health, Dental, Vision)	(15.63)	1.22	4.71%	(0.74)
Retiree (Green Shield)	(15.54)	0.27	1.03%	(0.16)
Retiree (Desjardin)	(1.09)	0.23	0.88%	(0.01)
Retiree Recoverable	(3.55)	0.05	0.21%	(0.01)
Total		**25.93**	**100.00%**	**7.41**

Table 5: Payroll, Withholdings, and Employee Benefits Expense Lead Times

Payroll and Withholdings

Interviews with London Hydro's staff responsible for administering payroll and benefits indicated that all employees, excluding the Company's Board of Directors, are paid weekly. While pay-day is the Thursday following a Monday-Friday pay period end, payroll and withholding related funds including the Employer Health Tax, The Canada Pension Plan, and Employment Insurance are transferred electronically to the Company's payroll administrator on the Wednesday preceding the Thursday pay-day. Taking this information into account and using the Company's payroll and withholding data for 2010, a dollar-weighted Expense Lead time of 6.36 days was determined for payroll and withholdings. This included a Service Lead time of 3.50 days (the mid-point of a week) and a 4.00 day Payment Lead time since the funds are electronically transferred to the payroll administrator on the Wednesday following a Monday-Friday pay-period end.

Board of Directors Payroll

London Hydro's Board of Directors is paid monthly using a process similar to that of the Company's employees except that they are paid monthly, on the last Thursday of every month. The funds to make these payments are transferred by the Company to its payroll administrator on the Wednesday preceding the last Thursday of every month. Taking this information into account and using the Company's payroll and withholding data for 2010, a dollar weighted Expense Lead time of 0.06 days was determined. This lead time includes a Service Lead time component of 15.21 days and a Payment Lag time of about (1.17) days.

Contributions to the Ontario Municipal Employee Retirement System ("OMERS")

London Hydro makes its contributions to the OMERS the month following the calendar month for which contributions need to be made. Using data on actual payment dates and payment amounts during 2010, a dollar-weighted Expense Lead time of 1.93 days was determined. This lead time includes an average Service Lead component of about 15.21 days and a Payment Lead component of about 19.25 days.

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Group Long Term Disability Insurance

London Hydro pays its vendor of Group Long Term Disability Insurance in the same month as the services rendered. Using data on actual payment dates and payment amounts during 2010, a dollar-weighted Expense Lead time of (0.01) days were determined. This lag time includes an average Service Lead component of about 15.21 days and a Payment Lag component of about (16.17) days.

Group Life Insurance

London Hydro pays its vendor of Group Life Insurance in the same month as the services rendered. Using data on actual payment dates and payment amounts during 2010, a dollar-weighted Expense Lead time of (0.01) days were determined. This lag time includes an average Service Lead component of about 15.21 days and a Payment Lag component of about (18.33) days.

Group Health, Medical, Dental, and Vision

London Hydro pays its vendor for Group Health, Medical, Dental and Vision coverage in advance at the end of the prior month, or during the first week of the service month. Using data on actual payment dates and payment amounts during 2010, a dollar-weighted Expense Lag time of (0.74) days were determined. This lag time includes an average Service Lead component of about 15.21 days and a Payment Lag component of about (30.83) days.

Group Retiree Benefits

London Hydro has two vendors for Group Retiree Benefits. They are both paid in the same month as the services rendered, however the first vendor payments are at the beginning of the month, whereas the second vendor payments are during mid-month. Using data on actual payment dates and payment amounts during 2010, a dollar-weighted Expense Lead time of (0.16) days, and (0.01) days were determined for the first vendor and the second vendor respectively. The first vendor lag time includes an average Service Lead component of about 15.21 days and a Payment Lag component of about (30.83) days, whereas the second vendor lag time includes an average Service Lead component of about 15.21 days and a Payment Lag component of about (16.17) days.

London Hydro also bills its retirees for a portion of the benefits at the beginning of the service month. Using data on actual payments dates and net payment amounts (after recovery) during 2010, a dollar-weighted Expense Lag time of (0.01) days were determined. This lag time includes an average Service Lead component of about 15.21 days and a Payment Lag component of about (30.83) days.

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OM&A Expenses

The following items were the categories under the umbrella of OM&A expenses in this study:

- Building Maintenance;
- Business Equipment/Communication;
- Employee Development;
- Employee Expenses;
- Fleet Maintenance;
- G&A Professional Services;
- Materials & Supplies;
- Meeting Expenses;
- Miscellaneous;
- O&M Materials & Supplies;
- O&M Purchased Services;
- Studies & Special Projects; and,
- Pre-Paid Expenses.

These items were selected to be included within the umbrella of OM&A expenses because they represent activities typical to that undertaken by a regulated distribution company. Further, the items when considered together represent a major share of the Company's non power supply, payroll, and benefits related expenses.

When considered together and on a dollar-weighted basis, this basket of items has an Expense Lead time of 32.41 days for 2010. A summary of the calculation of the dollar-weighted expense lead time is provided in Table 6 below.

Description	Total Lead Time	Payment Amount ($M)	Weighting Factor	Weighted Lead Time (Days)
Building Maintenance	32.91	1.29	11.13%	3.66
Business Equipment & Communication	30.08	1.57	13.59%	4.09
Employee Development	29.21	0.18	1.56%	0.46
Employee Expenses	31.21	0.12	1.00%	0.31
Fleet Maintenance	30.72	0.38	3.29%	1.01
G&A Professional Services	34.64	4.10	35.50%	12.30
Materials & Supplies	30.79	0.29	2.49%	0.77
Meeting Expenses	32.29	0.01	0.04%	0.01
Miscellaneous	34.67	0.35	3.01%	1.04
O&M Materials & Supplies	30.23	0.03	0.22%	0.07
O&M Purchased Services	33.19	0.50	4.29%	1.42
Studies & Special Projects	30.76	0.07	0.60%	0.18
Pre-Paid Expenses	30.45	2.69	23.26%	7.08
Total		**11.56**	**100.00%**	**32.41**

Table 6: Expense Lead Time associated with OM&A Expenses

Building Maintenance

During 2010, the Company hired a number of vendors to provide it with various building maintenance services. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 3.66 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Business Equipment & Communication

During 2010, the Company hired a number of vendors to provide it with business & communications equipment, ranging from telephone, to wireless phones, to printer/photocopier maintenance. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 4.09 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Employee Development

During 2010, the Company hired a number of vendors to provide it with various employee developments, such as health & safety training. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 0.45 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Employee Expenses

During 2010, the Company had various employee expenses, ranging from newspaper subscriptions, to professional designation fees. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 0.31 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Fleet Maintenance

During 2010, the Company had various fleet maintenance expenses, ranging from scheduled vehicle maintenance, to rust proofing. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 1.01 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

G&A Professional Services

During 2010, the Company hired a number of consulting and contract firms to provide it with services ranging from engineering, to customer service to billing. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 12.30 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Materials & Supplies

During 2010, the Company had various materials & supplies expenses. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 0.77 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Meeting Expenses

During 2010, the Company had various meeting expenses, mainly consisting of 407 toll charges. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 0.01 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Miscellaneous

During 2010, the Company had various miscellaneous expenses, ranging from Bell Canada fees to Electrical Safety Authority fees. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 1.04 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

O&M Materials & Supplies

During 2010, the Company had various O&M Materials & Supplies expenses. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 0.07 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

O&M Purchased Services

During 2010, the Company had various O&M Purchased Services expenses. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 1.42 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

Studies & Special Projects

During 2010, the Company had various Studies & Special Projects expenses. Using data on actual payment dates and payment amounts during 2010, a dollar weighted expense lead time of 0.18 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

NAVIGANT

Pre-Paid Expenses

During 2010, the Company had various Pre-Paid OM&A expenses varying from Property Tax & Insurance payments to the City of London, to SAP IT license costs. Using data on actual payment dates, payment amounts, as well as the services rendered periods for the pre-payments, a dollar weighted expense lead time of 7.08 days was quantified. This lead time includes an assumed half-year or 182.50 days of service lead time as pre-paid expenses are for a whole year of rendered services The lead time also includes a payment lead time component which is the time period from when the payment was made, to the time when the services rendered ended.

Interest on Long Term Debt

The Company makes interest payments on its outstanding long term debt to (3) entities, the Royal Bank of Canada, the Toronto Dominion Bank, and the City of London. Interest payment installments for the entities above are 9 times, 3 times, and 4 times a year respectively.

Taking this information into account, a dollar-weighted Expense Lag time of 47.29 days associated with interest expense was determined. This lag time includes a Service Lead time of 182.50 days (i.e., the mid-point of a year).

Debt Reduction Charge

The Company makes a debt reduction charge monthly to the Ontario Electricity Finance Corporation ("OEFC"). The payment for the current charge month is made during the middle of the following month. Using actual payment dates and amounts from calendar year 2010, a dollar-weighted Expense Lead time of 31.33 days associated with the debt reduction charge was determined. This Expense Lead time includes an average of 15.21 days of Service Lead time.

Payments in Lieu of Taxes ("PILS")

The Company made payments in lieu of taxes to the Provincial Government via the OEFC, (10) times in 2010 during the middle of the charge month. There are no PILS payments for November or December as the PILS are paid off by October. Taking this information into account and using actual payments made in 2010, a dollar weighted Expense Lag time of (28.76) days was determined. This Expense Lag time includes an average 182.50 days of Service Lead time (i.e., the mid-point of a year).

Goods and Services Tax (GST) and Harmonized Sales Tax (HST)

The Expense Lead times associated with the following items that attract GST and HST were considered in the Navigant study:

- Customer Revenues including Cost of Power;
- Cost of Power;
- Retailer Expenses;
- Building Maintenance;
- Business Equipment & Communications;
- Employee Development;
- Employee Expenses;
- Fleet Maintenance;
- G&A Professional Services;

- Materials & Supplies;
- Meeting Expenses;
- Miscellaneous;
- O&M Materials & Supplies;
- O&M Purchased Services;
- Studies & Special Projects; and,
- Pre-Paid Expenses.

Effective July 1, 2010, the Ontario government implemented the harmonization of the Provincial Sales Tax with the Federal Goods and Service Tax into a single sales tax, HST. HST continues to have the same remittance and collection periods as the prior GST. Given the midyear change in tax rates, the 2010 Working Capital GST/HST amount was calculated using a blended tax rate of 9%, which takes into account the 5% GST rate for the first half of the year, and the 13% GST rate for the second half of the year.

A summary of the Expense Lead times associated with each of the above items is provided in Table 7 below. Note that the statutory approach described earlier in this report was used to determine the Expense Lead times associated with the Company's remittances and collections of GST and HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice).

Description	GST/HST Lead (Lag) Days	Working Capital Factor	Payment Amount ($M)	Working Capital ($M)
GST/HST Rate (Blended)			9.00%	
Revenues (Including COP)	(25.35)	(6.94%)	337.37	(2.11)
Cost of Power	44.57	12.21%	278.62	3.06
Retailer Expenses	45.11	12.36%	20.69	0.23
Building Maintenance	44.68	12.24%	1.29	0.01
Business Equipment/Communications	44.79	12.27%	1.57	0.02
Employee Development	44.39	12.16%	0.18	0.00
Employee Expenses	44.47	12.18%	0.12	0.00
Fleet Maintenance	46.22	12.66%	0.38	0.00
G&A Professional Services	44.28	12.13%	4.10	0.04
Materials & Supplies	44.83	12.28%	0.29	0.00
Meeting Expenses	47.91	13.13%	0.01	0.00
Miscellaneous	45.14	12.37%	0.35	0.00
O&M Materials & Supplies	45.17	12.38%	0.03	0.00
O&M Purchased Services	44.78	12.27%	0.50	0.01
Studies & Special Projects	43.50	11.92%	0.07	0.00
Pre-Paid Expenses	43.32	11.87%	2.69	0.03
Total				**1.31**

Table 7: Expense Lead Times associated with GST/HST Payments (Receipts)

NAVIGANT

Section IV: London Hydro, Inc.'s Working Capital Requirements

Having calculated the revenue lag, expense lead, and the net lag times, the next step in the process was to calculate the Company's working capital requirement. Using the results described under the discussion of revenue lags and expense leads, and applying them to the Company's expenses for 2010, the Company's working capital requirements are $35.65M. This amount represents 11.42% of the Company's OM&A expense including Cost of Power.

A summary of the Company's working capital requirements is provided in Table 8 below. Included within the working capital amount shown in Table 8 is the GST/HST benefit of $1.31M for 2010. The derivation of this amount is shown in Table 7 above.

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirement ($M)
Cost of Power	64.64	32.12	32.52	8.91%	278.62	24.82
Retailer Expenses	64.64	29.21	35.44	9.71%	20.69	2.01
OM&A Expenses	64.64	15.08	49.57	13.58%	33.41	4.54
PILS	64.64	(28.76)	93.41	25.59%	2.35	0.60
Interest Expense	64.64	47.29	17.36	4.75%	4.90	0.23
Debt Retirement Charge	64.64	31.33	33.32	9.13%	23.38	2.13
Total					**363.34**	**34.34**
GST/HST						1.31
Total – including GST/HST						**35.65**
Working Capital as a Percentage of OM&A including Cost of Power						**11.42%**

Table 8: 2010 Working Capital Requirement associated with Distribution Operations

APPENDIX 2K – WORKING CAPITAL ALLOWANCE USoA ACCOUNT DETAIL

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SUMMARY OF WORKING CAPITAL ALLOWANCE - DETAILS

	2009		2010		2011		2012		2013	
	2009 Actuals	Working Capital Allowance (15%)	2010 Actuals	Working Capital Allowance (15%)	2011 Actuals	Working Capital Allowance (15%)	2012 CGAAP Bridge	Working Capital Allowance (15%)	2013 CGAAP Test	Working Capital Allowance (11.42%)
OPERATION										
5005 Operation supervision & engineering	1,258,994	188,849	1,395,778	209,367	1,636,095	245,414	1,823,009	273,451	1,879,668	214,658
5010 Load dispatching	1,296,420	194,463	1,220,584	183,088	1,297,969	194,695	1,424,702	213,705	1,580,153	180,453
5012 Station buildings & fixtures expense	221,313	33,197	219,793	32,969	195,112	29,267	225,382	33,807	226,631	25,881
5016 Distribution station equipment - operation labour	152,951	22,943	119,253	17,888	165,190	24,779	167,940	25,191	162,547	18,563
5017 Distribution station equipment - operation supplies & expenses	458,250	68,738	303,181	45,477	363,340	54,501	352,394	52,859	346,028	39,516
5020 Overhead distribution lines & feeders - operation labour	27,132	4,070	24,787	3,718	60,204	9,031	35,485	5,323	37,151	4,243
5025 Overhead distribution lines & feeders - operation supplies & expenses	438,331	65,750	304,447	45,667	308,813	46,322	288,127	43,219	300,932	34,366
5030 Overhead subtransmission feeders - operation	-	-	-	-	-	-	-	-	-	-
5035 Overhead distribution transformers - operation	41,026	6,154	3,130	470	19,553	2,933	18,705	2,806	19,559	2,234
5040 Underground distribution lines & feeders - operation labour	85,665	12,850	61,852	9,278	51,197	7,680	71,825	10,774	72,210	8,246
5045 Underground distribution lines & feeders - operation supplies & expens	76,915	11,537	52,243	7,836	49,603	7,440	51,161	7,674	52,824	6,033
5055 Underground distribution transformers - operation	493,020	73,953	283,265	42,490	400,125	60,019	325,484	48,823	339,496	38,770
5065 Meter expense	643,483	96,522	747,504	112,126	846,336	126,950	1,022,305	153,346	762,099	87,032
5085 Miscellaneous distribution expense	1,964,358	294,654	2,420,493	363,074	2,400,326	360,049	2,435,557	365,334	2,556,988	292,008
5095 Overhead Distribution Lines and Feeders - Rental Paid	81,886	12,283	82,090	12,314	80,223	12,033	90,260	13,539	94,496	10,791
	7,239,744	**1,085,963**	**7,238,400**	**1,085,762**	**7,874,086**	**1,181,113**	**8,332,336**	**1,249,851**	**8,430,782**	**962,794**
MAINTENANCE										
5105 Maintenance supervision & engineering	1,050,377	157,557	1,242,742	186,411	1,420,801	213,120	1,648,298	247,245	1,747,339	199,546
5110 Maintenance of buildings & fixtures - distribution stations	45,280	6,792	44,335	6,650	92,967	13,945	66,053	9,908	67,009	7,652
5114 Maintenance of distribution station equipment	140,079	21,012	217,687	32,653	296,775	44,516	262,203	39,330	253,783	28,982
5120 Maintenance of poles, towers & fixtures	715,826	107,374	696,114	104,417	494,639	74,196	692,563	103,884	725,065	82,802
5125 Maintenance of overhead conductors & devices	1,028,495	154,274	1,065,656	159,848	1,366,596	204,989	1,358,234	203,735	1,421,976	162,390
5130 Maintenance of overhead services	146,430	21,965	177,095	26,564	207,094	31,064	188,518	28,278	197,365	22,539
5135 Overhead distribution lines & feeders - right of way	581,897	87,285	647,810	97,172	785,017	117,753	882,700	132,405	920,100	105,075
5145 Maintenance of underground conduit	263,195	39,479	362,082	54,312	126,356	18,953	303,883	45,582	317,588	36,269
5150 Maintenance of underground conductors & devices	805,664	120,850	880,178	132,027	1,125,571	168,836	912,040	136,806	950,176	108,510
5155 Maintenance of underground services	442,246	66,337	485,985	72,898	521,033	78,155	491,780	73,767	512,908	58,574
5160 Maintenance of line transformers	413,936	62,090	502,903	75,435	316,721	47,508	449,358	67,404	448,239	51,189
5172 Sentinel Lights - Materials and Expenses	-	-	-	-	162	24	45	7	47	5
5175 Maintenance of meters	9,792	1,469	66,007	9,901	28,453	4,268	277,781	41,667	275,364	31,447
	5,643,217	**846,484**	**6,388,594**	**958,288**	**6,782,185**	**1,017,327**	**7,533,456**	**1,130,018**	**7,836,959**	**894,980**

Cont'd…

SUMMARY OF WORKING CAPITAL ALLOWANCE - DETAILS (Cont'd)	2009		2010		2011		2012		2013	
	2009 Actuals	Working Capital Allowance (15%)	2010 Actuals	Working Capital Allowance (15%)	2011 Actuals	Working Capital Allowance (15%)	2012 Bridge	Working Capital Allowance (15%)	2013 CGAAP Test	Working Capital Allowance (11.42%)
BILLING AND COLLECTIONS										
5305 Supervision	88,553	13,283	87,365	13,105	85,214	12,782	83,617	12,543	80,443	9,187
5310 Meter reading expense	1,524,579	228,687	1,367,829	205,174	1,409,092	211,364	1,296,552	194,483	1,248,848	142,618
5315 Customer billing	2,175,953	326,393	2,011,563	301,734	2,033,959	305,094	1,883,599	282,540	1,789,354	204,344
5320 Collecting	1,272,225	190,834	1,306,745	196,012	1,369,719	205,458	1,247,366	187,105	1,197,519	136,757
5330 Collection Charges	(493,985)	(74,098)	(661,368)	(99,205)	(672,100)	(100,815)	(648,000)	(97,200)	(667,000)	(76,171)
5335 Bad debt expense	825,000	123,750	1,120,000	168,000	800,000	120,000	1,000,000	150,000	1,000,000	114,200
	5,392,325	**808,849**	**5,232,134**	**784,820**	**5,025,884**	**753,883**	**4,863,134**	**729,471**	**4,649,164**	**530,935**
COMMUNITY RELATIONS										
5410 Community relations - sundry	38,844	5,827	70,506	10,576	39,250	5,888	87,668	13,150	92,340	10,545
5415 Energy conservation	219,195	32,879	90,165	13,525	34,025	5,104	-	-	-	-
5420 Community safety program	94,113	14,117	90,504	13,576	105,456	15,818	109,384	16,408	112,997	12,904
	352,152	**52,823**	**251,175**	**37,677**	**178,731**	**26,810**	**197,052**	**29,558**	**205,337**	**23,449**
DONATIONS										
6205 Donations - re: assistance to customers for paying electricity bills	**100,000**	**15,000**	**100,000**	**15,000**	**100,000**	**15,000**	**100,000**	**15,000**	**100,000**	**11,420**
ADMINISTRATIVE AND GENERAL EXPENSES										
5605 Executive salaries & expenses	1,047,992	157,199	984,165	147,625	1,066,582	159,987	1,196,433	179,465	1,140,925	130,294
5610 Management salaries & expenses	842,539	126,381	1,291,293	193,694	1,256,619	188,493	1,355,174	203,276	1,378,848	157,464
5615 General administrative salaries & expenses	1,988,455	298,268	2,656,469	398,470	2,577,862	386,679	2,916,759	437,514	3,042,152	347,414
5620 Office supplies & expenses	1,039,106	155,866	1,114,368	167,155	1,222,633	183,395	1,255,779	188,367	1,225,718	139,977
5630 Outside services employed	472,272	70,841	1,516,867	227,530	1,184,623	177,693	1,240,295	186,044	1,168,753	133,472
5635 Property insurance	420,500	63,075	394,895	59,234	411,307	61,696	416,400	62,460	427,860	48,862
5640 Injuries & damages	297,775	44,666	215,132	32,270	248,767	37,315	270,861	40,629	277,054	31,640
5645 Employee pensions & benefits	133,685	20,053	182,541	27,381	223,313	33,497	246,543	36,981	249,208	28,460
5655 Regulatory expenses	571,922	85,788	408,819	61,323	389,494	58,424	523,000	78,450	537,700	61,405
5660 General advertising expenses	404,405	60,661	417,810	62,672	406,027	60,904	616,132	92,420	586,260	66,951
5665 Miscellaneous general expenses	1,286,805	193,021	1,365,210	204,782	1,395,733	209,360	1,458,665	218,800	1,662,265	189,831
5675 Maintenance of general plant	611,324	91,699	541,510	81,227	532,739	79,911	581,167	87,175	589,576	67,330
	9,116,780	**1,367,518**	**11,089,079**	**1,663,363**	**10,915,699**	**1,637,354**	**12,077,208**	**1,811,581**	**12,286,319**	**1,403,100**
COST OF POWER										
4705 Power Purchased	200,340,676	30,051,101	223,639,534	33,545,930	241,184,707	36,177,706	271,760,591	40,764,089	272,168,421	31,081,634
4708 Charges WMS	20,267,357	3,040,104	18,694,795	2,804,219	18,645,905	2,796,886	21,499,683	3,224,952	21,535,186	2,459,318
4714 Charges NW	16,139,973	2,420,996	19,568,047	2,935,207	20,633,041	3,094,956	23,107,461	3,466,119	23,491,357	2,682,713
4716 Charges CN	14,877,269	2,231,590	16,716,006	2,507,401	17,497,354	2,624,603	17,822,769	2,673,415	18,571,246	2,120,836
	251,625,275	**37,743,791**	**278,618,382**	**41,792,757**	**297,961,007**	**44,694,151**	**334,190,504**	**50,128,575**	**335,766,210**	**38,344,501**
TOTAL	**279,469,493**	**41,920,428**	**308,917,764**	**46,337,667**	**328,837,592**	**49,325,638**	**367,293,690**	**55,094,054**	**369,274,771**	**42,171,179**

EXHIBIT 3 – OPERATING REVENUE

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EXHIBIT 3 – OPERATING REVENUE

OVERVIEW OF OPERATING REVENUE

London Hydro's operating revenue for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and proposed 2013 Test Year is presented in this Exhibit. This Exhibit also provides a variance analysis of the material changes in operating distribution revenues from 2009 to 2013. Distribution revenue excludes revenue from commodity sales.

Revenues have been calculated using the appropriate OEB-approved Schedule of Rates and Charges for the applicable year. Total revenue includes OEB-approved specific service charges, rent from electric property, late payment charges, interest and other miscellaneous revenues. A summary of operating revenues is presented in Table 3-1 - Summary of Operating Revenue, and an analysis of variances follows on distribution revenue and other revenue with individual explanations.

Throughput Revenue:

Information related to London Hydro's throughput revenue includes details such as weather normalized forecasting methodology incorporating the impact of CDM programs, normalized volume and customer counts. The variance analysis on the actual and forecast information is provided in Table 3-1 - Summary of Operating Revenue below.

Other Distribution Revenue:

This includes revenues such as late payment charges, specific service charges, standard supply service administration charges, rent from electric property, retail service revenues, miscellaneous service revenues, and interest. Details of these operating revenues are presented in Table 3-26 - Other Distribution Revenues.

SUMMARY OF OPERATING REVENUE

Table 3-1 - Summary of Operating Revenue summarizes London Hydro's total base distribution revenue requirement calculated on London Hydro's forecasts, other distribution revenue and total service revenue requirement. The 2012 Bridge Year distribution revenue is based on London Hydro 2012 OEB-approved rates and London Hydro's forecast for customer counts and usage. The proposed distribution revenue for 2013 has been calculated based on 2013 proposed distribution rates and 2013 forecasted customer count and usage incorporating CDM effects.

Table 3-1 - Summary of Operating Revenue

Description	2009 Board Approved CGAAP	2009 Actual CGAAP	2010 Actual CGAAP	2011 Actual CGAAP	2012 Bridge CGAAP	2013 Test MIFRS
Distribution Revenues						
Residential	$ 35,663,122	$ 33,106,403	$ 36,494,211	$ 36,388,835	$ 35,998,298	$ 37,160,422
GS <50 kW	8,482,697	8,484,117	8,040,100	7,916,607	7,811,669	9,508,726
GS 50 to 4,999 kW	11,275,299	9,157,573	11,215,628	11,099,213	11,165,128	15,676,717
GS 50 to 4,999 kW (Co-Generation)	273,813	267,529	212,527	259,394	211,320	180,653
Standby Power	274,504	253,296	272,429	258,315	273,253	320,252
Large Use >5MW	1,370,000	927,644	1,537,205	1,660,915	1,601,744	1,363,682
Street Light	646,887	283,245	853,978	1,032,529	1,038,303	1,360,880
Sentinel	29,877	11,513	40,494	48,609	47,586	56,120
Unmetered Scattered Load	71,785	59,703	81,638	92,623	88,010	142,920
Base Distribution Revenue	**58,087,982**	**52,551,023**	**58,748,210**	**58,757,040**	**58,235,310**	**65,770,372**
Regulatory Adjustment		1,652,714				
Other Distribution Revenue						
Late Payment Charges	1,000,000	997,439	1,197,897	1,072,984	1,100,000	1,133,000
Specific Service Charges	847,800	796,561	828,825	820,197	813,000	839,000
Other Distribution Revenue	1,846,300	1,512,464	1,523,091	1,617,736	1,431,289	1,425,982
Total Other Revenue	**3,694,100**	**3,306,464**	**3,549,813**	**3,510,917**	**3,344,289**	**3,397,982**
Service Revenue	**$ 61,782,082**	**$ 57,510,202**	**$ 62,298,023**	**$ 62,267,957**	**$ 61,579,599**	**$ 69,168,354**
Variance from 2009 Board Approved		**-6.9%**	**0.8%**	**0.8%**	**-0.3%**	**12.0%**
Variance from prior year			**8.3%**	**0.0%**	**-1.1%**	**12.3%**

Note: This revenue analysis is net of transformer allowances for eligible customers.

THROUGHPUT REVENUE

Distribution Revenue and Variance Analysis:

London Hydro's distribution revenues and variances for 2009, 2010, 2011 and 2012 have been calculated using the OEB-approved distribution rates for 2009, 2010, 2011 and 2012 and the actual and projected billing quantities for those periods. The 2013 distribution revenue has been calculated using the rates proposed in this Application as discussed further in Exhibit 8 and forecasted billing quantities. Distribution revenue does not include commodity-related revenue.

London Hydro has provided an analysis of distribution revenues for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and proposed 2013 Test Year in Table 3-1 - Summary of Operating Revenue. The variance analysis for those periods is presented in summary Table 3-2 - Normalized Distribution Revenues, on the following page.

Table 3-2 - Normalized Distribution Revenues

	2009 Board Approved	2009 Actual CGAAP	2009 Actual Variance from 2009 Board Approved	2010 Actual CGAAP	2010 Actual Variance from 2009 Actual	2011 Actual CGAAP	2011 Actual Variance from 2010 Actual	2012 Bridge CGAAP	2012 Bridge Variance from 2011 Actual Year	2013 Test MIFRS	2013 Test Variance from 2012 Bridge Year
Distribution Revenue:											
Residential	$ 35,663,122	$ 33,106,403	$ (2,556,719)	$ 36,494,211	$ 3,387,808	$ 36,388,835	$ (105,376)	$ 35,998,298	$ (390,537)	$ 37,160,422	$ 1,162,124
GS <50 kW	8,482,697	8,484,117	1,420	8,040,100	(444,017)	7,916,607	(123,493)	7,811,669	(104,938)	9,508,726	1,697,057
GS 50 to 4,999 kW	12,094,123	9,817,752	(2,276,371)	11,933,701	2,115,949	11,785,065	(148,636)	11,830,122	45,057	16,357,369	4,527,248
GS 50 to 4,999 kW (Co-Generation)	300,122	290,246	(9,876)	234,310	(55,936)	288,220	53,910	234,467	(53,753)	209,853	(24,614)
Standby Power	367,384	346,176	(21,208)	365,309	19,133	351,195	(14,114)	366,133	14,938	413,132	46,999
Large Use >5MW	1,370,000	1,125,587	(244,413)	1,537,205	411,618	1,660,915	123,710	1,601,744	(59,171)	1,363,682	(238,061)
Street Light	646,887	283,245	(363,642)	853,978	570,733	1,032,529	178,551	1,038,303	5,774	1,360,880	322,577
Sentinel	29,877	11,513	(18,364)	40,494	28,981	48,609	8,115	47,586	(1,023)	56,120	8,534
Unmetered Scattered Load	71,785	59,703	(12,082)	81,638	21,935	92,623	10,985	88,010	(4,613)	142,920	54,911
Gross Distribution Revenue	**59,025,995**	**53,524,742**	**(5,501,253)**	**59,580,946**	**6,056,204**	**59,564,598**	**(16,348)**	**59,016,330**	**(564,616)**	**66,573,105**	**7,556,774**
Regulatory Adjustment		1,652,714									
Less Transformer Allow.											
GS 50 to 4,999 kW	(818,824)	(660,179)	158,645	(718,073)	(57,894)	(685,852)	32,221	(664,994)	20,858	(680,653)	(15,659)
GS 50 to 4,999 kW (Co-Generation)	(26,309)	(22,717)	3,592	(21,783)	934	(28,826)	(7,043)	(23,147)	5,679	(29,200)	(6,053)
Standby Power	(92,880)	(92,880)	-	(92,880)	-	(92,880)	-	(92,880)	-	(92,880)	-
Large Use >5MW	-	(197,943)	(197,943)	-	197,943	-	-	-	-	-	-
Base Distribution Revenue	**$ 58,087,982**	**$ 54,203,737**	**$ (3,884,245)**	**$ 58,748,210**	**$ 4,544,473**	**$ 58,757,040**	**$ 8,830**	**$ 58,235,310**	**$ (538,079)**	**$ 65,770,372**	**$ 7,535,063**
Variance from 2009 Board Approved			**-6.7%**		**1.1%**		**1.2%**		**0.3%**		**13.2%**
Variance from prior year %					**8.4%**		**0.0%**		**-0.9%**		**12.9%**

VARIANCE ANALYSIS

Comparison of 2009 Actual to 2009 Board Approved:

The 2009 Actual revenues were 6.7% lower than Board Approved revenues.

2009 Board Approved rates were implemented on Oct 1, 2009 and the 2009 Board Approved revenues reflect the application of those rates for a full 12 month time frame. Actual calendar year 2009 revenues presented above reflect revenues at 2008 rates for the first nine months of 2009 and 2009 rates for the remaining three months of 2009.

2009 rates increased by an average of 12% and revenues from those increased rates not reflected in the first nine months actual results for 2009 are approximately 9/12 *12% = 9%. The revenue variance of -6.7% is primarily due to the implementation date of the 2009 Board Approved rates.

The regulatory adjustment in 2009 includes the amount of pension costs associated with cash contributions paid to Ontario Municipal Employees Retirement Savings for the period of January 1, 2005 to April 30, 2006 in excess of amounts previously included in rates accumulated in 1508 Other Regulatory Assets – Sub-account Pension Contributions, plus amounts in 1518 Retail Cost Variance Account – Retail and 1548 Retail Cost Variance Account - STR approved for recovery – EB-2008-0235.

Comparison of 2010 Actual to 2009 Actual and 2009 Board Approved:

The 2010 Actual revenues were 8.4% higher than 2009 Actual and 1.1% higher than 2009 Board Approved revenues. The 2010 revenues are based on 2009 Board Approved rates for the full calendar year, plus a mechanistic rate adjustment of 1.18% effective May 1, 2010 less 0.43% tax savings adjustments.

Comparison of 2011 Actual to 2010 Actual and 2009 Board Approved:

The 2011 Actual revenues were similar to 2010 Actual and 1.2 % higher than 2009 Board Approved revenues. The 2011 revenues are based on 2010 Board Approved rates for the full calendar year, plus a mechanistic rate adjustment of 0.18 % effective May 1, 2011 less 0.95% tax savings adjustments.

The flow through effect in 2011 of the May 1, 2010 rate change combined with a slight decrease in customer growth and usage, offset by a small load growth of the Large User and Street Light customer classes, resulted in similar revenues to Year 2010. The increase of 1.2% from 2009 Board Approved amounts is comprised of rate adjustments in 2010 and 2011, plus customer and load growth accounting for the additional revenue over the period.

Comparison of 2012 Bridge to 2011 Actual and 2009 Board Approved:

The 2012 Bridge Year revenues are 0.9% lower than 2011 Actual and 0.3% higher than 2009 Board Approved revenues. The 2012 revenues are based on 2011 Board Approved rates for the full calendar year, plus a mechanistic rate adjustment of 0.18% less 1.16% tax savings adjustments effective May 1, 2012.

The decrease of 0.9% from 2011 to 2012 is the result of the May 1, 2012 rate adjustment and decrease in load growth along with conservation and demand management initiatives, specifically in the Residential and General Service < 50 kW customer classes, in spite of normal customer growth.

Comparison of 2013 Test Year to 2012 Bridge and 2009 Board Approved:

The 2013 Test Year revenues are forecasted to be 12.9% higher than 2012 Bridge Year revenues and 13.2% higher than 2009 Board Approved revenues.

The 2013 revenues reflect a rebasing increase of 10.4% over 2012, and significant impact is attributable to smart meter incremental OM&A and amortization expenses, as well as to customer and load growth. The revenues by rate class reflect the impacts of proposed cost allocation adjustments to bring revenue to cost ratios in line with Board recommended ranges.

The increase of 13.2% from 2009 Board Approved amounts is comprised of rate adjustments in the years of 2010, 2011, 2012 and 2013.

DISTRIBUTION REVENUE DATA BY CLASS

The following analysis in Table 3-3 - Distribution Revenues by Customer Class below, provides the throughput details by customer numbers, volumes, revenues and unit revenues by customer class.

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Table 3-3 - Distribution Revenues by Customer Class

	Customers	Consump. (kWh/kW)	Revenue ($)	Unit Rev. $/kWh/kW
Residential Class				
2009 Board Approved	131,936	1,091,392,572	35,663,122	0.0327
2009 Actual	129,058	1,067,772,436	33,106,403	0.0310
2010 Actual	134,971	1,146,523,466	36,494,211	0.0318
2011 Actual	134,465	1,128,904,736	36,388,835	0.0322
2012 Bridge	136,223	1,093,900,394	35,998,298	0.0329
2013 Test	138,004	1,081,449,144	37,160,422	0.0344
General Service < 50 kW				
2009 Board Approved	12,349	422,161,110	8,482,697	0.0201
2009 Actual	11,762	392,520,439	8,484,117	0.0216
2010 Actual	12,116	407,650,011	8,040,100	0.0197
2011 Actual	11,941	408,115,902	7,916,607	0.0194
2012 Bridge	11,955	396,446,167	7,811,669	0.0197
2013 Test	11,970	392,909,717	9,508,726	0.0242
General Service 50 to 4,999 kW				
2009 Board Approved	1,595	4,093,815	11,275,299	2.7542
2009 Actual	1,601	3,693,915	9,157,573	2.4791
2010 Actual	1,644	3,944,476	11,215,628	2.8434
2011 Actual	1,620	3,818,722	11,099,213	2.9065
2012 Bridge	1,641	3,824,518	11,165,128	2.9194
2013 Test	1,662	3,914,575	15,676,717	4.0047
GS 50 to 4,999 kW (Co-Generation) plus Standby Power				
2009 Board Approved	3	198,649	548,316	2.7602
2009 Actual	3	192,661	520,825	2.7033
2010 Actual	3	191,105	484,956	2.5376
2011 Actual	3	202,844	517,709	2.5523
2012 Bridge	3	193,378	484,573	2.5058
2013 Test	3	203,466	500,905	2.4619
Large Use >5MW				
2009 Board Approved	3	383,763	1,370,000	3.5699
2009 Actual	3	392,524	927,644	2.3633
2010 Actual	3	402,894	1,537,205	3.8154
2011 Actual	3	409,088	1,660,915	4.0600
2012 Bridge	3	385,417	1,601,744	4.1559
2013 Test	3	387,522	1,363,682	3.5190
Street Light				
2009 Board Approved	34,187	67,170	646,887	9.6307
2009 Actual	33,500	65,643	283,245	4.3149
2010 Actual	33,751	66,009	853,978	12.9374
2011 Actual	34,061	66,345	1,032,529	15.5629
2012 Bridge	34,530	66,804	1,038,303	15.5425
2013 Test	35,004	67,255	1,360,880	20.2346
Sentinel Lighting				
2009 Board Approved	734	2,342	29,877	12.7549
2009 Actual	730	2,278	11,513	5.0546
2010 Actual	727	2,260	40,494	17.9166
2011 Actual	707	2,203	48,609	22.0633
2012 Bridge	694	2,173	47,586	21.9033
2013 Test	681	2,130	56,120	26.3466
Unmetered Scattered Loads				
2009 Board Approved	1,581	5,326,529	71,785	0.0135
2009 Actual	1,521	5,569,256	59,703	0.0107
2010 Actual	1,484	5,524,132	81,638	0.0148
2011 Actual	1,557	5,645,414	92,623	0.0164
2012 Bridge	1,550	5,309,579	88,010	0.0166
2013 Test	1,544	4,994,818	142,920	0.0286

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Weather Normalized Load and Customer/Connection Forecast:

The purpose of this evidence is to present the process used by London Hydro to prepare the weather normalized load and customer/connection forecast used to design the proposed 2013 electricity distribution rates.

In summary, London Hydro has used the same regression analysis methodology used by a number of distributors in previous cost of service rate applications to determine a prediction model. With regard to the overall process of load forecasting, London Hydro submits that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. London Hydro has the data for the amount of electricity (in kWh) purchased from the IESO for use by London Hydro's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days and cooling degree days which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to billed kWh by rate class. A detailed explanation of the process is provided later in this evidence.

During proceedings related to the 2009 and 2010 cost of service applications for a number of other distributors, Intervenors expressed concerns with the load forecasting process that was proposed at the time by those distributors. During the review process of the 2009 cost of service applications, Intervenors suggested the regression analysis should be conducted on an individual rate class basis and the regression analysis would be based on monthly kWh by rate class. London Hydro reviewed the data required to conduct the regression analysis on an individual rate class basis and could only produce monthly consumption values (i.e. the amount consumed in the month not billed) by rate class from July 2009 onwards. In London Hydro’s view, this would not provide enough data items for the individual rate class regression analysis.

During the review of 2010 cost of service applications, Board staff and Intervenors expressed concern that the regression analysis assigned coefficients to some variables that were counter intuitive. For example, the customer variable would have a negative coefficient assigned to it which meant that, as the number of customers increased the energy forecast decreased. The 2010 applicants explained that this was related to the recent CDM savings in the utility, however, in the view of Board staff and Intervenors this was not a sufficient explanation. Further, the regression analysis indicated that some of the variables used in the load forecasting formula were not statistically significant and should not have been included in the equation. London Hydro has attempted to address these concerns in the load forecast used in this Application. Based on the Board's approval of this methodology in a number of previous cost of service applications, and based on the discussion that follows, London Hydro submits that its load forecasting methodology is reasonable for the purposes of this Application.

The following provides the material to support the weather normalized load forecast used by London Hydro in this Application.

Table 3-4 – Summary of Load and Customer / Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections						
2009 Board Approved	3,431.7			182,388		
2000 Actual	3,141.6			159,714		
2001 Actual	3,148.7	7.1	0.2%	164,499	4786	3.0%
2002 Actual	3,132.9	(15.8)	(0.5%)	155,699	(8801)	(5.3%)
2003 Actual	3,243.1	110.2	3.5%	167,458	11759	7.6%
2004 Actual	3,254.8	11.7	0.4%	169,662	2204	1.3%
2005 Actual	3,426.8	172.0	5.3%	171,264	1603	0.9%
2006 Actual	3,365.2	(61.6)	(1.8%)	174,120	2856	1.7%
2007 Actual	3,381.5	16.3	0.5%	176,842	2722	1.6%
2008 Actual	3,328.1	(53.4)	(1.6%)	179,247	2405	1.4%
2009 Actual	3,146.7	(181.4)	(5.5%)	178,177	(1070)	(0.6%)
2010 Actual	3,376.8	230.0	7.3%	184,699	6522	3.7%
2011 Actual	3,317.1	(59.6)	(1.8%)	184,357	(342)	(0.2%)
2012 Bridge	**3,284.6**	**(32.6)**	**(1.0%)**	**186,599**	**2242**	**1.2%**
2013 Test	**3,307.6**	**23.0**	**0.7%**	**188,871**	**2272**	**1.2%**

The information in Table 3-4 – Summary of Load and Customer / Connection Forecast above provides weather actual data from 2000 to 2011, while 2012 and 2013 are weather normalized. London Hydro does not have a process to properly adjust weather actual data to a weather normal basis. However, based on the process outlined in this Exhibit, a process to forecast energy on a weather normalized basis has been developed and used in this Application.

Total Customers and Connections are on a mid-year basis and Street Light, Sentinel Lights and Unmetered Loads are measured as connections.

Actual and forecasted billed amounts and numbers of customers/connections are shown in Table 3-5 – Billed Energy and Number of Customers / Connections by Rate Class, and customer/connection usage is shown in Table 3-6 – Annual Usage per Customer / Connection by Rate Class, on a rate class basis.

Table 3-5 – Billed Energy and Number of Customers / Connections by Rate Class

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL	Total
Billed Energy (GWh)									
2009 Board Approved	1,091.4	422.2	1,651.0	200.5	36.5	23.9	0.9	5.3	3,431.7
2000 Actual	1,041.9	356.8	1,456.0	238.6	20.4	20.5	0.9	6.4	3,141.6
2001 Actual	1,043.4	387.0	1,435.5	230.7	22.5	20.9	1.0	7.8	3,148.7
2002 Actual	1,060.8	421.6	1,391.1	211.8	18.6	20.8	0.9	7.2	3,132.9
2003 Actual	1,078.5	420.5	1,474.0	211.7	26.9	21.5	1.0	9.1	3,243.1
2004 Actual	1,065.2	410.5	1,504.1	220.0	23.2	22.0	0.9	8.8	3,254.8
2005 Actual	1,146.3	427.2	1,563.5	230.4	28.3	22.0	0.9	8.2	3,426.8
2006 Actual	1,102.3	412.3	1,562.7	227.3	30.9	22.7	0.9	6.3	3,365.2
2007 Actual	1,117.3	418.3	1,576.8	203.1	37.2	23.1	0.9	4.8	3,381.5
2008 Actual	1,119.7	418.6	1,535.1	185.2	39.8	23.3	0.9	5.6	3,328.1
2009 Actual	1,067.8	392.5	1,429.2	184.9	42.6	23.4	0.8	5.6	3,146.7
2010 Actual	1,146.5	407.7	1,551.6	195.1	46.0	23.5	0.8	5.5	3,376.8
2011 Actual	1,128.9	408.1	1,518.5	193.5	37.9	23.7	0.8	5.6	3,317.1
2012 Bridge	**1,093.9**	**396.4**	**1,529.9**	**194.6**	**39.9**	**23.8**	**0.8**	**5.3**	**3,284.6**
2013 Test	**1,081.4**	**392.9**	**1,565.9**	**195.6**	**42.0**	**24.0**	**0.8**	**5.0**	**3,307.6**
Number of Customers/Connections									
2009 Board Approved	131,936	12,349	1,595	3	3	34,187	734	1,581	182,388
2000 Actual	115,388	11,354	2,064	4	3	29,047	850	1,004	159,714
2001 Actual	116,945	11,901	1,494	4	3	32,088	798	1,268	164,499
2002 Actual	113,470	11,280	1,318	3	4	27,593	783	1,247	155,699
2003 Actual	121,195	11,824	1,465	3	4	30,537	822	1,608	167,458
2004 Actual	122,755	11,835	1,545	3	4	31,197	797	1,526	169,662
2005 Actual	124,049	11,853	1,555	3	3	31,602	790	1,409	171,264
2006 Actual	125,906	11,839	1,576	3	3	32,249	765	1,780	174,120
2007 Actual	128,164	11,918	1,595	3	3	32,971	759	1,429	176,842
2008 Actual	130,185	12,034	1,590	3	3	33,173	746	1,513	179,247
2009 Actual	129,058	11,762	1,601	3	3	33,500	730	1,521	178,177
2010 Actual	134,971	12,116	1,644	3	3	33,751	727	1,484	184,699
2011 Actual	134,465	11,941	1,620	3	3	34,061	707	1,557	184,357
2012 Bridge	**136,223**	**11,955**	**1,641**	**3**	**3**	**34,530**	**694**	**1,550**	**186,599**
2013 Test	**138,004**	**11,970**	**1,662**	**3**	**3**	**35,004**	**681**	**1,544**	**188,871**

Table 3-6 – Annual Usage per Customer / Connection by Rate Class

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Energy Usage per Customer/Connection (kWh per customer/connection)								
2009 Board Approved	8,272	34,186	1,035,139	66,828,460	12,163,164	700	1,167	3,369
2000 Actual	9,029	31,427	705,575	57,275,240	6,809,392	706	1,095	6,401
2001 Actual	8,922	32,521	961,067	57,674,079	7,495,692	653	1,226	6,123
2002 Actual	9,349	37,379	1,055,399	70,608,148	4,642,401	754	1,164	5,741
2003 Actual	8,899	35,563	1,005,860	70,576,181	6,713,946	705	1,172	5,634
2004 Actual	8,678	34,684	973,493	73,334,621	5,930,843	706	1,146	5,795
2005 Actual	9,241	36,043	1,005,383	76,786,538	8,926,921	697	1,145	5,829
2006 Actual	8,755	34,821	991,607	75,752,181	10,291,790	703	1,147	3,556
2007 Actual	8,718	35,099	988,378	67,708,310	12,404,711	700	1,150	3,368
2008 Actual	8,601	34,784	965,402	61,721,980	13,251,996	701	1,156	3,733
2009 Actual	8,274	33,373	892,687	61,634,875	14,196,962	698	1,146	3,662
2010 Actual	8,495	33,645	943,704	65,042,007	15,321,739	697	1,143	3,722
2011 Actual	8,396	34,179	937,089	64,516,383	12,639,556	694	1,149	3,626
2012 Bridge	**8,030**	**33,161**	**932,285**	**64,854,545**	**13,296,038**	**689**	**1,148**	**3,425**
2013 Test	**7,836**	**32,825**	**942,312**	**65,208,777**	**13,989,685**	**685**	**1,147**	**3,235**
Annual Growth Rate in Usage per Customer/Connection								
2009 Board App. Vs. 2009 Actual	(0.0%)	2.4%	16.0%	8.4%	(14.3%)	0.2%	1.9%	(8.0%)
2000 Actual								
2001 Actual	(1.2%)	3.5%	36.2%	0.7%	10.1%	(7.6%)	12.0%	(4.4%)
2002 Actual	4.8%	14.9%	9.8%	22.4%	(38.1%)	15.6%	(5.1%)	(6.2%)
2003 Actual	(4.8%)	(4.9%)	(4.7%)	(0.0%)	44.6%	(6.5%)	0.7%	(1.9%)
2004 Actual	(2.5%)	(2.5%)	(3.2%)	3.9%	(11.7%)	0.2%	(2.2%)	2.9%
2005 Actual	6.5%	3.9%	3.3%	4.7%	50.5%	(1.4%)	(0.1%)	0.6%
2006 Actual	(5.3%)	(3.4%)	(1.4%)	(1.3%)	15.3%	0.9%	0.2%	(39.0%)
2007 Actual	(0.4%)	0.8%	(0.3%)	(10.6%)	20.5%	(0.4%)	0.3%	(5.3%)
2008 Actual	(1.3%)	(0.9%)	(2.3%)	(8.8%)	6.8%	0.3%	0.5%	10.8%
2009 Actual	(3.8%)	(4.1%)	(7.5%)	(0.1%)	7.1%	(0.5%)	(0.9%)	(1.9%)
2010 Actual	2.7%	0.8%	5.7%	5.5%	7.9%	(0.2%)	(0.2%)	1.6%
2011 Actual	(1.2%)	1.6%	(0.7%)	(0.8%)	(17.5%)	(0.4%)	0.5%	(2.6%)
2012 Bridge	**(4.4%)**	**(3.0%)**	**(0.5%)**	**0.5%**	**5.2%**	**(0.7%)**	**(0.1%)**	**(5.6%)**
2013 Test	**(2.4%)**	**(1.0%)**	**1.1%**	**0.5%**	**5.2%**	**(0.7%)**	**(0.1%)**	**(5.5%)**

Load Forecast and Methodology:

London Hydro's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized purchased energy forecast is developed based on a multifactor regression model that incorporates independent variables that impact the monthly historical load pattern for London Hydro. Second, the weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast. Next, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast that has been determined from the regression model. The forecast of customers by rate class is determined using a geometric mean analysis. For those rate classes that use kW for the distribution volumetric billing determinant, an adjustment factor is applied to class energy forecast based on the historical relationship between kW and kWh.

A detailed explanation of the load forecasting process follows.

Purchased KWh Load Forecast:

An equation to predict total system purchased energy is developed using a multifactor regression model with the following independent variables: weather (heating and cooling degree days); Ontario real GDP; days in month; spring/fall seasonal "flag"; number of customers; CDM activity and number of peak hours. The regression model uses monthly kWh and monthly values of independent variables from January 1996 to December 2011 to determine a prediction formula with coefficients for each independent variable. This provides 192 monthly data points which represent a reasonable data set for use in a regression analysis. Consistent with the approach used by many other distributors in their cost of service applications, London Hydro submits that it is appropriate to review the impact of weather over the period January 1996 to December 2011 and then determine the average weather conditions over this period which would be applied in the prediction formula to determine a weather normalized forecast. However, in accordance with the OEB's Filing Requirements, London Hydro has also provided a sensitivity analysis showing the impact on the 2013 forecast of purchases assuming weather normal conditions are based on a 10 year average and on a 20-year trend of weather data.

Weather impacts on load are apparent in both the winter heating season, and in the summer cooling season. For that reason, both Heating Degree Days (i.e. a measure of coldness in winter) and Cooling Degree Days (i.e. a measure of summer heat) are modeled.

The following outlines the prediction model used by London Hydro to predict weather normal purchases for 2012 and 2013:

London Hydro's Monthly Predicted kWh Purchases

= Heating Degree Days * 53,992
+ Cooling Degree Days * 576,755
+ Ontario Real GDP Monthly * 1,098,966
+ Number of Days in the Month * 5,768,901
+ Spring Fall Flag * (8,830,913)
+ Number of Customer * 123
+ CDM Activity * (2.2)
+ Number of Peak Hours * 69,209
+ Intercept of (99,274,242)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix 3A.

The sources of data for the various data points are:

a) Environment Canada website for monthly heating degree day and cooling degree information. From 1992 to 2002, data from the London A weather stations was used and from 2003 onward data from the London CS weather station was used. Data from the London A weather station was not available after 2002 and data at the London CS weather station was not available before 2002;

b) The calendar provided information related to number of days in the month, the number of peak hours and the months defined to be spring or fall (i.e. March to May and September to November)

c) For 1996 to 2006 the source of data for the Ontario Real GDP information was the 2003 and 2008 Ontario Economic Outlook and Fiscal Review, Ontario Ministry of Finance. For 2007 and 2008, the source was the 2010 Ontario Economic Outlook and Fiscal Review - 2010

Fall Update. For 2009 to 2013, the 2011 Ontario Economic Outlook and Fiscal Review - 2011 Fall Update provided the Ontario Real GDP for those years.

d) The billing system provided historical monthly number of customers and the forecasted number of customer was based on the customer forecast discussed below.

e) The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values grow at constant value over the year. For the years 2006 to 2013, the addition of the monthly CDM activity values shown in Appendix 3A will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for London Hydro. These values reflect the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include draft verified results from 2011 programs that contribute to the four year licensed CDM kWh target of 156,640,000 assigned to London Hydro. The 2011 draft verified results are based on the Draft 2011 Results Report provided to London Hydro by the OPA on July 25, 2012. The 2011 draft verified results have been included in the CDM activity variable since these results have impacted the actual 2011 power purchases. The following Table 3-7 – 2011 Draft Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact outlines the adjustments made to the Net Energy Savings from the OPA 2006-2010 Final CDM Results to include the impact of the draft verified results from 2011 CDM programs and the persistent impact of the 2011 programs into 2012 and 2013. In addition, the table provides the Net Energy Savings from the OPA 2006-2010 Final CDM Results for the years 2006 to 2013. For 2013, the monthly values for the CDM activity variable will total 78,975,064 kWh which includes 56,958,662 kWh from the OPA final results plus 22,016,402 kWh reflecting the persistence of 2011 programs into 2013.

Table 3-7 – 2011 Draft Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact

London Hydro 4 Year 2011 to 2014 kWh target				
156,640,000				
2011	**2012**	**2013**	**2014**	**Total**
kWh savings from 2011 programs with presistent impact				
21,583,694	22,016,402	22,016,402	21,947,667	87,564,165
OPA 2010 Final Results - kWh				
2006	2007	2008	2009	
10,202,891	21,924,457	39,536,569	58,261,602	
2010	2011	2012	2013	
65,747,705	61,577,379	57,277,170	56,958,662	

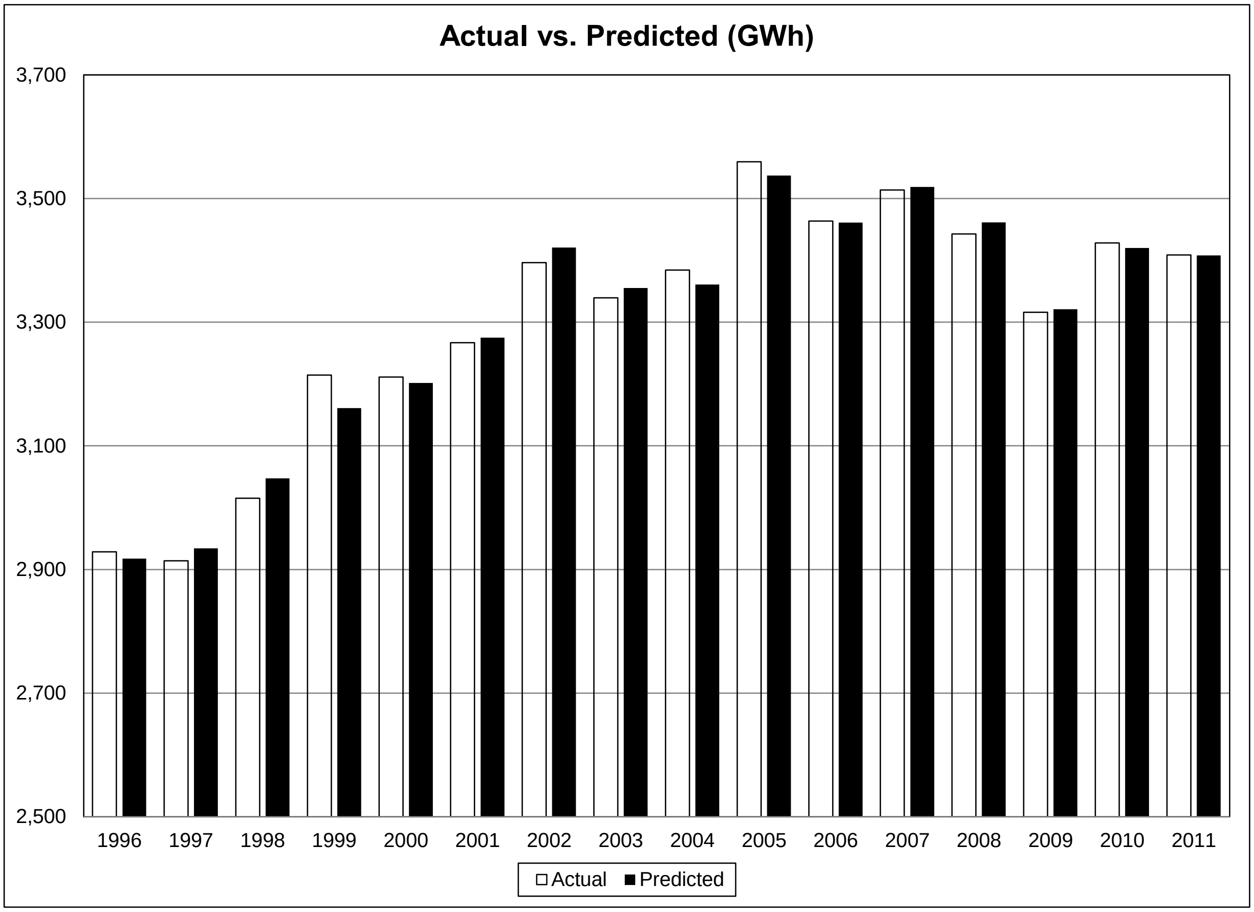
The impact of 2012 and 2013 CDM programs has not been included in the CDM activity variable since they do not impact the actual purchases used in the regression analysis. A discussion on how the load forecast is adjusted for 2012 and 2013 programs and how LRAM variance account values are determined by rate class is provided later in this schedule.

The prediction formula has the following statistical results:

Table 3-8 – Statistical Results

Statistic	Value
R Square	94%
Adjusted R Square	94%
F Test	392.5
T-stats by Coefficient	
Heating Degree Days	18.5
Cooling Degree Days	25.0
Ontario Real GDP Monthly %	25.5
Number of Days in Month	9.4
Spring Fall Flag	(7.2)
Number of Customers	2.6
CDM Activity	(8.4)
Number of Peak Hours	2.3
Intercept	(5.3)

The annual results of the above prediction formula compared to the actual annual purchases from 1996 to 2011 are shown in the chart below. The chart indicates the resulting prediction equation appears to be reasonable.



The following Table 3-9 – Total System Purchases outlines the data that supports the above chart. In addition, the predicted total system purchases for London Hydro are provided for 2012 and 2013. For 2012 and 2013 the system purchases reflect a weather normalized forecast for the full year. In addition, values for 2013 are provided on 10 year average and a 20 year trend assumption for weather normalization.

Table 3-9 – Total System Purchases

Year	Actual	Predicted	% Difference
Purchased Energy (GWh)			
1996	2,928.4	2,917.5	(0.4%)
1997	2,913.9	2,934.2	0.7%
1998	3,015.4	3,047.4	1.1%
1999	3,214.5	3,161.0	(1.7%)
2000	3,211.3	3,201.9	(0.3%)
2001	3,266.8	3,275.0	0.3%
2002	3,396.5	3,420.8	0.7%
2003	3,339.3	3,355.5	0.5%
2004	3,384.2	3,360.9	(0.7%)
2005	3,559.6	3,537.3	(0.6%)
2006	3,463.6	3,461.0	(0.1%)
2007	3,513.7	3,518.8	0.1%
2008	3,442.6	3,461.5	0.6%
2009	3,315.9	3,321.1	0.2%
2010	3,428.2	3,420.3	(0.2%)
2011	3,408.6	3,408.1	(0.0%)
2012 Weather Normal		**3,425.7**	
2013 Weather Normal		**3,469.2**	
2013 Weather Normal - 10 year average		**3,478.2**	
2013 Weather Normal - 20 year trend		**3,490.4**	

The weather normalized amount for 2013 is determined by using 2013 dependent variables in the prediction formula on a monthly basis together with the average monthly heating degree days and cooling degree days that occurred from January 1996 to December 2011 (i.e. 16 years). The 2013 weather normalized 10 year average amount reflects the average monthly heating degree days and cooling degree days that occurred from January 2002 to December 2011. The 20 year trend value is based on the trend in monthly heating degree days and cooling degree days that occurred from January 1992 to December 2011.

The weather normal 16 year average has been used in the power purchased forecast in this Application for the purposes of determining a billed kWh load forecast which is used to design rates. The 16 year average has been used as this is consistent with the period of time over which the regression analysis was conducted.

Billed KWh Load Forecast:

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. This adjustment has been made by London Hydro using the average loss factor from 1996 to 2011 of 1.0370. With this average loss factor the total weather normalized billed energy will be 3,303.5 GWh for 2012 (i.e. 3,425.7/1.0370) and 3,345.4 GWh for 2013 (i.e. 3,469.2/1.0370) before adjustments for 2012 and 2013 CDM programs.

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class:

Since the total weather normalized billed energy amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following Table 3-10 – Historical Customer / Connection Data. Historical customer/connection and billing data is only available for all rate classes from 2000 and onward.

Table 3-10 – Historical Customer / Connection Data

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL	Total
Number of Customers/Connections									
2000	115,388	11,354	2,064	4	3	29,047	850	1,004	159,714
2001	116,945	11,901	1,494	4	3	32,088	798	1,268	164,499
2002	113,470	11,280	1,318	3	4	27,593	783	1,247	155,699
2003	121,195	11,824	1,465	3	4	30,537	822	1,608	167,458
2004	122,755	11,835	1,545	3	4	31,197	797	1,526	169,662
2005	124,049	11,853	1,555	3	3	31,602	790	1,409	171,264
2006	125,906	11,839	1,576	3	3	32,249	765	1,780	174,120
2007	128,164	11,918	1,595	3	3	32,971	759	1,429	176,842
2008	130,185	12,034	1,590	3	3	33,173	746	1,513	179,247
2009	129,058	11,762	1,601	3	3	33,500	730	1,521	178,177
2010	134,971	12,116	1,644	3	3	33,751	727	1,484	184,699
2011	134,465	11,941	1,620	3	3	34,061	707	1,557	184,357

From the historical customer/connection data the growth rates in customers/ connections can be evaluated. The growth rates are provided in Table 3-11 – Growth Rate in Customer / Connections. The geometric mean growth rate in number of customers is also provided. The geometric mean approach provides the average compounding growth rate from 2000 to 2011.

Table 3-11 – Growth Rate in Customer / Connections

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Growth Rate in Customers/Connections								
2000								
2001	1.3%	4.8%	(27.6%)	(4.0%)	0.0%	10.5%	(6.2%)	26.2%
2002	(3.0%)	(5.2%)	(11.7%)	(25.0%)	33.3%	(14.0%)	(1.8%)	(1.6%)
2003	6.8%	4.8%	11.2%	(0.0%)	(0.0%)	10.7%	4.9%	28.9%
2004	1.3%	0.1%	5.4%	0.0%	(2.1%)	2.2%	(3.0%)	(5.1%)
2005	1.1%	0.2%	0.7%	(0.0%)	(19.2%)	1.3%	(0.9%)	(7.7%)
2006	1.5%	(0.1%)	1.3%	0.0%	(5.3%)	2.0%	(3.2%)	26.3%
2007	1.8%	0.7%	1.2%	0.0%	(0.0%)	2.2%	(0.8%)	(19.7%)
2008	1.6%	1.0%	(0.3%)	0.0%	0.0%	0.6%	(1.7%)	5.8%
2009	(0.9%)	(2.3%)	0.7%	0.0%	0.0%	1.0%	(2.2%)	0.5%
2010	4.6%	3.0%	2.7%	0.0%	0.0%	0.7%	(0.4%)	(2.4%)
2011	(0.4%)	(1.4%)	(1.4%)	0.0%	0.0%	0.9%	(2.8%)	4.9%
Geometric Mean	**1.3%**	**0.1%**	**1.3%**	**0.0%**	**(3.5%)**	**1.4%**	**(1.9%)**	**(0.4%)**

Except for the Cogeneration rate class, the resulting geometric mean was first applied to the 2011 customer/connection numbers to determine the forecast of customer/connections in 2012. Then the geometric mean was applied again to the 2012 value to determine the 2013 customer/connection forecast. For the Cogeneration rate class, the number of customers was held constant at three for 2012 and 2013 reflecting the actual number of customers for this class since 2005. The following Table 3-12– Customer / Connection Forecast outlines the forecast of customers and connections by rate class.

Table 3-12– Customer / Connection Forecast

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL	Total
Forecast Number of Customers/Connections									
2012	**136,223**	**11,955**	**1,641**	**3**	**3**	**34,530**	**694**	**1,550**	**186,599**
2013	**138,004**	**11,970**	**1,662**	**3**	**3**	**35,004**	**681**	**1,544**	**188,871**

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. The average annual usage per customer by rate class from 2000 to 2011 is provided in Table 3-13 – Historical Annual Usage per Customer.

Table 3-13 – Historical Annual Usage per Customer

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Annual kWh Usage Per Customer/Connection								
2000	9,029	31,427	705,575	57,275,240	6,809,392	706	1,095	6,401
2001	8,922	32,521	961,067	57,674,079	7,495,692	653	1,226	6,123
2002	9,349	37,379	1,055,399	70,608,148	4,642,401	754	1,164	5,741
2003	8,899	35,563	1,005,860	70,576,181	6,713,946	705	1,172	5,634
2004	8,678	34,684	973,493	73,334,621	5,930,843	706	1,146	5,795
2005	9,241	36,043	1,005,383	76,786,538	8,926,921	697	1,145	5,829
2006	8,755	34,821	991,607	75,752,181	10,291,790	703	1,147	3,556
2007	8,718	35,099	988,378	67,708,310	12,404,711	700	1,150	3,368
2008	8,601	34,784	965,402	61,721,980	13,251,996	701	1,156	3,733
2009	8,274	33,373	892,687	61,634,875	14,196,962	698	1,146	3,662
2010	8,495	33,645	943,704	65,042,007	15,321,739	697	1,143	3,722
2011	8,396	34,179	937,089	64,516,383	12,639,556	694	1,149	3,626

From the historical usage per customer/connection data the growth rate in usage per customer/connection can be reviewed. That information is provided in the following table: Table 3-14 – Growth Rate in Usage per Customer / Connection. The geometric mean growth rate has also been shown.

Table 3-14 – Growth Rate in Usage per Customer / Connection

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Growth Rate in Customer/Connection								
2000								
2001	(1.2%)	3.5%	36.2%	0.7%	10.1%	(7.6%)	12.0%	(4.4%)
2002	4.8%	14.9%	9.8%	22.4%	(38.1%)	15.6%	(5.1%)	(6.2%)
2003	(4.8%)	(4.9%)	(4.7%)	(0.0%)	44.6%	(6.5%)	0.7%	(1.9%)
2004	(2.5%)	(2.5%)	(3.2%)	3.9%	(11.7%)	0.2%	(2.2%)	2.9%
2005	6.5%	3.9%	3.3%	4.7%	50.5%	(1.4%)	(0.1%)	0.6%
2006	(5.3%)	(3.4%)	(1.4%)	(1.3%)	15.3%	0.9%	0.2%	(39.0%)
2007	(0.4%)	0.8%	(0.3%)	(10.6%)	20.5%	(0.4%)	0.3%	(5.3%)
2008	(1.3%)	(0.9%)	(2.3%)	(8.8%)	6.8%	0.3%	0.5%	10.8%
2009	(3.8%)	(4.1%)	(7.5%)	(0.1%)	7.1%	(0.5%)	(0.9%)	(1.9%)
2010	2.7%	0.8%	5.7%	5.5%	7.9%	(0.2%)	(0.2%)	1.6%
2011	(1.2%)	1.6%	(0.7%)	(0.8%)	(17.5%)	(0.4%)	0.5%	(2.6%)
Geometric Mean	**(0.7%)**	**0.8%**	**2.6%**	**1.1%**	**5.8%**	**(0.2%)**	**0.4%**	**(5.0%)**

For the forecast of usage per customer/connection the historical geometric mean was applied to the 2011 usage to determine the 2012 forecast. The geometric mean is applied again to the 2012 value to determine the 2013 forecast and the resulting usage forecast is as follows:

Table 3-15 – Forecast Annual kWh Usage per Customer / Connection

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Forecast Annual kWh Usage per Customers/Connection								
2012	8,340	34,441	961,577	65,218,423	13,370,638	693	1,154	3,444
2013	8,285	34,704	986,705	65,928,102	14,144,006	692	1,160	3,271

With the preceding information the non-normalized weather billed energy forecast can be determined by applying the forecast numbers of customers/connections from Table 3-12– Customer / Connection Forecast by the forecast of annual usage per customer/connection from Table 3-15 – Forecast Annual kWh Usage per Customer / Connection. The resulting non-normalized weather billed energy forecast is shown in the following Table 3-16 – Non-normalized Weather Billed Energy Forecast (GWh).

Table 3-16 – Non-normalized Weather Billed Energy Forecast (GWh)

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL	Total
NON-normalized Weather Billed Energy Forecast (GWh)									
2012 (Not Normalized)	1,136.1	411.7	1,577.9	195.7	40.1	23.9	0.8	5.3	3,391.7
2013 (Not Normalized)	1,143.4	415.4	1,639.7	197.8	42.4	24.2	0.8	5.0	3,468.8

The non-normalized weather billed energy forecast has been determined, however, this needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 3,303.5 GWh for 2012 and 3,345.4 GWh for 2013 before adjustments for 2012 and 2013 CDM programs.

The difference between the non-normalized and normalized forecast adjustments is 88.2 GWh in 2012 (i.e. 3,391.7 – 3,303.5) and 123.4 GWh in 2013 (i.e. 3,468.8 – 3,345.4). The difference is assumed to be associated with moving the forecast from a non-normalized to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. Based on the weather normalization work completed by Hydro One for London Hydro for the cost allocation study, which has been used to support this Application, it was determined that the weather sensitivity by rate classes is as follows:

Table 3-17 – Weather Sensitivity by Rate Class

Table 3-17: Weather Sensitivity by Rate Class							
Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Weather Sensitivity							
82.5%	82.5%	65.0%	0.0%	0.0%	0.0%	0.0%	0.0%

For the GS > 50 kW class the weather sensitivity amount of 65% was provided in the weather normalization work completed by Hydro One. For the Residential and General Service < 50 kW classes, it is has been assumed in previous cost of service applications that these two classes are 100% weather sensitive. Intervenors expressed concern with this assumption and have suggested that 100% weather sensitivity is not appropriate. London Hydro agrees with this position but also submits that the weather sensitivity for the Residential and GS < 50 kW classes should be higher than the GS > 50 kW class. As a result, London Hydro has assumed the weather sensitivity for the Residential and General Service < 50 kW classes to be mid-way between 100% and 65%, or 82.5%.

The difference between the non-normalized and normalized forecast of 88.2 GWh in 2012 and 123.4 GWh in 2013 has been assigned on a *pro rata* basis to each rate class based on the above level of weather sensitivity.

In addition a manual adjustment has been made to reflect the impact of 2012 and 2013 CDM programs on the load forecast. This adjustment reflects the "gross" impact of 2012 and 2013 CDM programs on the load forecast. The gross impact includes the net results measured by the OPA plus an estimate of the average net to gross adjustment reflecting gross and net savings information provided in the OPA 2006-2010 Final CDM Results. The net results provide a measurement of the program effectiveness used to achieve the LDC targets. The gross results include the net results plus the estimated impact of customers participating in a program even if an incentive was not provided to participate. In the past this has been termed the level of "free ridership". In other words, the gross results include the results from those who participated in the program because there was an incentive plus those who participated even if there was not an incentive. In London Hydro's view it is the gross level that impacts the load forecast.

The following Table 3-18 – Average Net to Gross Percentage outlines the average net to gross factor of 64.4% based on information provided in the OPA 2006-2010 Final CDM Results for London Hydro.

Table 3-18 – Average Net to Gross Percentage

Year	OPA 2006-2010 Final CDM Results (Gross)	OPA 2006-2010 Final CDM Results (Net)	# Difference	% Difference of Net
2006	11,394,626	10,202,891	1,191,735	11.7%
2007	50,112,115	21,924,457	28,187,658	128.6%
2008	65,754,853	39,536,569	26,218,284	66.3%
2009	92,045,176	58,261,602	33,783,574	58.0%
2010	103,965,974	65,747,705	38,218,269	58.1%
2011	99,855,888	61,577,379	38,278,509	62.2%
2012	94,055,674	57,277,170	36,778,504	64.2%
2013	93,428,939	56,958,662	36,470,277	64.0%
Total	610,613,245	371,486,435	239,126,810	64.4%

As previously discussed, the 2011 draft verified savings from 2011 CDM programs are known and has been used in the CDM activity variable included in the regression analysis supporting the prediction formula. However, the 2011 draft verified results impacts on the expected savings from 2012 to 2014 programs in order to achieve the licensed 4 year CDM target. Based on Table 3-19– Schedule to Achieve 4 Year kWh CDM Target, the 2011 draft verified savings will contribute 55.9% to the four year target. In Table 3-19– Schedule to Achieve 4 Year kWh CDM Target the 2011 results are consistent with the information provided in Table 3-7 – 2011 Draft Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact. The table indicates that assuming persistence, 2012 to 2014 programs will need to achieve 7.3% of the four year target each year in order to achieve the target.

Table 3-19– Schedule to Achieve 4 Year kWh CDM Target

4 Year 2011 to 2014 kWh target					
156,640,000					
	2011	**2012**	**2013**	**2014**	**Total**
2011 Programs	13.8%	14.1%	14.1%	14.0%	55.9%
2012 Programs		7.3%	7.3%	7.3%	22.0%
2013 Programs			7.3%	7.3%	14.7%
2014 Programs				7.3%	7.3%
	13.8%	21.4%	28.8%	36.1%	100.0%
kWh					
2011 Programs	21,583,694	22,016,402	22,016,402	21,947,667	87,564,165
2012 Programs		11,512,639	11,512,639	11,512,639	34,537,918
2013 Programs			11,512,639	11,512,639	23,025,278
2014 Programs				11,512,639	11,512,639
	21,583,694	33,529,041	45,041,680	56,485,584	156,640,000

The above Table 3-19– Schedule to Achieve 4 Year kWh CDM Target suggests that in 2012, the savings from 2012 will be 11,512,639 kWh on a net basis. However on a gross basis this amount would be 11,512,639 times 1.644 (i.e. the net to gross factor determined in Table 3-18 – Average Net to Gross Percentage) or 18,923,356 kWh. In London Hydro's view, the 2012 load forecast should be adjusted by 18,923,356 kWh to reflect CDM savings from 2012 programs. As discussed above in regards to the CDM Activity variable, the persistent savings from 2011 programs in 2012 have been reflected in the prediction formula.

The above Table 3-19– Schedule to Achieve 4 Year kWh CDM Target also suggest that in 2013, the savings from 2012 and 2013 programs will be 11,512,639 kWh times two or 23,025,278 kWh on a net basis. However on a gross basis this amount would be 23,025,278 times 1.644 or 37,846,712 kWh. In London Hydro's view, the 2013 load forecast should be adjusted by 37,846,712 kWh to reflect CDM savings from 2012 and 2013 programs.

In accordance with the Board Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003), issued April 26, 2012, it is London Hydro's understanding that as part of this Application, expected CDM savings in 2013 from 2011, 2012 and 2013 programs will need to be established for LRAM variance accounts purposes. It is also London Hydro's understanding that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected that the net level of savings will be used for LRAM calculations. As a result, it is London Hydro's view the units used for the 2013 LRAM variance account should also be on a net basis. Based on the net information in Table 3-19– Schedule to Achieve 4 Year kWh CDM Target, London Hydro expects to achieve 45,041,680 net kWh savings in 2013 from 2011 to 2013 CDM programs. For LRAM variance account purposes, the Table 3-20 – 2013 Expected Savings for LRAM Variance Account outlines how this expected savings has been allocated to rate class using the 2013 information from Table 3-16 – Non-normalized Weather Billed Energy Forecast (GWh). The expected kW saving has also been provided for those classes billed distribution charges on a kW basis using the average kW/KWh factors from Table 3-23 – Historical kW/kWh Ratio per Applicable Rate Class.

Table 3-20 – 2013 Expected Savings for LRAM Variance Account

	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL	Total
kWh	14,846,777	5,394,098	21,291,147	2,568,223	550,978	314,632	10,252	65,573	45,041,680
kW where applicable			53,225	5,087	2,671	883	28		61,895

The following Table 3-21 – Alignment of Non-normal to Weather Normal Forecast outlines how the classes have been adjusted to align the non-normalized forecast with the normalized forecast and reflect the adjustments discussed above.

Table 3-21 – Alignment of Non-normal to Weather Normal Forecast

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL	Total
Non-normalized Weather Billed Energy Forecast (GWh)									
2012 Non-Normalized Bridge	1,136.1	411.7	1,577.9	195.7	40.1	23.9	0.8	5.3	3,391.7
2013 Non-Normalized Test	1,143.4	415.4	1,639.7	197.8	42.4	24.2	0.8	5.0	3,468.8
Weather Adjustment (GWh)									
2012	(35.9)	(13.0)	(39.3)	0.0	0.0	0.0	0.0	0.0	(88.1)
2013	(49.5)	(18.0)	(55.9)	0.0	0.0	0.0	0.0	0.0	(123.3)
CDM Adjustment (GWh)									
2012	(6.3)	(2.3)	(8.8)	(1.1)	(0.2)	(0.1)	(0.0)	(0.0)	(18.9)
2013	(12.5)	(4.5)	(17.9)	(2.2)	(0.5)	(0.3)	(0.0)	(0.1)	(37.8)
Weather Normalized Billed Energy Forecast (GWh)									
2012 Normalized Bridge	1,093.9	396.4	1,529.9	194.6	39.9	23.8	0.8	5.3	3,284.6
2013 Normalized Test	1,081.4	392.9	1,565.9	195.6	42.0	24.0	0.8	5.0	3,307.6

Billed KW Load Forecast:

There are five rate classes that charge volumetric distribution on per kW basis. These include GS > 50 kW, Large User, Cogeneration, Street Lighting and Sentinel Lighting. As a result, the energy forecast for these classes needs to be converted to a kW basis for rate setting purposes. The forecast of kW for these classes is based on a review of the historical ratio of kW to kWhs and applying the average ratio to the forecasted kWh to produce the required kW.

The following Table 3-22 – Historical Annual kW per Applicable Rate Class outlines the annual demand units by applicable rate class.

Table 3-22 – Historical Annual kW per Applicable Rate Class

Year	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	Total
Billed Annual kW						
2000	3,409,084	449,942	221,180	56,986	2,585	4,139,777
2001	3,663,518	440,191	196,318	63,078	2,734	4,365,840
2002	3,492,609	376,632	171,049	54,787	2,517	4,097,595
2003	3,703,095	409,593	185,848	60,395	2,614	4,361,545
2004	3,730,755	425,269	168,537	61,623	2,477	4,388,662
2005	3,856,524	435,548	186,551	62,274	2,455	4,543,351
2006	3,870,802	438,386	187,536	63,546	2,349	4,562,619
2007	3,944,920	421,485	203,743	64,717	2,369	4,637,235
2008	3,859,956	395,529	188,224	65,068	2,335	4,511,112
2009	3,693,915	392,524	192,661	65,643	2,278	4,347,021
2010	3,944,476	402,894	191,105	66,009	2,260	4,606,743
2011	3,818,722	409,088	202,844	66,345	2,203	4,499,203

The following Table 3-23 – Historical kW/kWh Ratio per Applicable Rate Class illustrates the historical ratio of kW/kWh as well as the average ratio for 2000 to 2011. A five-year average ratio is calculated for the Cogeneration rate class.

Table 3-23 – Historical kW/kWh Ratio per Applicable Rate Class

Year	GS>50	Large User	Cogeneration	Street Lighting	Sentinels
Ratio of kW to kWh					
2000	0.2341%	0.1885%	1.0827%	0.2778%	0.2778%
2001	0.2552%	0.1908%	0.8730%	0.3012%	0.2795%
2002	0.2511%	0.1778%	0.9211%	0.2632%	0.2762%
2003	0.2512%	0.1935%	0.6920%	0.2805%	0.2714%
2004	0.2480%	0.1933%	0.7255%	0.2797%	0.2712%
2005	0.2467%	0.1891%	0.6599%	0.2829%	0.2715%
2006	0.2477%	0.1929%	0.6074%	0.2805%	0.2679%
2007	0.2502%	0.2075%	0.5475%	0.2805%	0.2715%
2008	0.2514%	0.2136%	0.4734%	0.2796%	0.2707%
2009	0.2585%	0.2123%	0.4524%	0.2806%	0.2724%
2010	0.2542%	0.2065%	0.4158%	0.2805%	0.2719%
2011	0.2515%	0.2114%	0.5349%	0.2805%	0.2711%
Average 2000 to 2011	**0.2500%**	**0.1981%**	**0.4848%**	**0.2806%**	**0.2728%**

The average ratio was applied to the weather normalized billed energy forecast in Table 3-21 – Alignment of Non-normal to Weather Normal Forecast to provide the forecast of kW by rate class as shown below. The following Table 3-24 – kW Forecast by Applicable Rate Class outlines the forecast of kW for the applicable rate classes.

Table 3-24 – kW Forecast by Applicable Rate Class

Year	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	Total
Predicted Billed kW						
2012 Normalized Bridge	**3,824,518**	**385,417**	**193,378**	**66,804**	**2,173**	**4,472,289**
2013 Normalized Test	**3,914,575**	**387,522**	**203,466**	**67,255**	**2,130**	**4,574,948**

Table 3-25 – Summary of Forecast provides a summary of the billing determinants by rate class that is used to develop the proposed rates.

Table 3-25 – Summary of Forecast

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normalized Bridge	2013 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		3,315,882,997	3,428,161,401	3,408,628,157		
Predicted kWh Purchases		3,321,106,249	3,420,281,434	3,408,068,338	3,425,731,855	3,469,217,216
% Difference of actual and predicted purchases		0.2%	(0.2%)	(0.0%)		
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	131,936	129,058	134,971	134,465	136,223	138,004
kWh	1,091,392,572	1,067,772,436	1,146,523,466	1,128,904,736	1,093,900,394	1,081,449,144
GS<50						
Customers	12,349	11,762	12,116	11,941	11,955	11,970
kWh	422,161,110	392,520,439	407,650,011	408,115,902	396,446,167	392,909,717
GS>50						
Customers	1,595	1,601	1,644	1,620	1,641	1,662
kWh	1,651,046,316	1,429,152,233	1,551,605,457	1,518,546,599	1,529,881,851	1,565,906,059
kW	4,093,815	3,693,915	3,944,476	3,818,722	3,824,518	3,914,575
Large User						
Customers	3	3	3	3	3	3
kWh	200,485,379	184,904,626	195,126,020	193,549,148	194,563,634	195,626,331
kW	383,763	392,524	402,894	409,088	385,417	387,522
Cogeneration						
Connections	3	3	3	3	3	3
kWh	36,489,491	42,590,885	45,965,216	37,918,668	39,888,115	41,969,054
kW	198,649	192,661	191,105	202,844	193,378	203,466
Street Lighting						
Connections	34,187	33,500	33,751	34,061	34,530	35,004
kWh	23,921,899	23,394,430	23,532,529	23,650,724	23,805,271	23,966,083
kW	67,170	65,643	66,009	66,345	66,804	67,255
Sentinels						
Connections	734	730	727	707	694	681
kWh	856,841	836,233	831,089	812,572	796,502	780,921
kW	2,342	2,278	2,260	2,203	2,173	2,130
USL						
Connections	1,581	1,521	1,484	1,557	1,550	1,544
kWh	5,326,529	5,569,256	5,524,132	5,645,414	5,309,579	4,994,818
Total of Above						
Customer/Connections	182,388	178,177	184,699	184,357	186,599	188,871
kWh	3,431,680,138	3,146,740,539	3,376,757,921	3,317,143,763	3,284,591,514	3,307,602,128
kW from applicable classes	4,745,740	4,347,021	4,606,743	4,499,203	4,472,289	4,574,948

OTHER REVENUES

Introduction:

Other revenue relates to all utility revenues other than the distribution and costs of power revenues. London Hydro classifies other revenues into the following categories, which reflect the same categories used in London Hydro's 2009 cost of service application:

- Late Payment Charges,
- Specific Service Charges,
- Retailer Service Charges,
- Other Regulated Revenue, and
- Interest Revenue

This Exhibit will reflect the revenue associated with each category or sub-category from years 2009 (last rebasing year) to 2013 (Test Year). Variances by each sub-category of other revenue are provided.

Late Payment Charges:

London Hydro proposes to continue to charge 1.5 percent per month (19.56 percent annually) for late payments. This would be applied to all accounts not paid by the due date. Bills are due and payable sixteen days from the mailing date, plus grace days to allow for mailing and payment processing delays. A late payment charge ("LPC") is levied on any bill, excluding final bills, with no minimum set. The charge is based on the average daily balance outstanding including all charges, except deposits outstanding between the late payment due date and the LPC processing date.

Specific Service Charges:

London Hydro charges user fees for certain services. Some of these services are provided at the customer's request, such as setting up an account. Others result from London Hydro's business operations, such as collection fees resulting from non-payment of a customer bill. London Hydro does not propose any changes to these specific service charges.

A number of London Hydro's specific service charges, designed to recover the costs of providing these services, are described in the following sections.

Arrears Certificates:

This is a charge levied to research and issue a certificate of arrears per service address. This is typically provided to lawyers during a property purchase.

Collection Charges:

A charge is levied to cover the additional costs for hand-delivering a disconnection notice to customers who have excessive payment arrears.

Reconnection Charges:

A charge is levied to cover the additional costs of reconnecting a customer following a disconnection for arrears reasons. Different amounts are charged based on whether the reconnection is done at the pole or at the meter and if the reconnection is completed during regular hours or after regular hours.

Account Setup Charge:

When a customer establishes a new account, a charge is applied to their first bill to cover the cost of setting up the new account.

Temporary Service Install and Remove Overhead – No Transformer:

This is a charge for temporarily disconnecting then reconnecting electrical service so that construction or maintenance can be completed.

Credit Reference / Credit Check:

Customers opening an account may qualify for a waiver on a security deposit based on a satisfactory credit check. This credit check is done at the customer's expense.

Returned Payment Charge:

This charge is applied to a customer's account for each payment that cannot be processed.

Request for Other Billing Information:

This charge is applied to a customer's account to provide additional information such as a letter of reference or income tax letter.

Standby Charge:

Standby charges are rates paid by customers to receive power from the grid only at times when their distributed generation system is unavailable (during routine maintenance, unplanned outages or supplemental power requirements).

Meter Test Charge:

Customers who believe that their meter is reading incorrectly may request meter verification by Measurement Canada. This charge is applied to a customer's account if the Measurement Canada report indicates that the meter was reading correctly.

Manual Interval Data Collection Charge:

This charge is applied to a customer with an interval meter when the meter read cannot be completed over the phone line, which may not be in working order or is not properly installed. It is the customer's responsibility to maintain these phone lines.

Retail Service Charges:

Retail Service Charges include a standard charge, a monthly fixed charge, a monthly variable charge, a standard distributor consolidated billing charge, a request fee and a processing fee. Each is described in the following sections. In addition, further detail is provided below, and in Appendix 3B.

Standard Charge:

This is a one-time charge, per retailer, to establish the service agreement between the distributor and the retailer.

Monthly Fixed Charge:

This is a flat monthly charge billed to each active energy retailer account.

Monthly Variable Charge:

This is a variable monthly charge to each active energy retailer for each of their customers.

Standard Distributor Consolidated Billing Charge:

This is a variable monthly charge to each active energy retailer for each of their customers.

Request Fee:

This is a fee for each customer request, and it is applied to the requesting party's account.

Processing Fee:

A processing fee per request is applied to the requesting party's account.

Other Regulated Revenue:

Other Regulated Revenue includes Standard Supply Service ("SSS") administration charges, discounts earned on payments terms, leasing substation land, customer contributions, proceeds from sale of scrap, stale-dated cheque write-off, and other miscellaneous services revenue. Each of these is discussed in more detail below.

SSS Administration Charge:

London Hydro proposes to continue the charge of $0.25 per customer per month for all customers that receive their electricity commodity from the default, or standard supply service. Appendix 3B provides detail on the revenues recovered through the application of the SSS Administration Charge from 2009 through 2013.

microFIT Charge:

London Hydro currently applies a fixed monthly charge of $5.25 per month to the microFIT generator rate class for the administrative costs associated with supporting microFIT initiatives. The rate is an OEB-approved province-wide charge, which became effective September 21, 2009, and reflected the Board's determination of the province-wide average cost for all distributors.

London Hydro proposes to adopt the new fixed monthly service charge of $5.40 per month to the microFIT generator rate class to reflect Board updated province-wide review as per proceeding associated with EB-2009-0326 and EB-2010-0219, and the Board's letter, *Update to Fixed Monthly Charge for microFIT Generator Service Classification Board*, of September 20, 2012. The effective date being requested for the new charge is the same as the implementation date of this Application.

Pole Rental:

This is a specific charge for access to London Hydro's power poles by other organizations, such as phone and cable companies.

Discounts Earned on Payment Terms:

London Hydro earns a discount from select suppliers by paying invoices before a specified term date (for example 2%, 10 days, net 30). This amount of income reflects the discount earned from these suppliers.

Proceeds from Sale of Scrap:

London Hydro sells scrap metal and other left over residual materials after the completion of projects.

Stale-Dated Cheque Write-off:

Cheques which have not been cashed by a customer after a two-year period are placed in income by London Hydro. This is primarily related to final billing of customer accounts with a credit balance where the customer cannot be located.

Capital Usage Charge:

These are charges to affiliate companies for the use of assets owned by London Hydro. In London Hydro's case, this refers primarily to administrative building space rental.

Proceeds from Sale of Fixed Assets:

This includes revenues from the sale of retired assets such as vehicles and other equipment.

Interest Revenue:

Interest revenue includes interest on cash and other short-term investments. Interest expense associated with customer deposits, and interest revenue and expense relating to deferral and variance accounts have been excluded for rate-making purposes.

OTHER DISTRIBUTION REVENUE

The following Table 3-26 - Other Distribution Revenues summarizes London Hydro's other revenues, included in total revenue requirement. Discussions of the accounts set out in this summary table follow Table 3-26 - Other Distribution Revenues. It should be noted that revenues in this section are the same under MIFRS as they are under CGAAP.

Table 3-26 - Other Distribution Revenues

OEB No	OEB Account Name	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge CGAAP	2013 Test CGAAP	2012 Bridge MIFRS	2013 Test MIFRS
4080b	Distribution Services Revenue - SSS Admin Fee	350,000	364,022	386,559	393,049	395,000	405,000	395,000	405,000
4080c	MicroFit Fees			410	3,512	5,400	7,900	5,400	7,900
4082	Retail Services Revenues	255,000	226,233	213,910	188,355	175,000	155,000	175,000	155,000
4084	Service Transaction Requests (STR) Revenues	20,000	4,176	12,250	5,910	8,000	8,000	8,000	8,000
4210	Rent from Electric Property	449,500	496,454	498,282	466,557	452,000	466,000	452,000	466,000
4225	Late Payment Charges	1,000,000	997,439	1,197,897	1,072,984	1,100,000	1,133,000	1,100,000	1,133,000
4235	Miscellaneous Service Revenues	847,800	796,561	828,825	820,197	813,000	839,000	813,000	839,000
4235	Miscellaneous Service Revenues (recorded as credits in 5330 expenses)	550,000	493,985	661,368	672,100	648,000	667,000	648,000	667,000
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	3,000	4,237	3,142	3,031	3,586	2,763	3,586	2,763
4355	Gain on Disposition of Utility and Other Property	98,600	98,071	208,665	160,755	129,000	128,000	129,000	128,000
4390	Miscellaneous Non-Operating Income	259,500	197,112	211,138	371,811	249,252	216,575	249,252	216,575
4405	Interest and Dividend Income	460,000	171,194	93,068	105,133	78,551	100,744	78,551	100,744
	TOTAL	4,293,400	3,849,484	4,315,513	4,263,394	4,056,789	4,128,982	4,056,789	4,128,982
Less:	amounts recorded in account 5330 as credits to expense	(550,000)	(493,985)	(661,368)	(672,100)	(648,000)	(667,000)	(648,000)	(667,000)
Less:	50% of Gain on Disposition of Utility Property	(49,300)	(49,035)	(104,332)	(80,377)	(64,500)	(64,000)	(64,500)	(64,000)
	TOTAL REVENUE OFFSETS	3,694,100	3,306,464	3,549,813	3,510,917	3,344,289	3,397,982	3,344,289	3,397,982
OTHER DISTRIBUTION REVENUE									
	Late Payment Charges	1,000,000	997,439	1,197,897	1,072,984	1,100,000	1,133,000	1,100,000	1,133,000
	Specific Service Charges	847,800	796,561	828,825	820,197	813,000	839,000	813,000	839,000
	Other Distribution Revenue	1,846,300	1,512,464	1,523,091	1,617,736	1,431,289	1,425,982	1,431,289	1,425,982
		3,694,100	3,306,464	3,549,813	3,510,917	3,344,289	3,397,982	3,344,289	3,397,982

4080b - Distribution Services Revenue - SSS Admin Fee

Item	Rate	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge	2013 Test
Volumes (at 12 bills per year)	$ 0.25	1,400,000	1,456,087	1,546,237	1,572,196	1,580,000	1,620,000
Revenues		**$ 350,000**	**$ 364,022**	**$ 386,559**	**$ 393,049**	**$ 395,000**	**$ 405,000**
Year-over-year Variance				**$ 22,537**	**$ 6,490**	**$ 1,951**	**$ 10,000**

The revenues in this account are comprised of the monthly regulated Standard Supply Service administration charge that is billed to customers who have elected to receive default energy supply from London Hydro. The monthly charge is $0.25 per customer and monthly and yearly revenues are driven by the number of customers receiving default supply energy. The projected increase for 2013 is due strictly to the quantity of SSS customers. Between 2010 and 2011, there was a 1.7% increase in the volume of SSS customers, and a 3% increase over 2011 actuals for the 2013 Test Year is projected.

4080c - Distribution Services Revenue - microFIT Fee

Item	Rate	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge	2013 Test
Number of accounts	$ 5.25			7	56	86	
	$ 5.40						122
Revenues				**$ 410**	**$ 3,512**	**$ 5,400**	**$ 7,900**
Year-over-year Variance				**$ 410**	**$ 3,102**	**$ 1,888**	**$ 2,500**

Revenues from microFIT fees are driven by the number of microFIT generation facilities contracted under the OPA's microFIT program and connected to London Hydro's distribution system. A fixed monthly OEB-approved province-wide charge of $5.25 per month applied to the 2012 Bridge Year and $5.40 per month applied to the 2013 Test Year. The number of microFIT Generation facilities is expected to increase in London.

4082 - Retail Services Revenue

Item	Rate	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Volumes							
Retail contract initiation charge - one time charge	$ 100.00	4	2	3	3	2	2
Retailer monthly fixed charge for contract administration	$ 20.00	140	212	197	241	183	162
Retailer monthly customer administration charge	$ 0.50	318,698	295,550	267,362	231,333	220,760	195,530
Distributor consolidated billing charge - per month per customer	$ 0.30	309,024	250,620	266,882	233,237	209,634	185,675
Retailer consolidated billing credit - per month per customer	$ (0.30)	706	3,946	13,469	7,899	7,137	6,321
Revenues		**$ 255,000**	**$ 226,233**	**$ 213,910**	**$ 188,355**	**$ 175,000**	**$ 155,000**
Retail contract initiation charge - one time charge		356	208	273	261	209	185
Retailer monthly fixed charge for contract administration		2,800	4,248	3,932	4,826	3,662	3,243
Retailer monthly customer administration charge		159,349	147,775	133,681	115,667	110,380	97,765
Distributor consolidated billing charge - per month per customer		92,707	75,186	80,065	69,971	62,890	55,703
Retailer consolidated billing credit - per month per customer		(212)	(1,184)	(4,041)	(2,370)	(2,141)	(1,896)
Year-over-year Variance				**$ (12,323)**	**$ (25,555)**	**$ (13,355)**	**$ (20,000)**

The revenues in this account are comprised of the monthly regulated service fees that are chargeable to retailers and their customers for the provision of retailer contract maintenance and consolidated billing services. Revenue volumes in this account are driven by the monthly number of retailer customers and number of retailers. Although the number of retailers and the number of retailer associated customers change continuously, the following values indicate the annual trends for the following periods:

- December 31, 2009: 13 retailers, 22,768 retailer customers
- December 31, 2010: 14 retailers, 21,112 retailer customers
- December 31, 2011: 16 retailers, 16,217 retailer customers
- June 30, 2012: 16 retailers, 14,033 retailer customers

The 2012 and 2013 forecast revenues of $175,000 and $155,000 respectively are 7% and 18% lower than the 2011 actual amount of $188,355 and reflect the fact that the number of retailer customers has been steadily decreasing since 2009, and was reduced by 23% over the course of fiscal year 2011.

4084 - Service Transaction Requests - STR Revenues

Item	Rate	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Volumes							
Request fee - per request	\$ 0.25	32,000	7,256	21,136	10,064	13,624	13,624
Processing fee - per request	\$ 0.50	24,000	4,725	13,932	6,787	9,188	9,188
Revenues		**\$ 20,000**	**\$ 4,176**	**\$ 12,250**	**\$ 5,910**	**\$ 8,000**	**\$ 8,000**
Request fee - per request		8,000	1,814	5,284	2,516	3,406	3,406
Processing fee - per request		12,000	2,362	6,966	3,394	4,594	4,594
Year-over-year Variance				**\$ 8,074**	**\$ (6,341)**	**\$ 2,091**	**\$ -**

The revenues in this account are comprised of the regulated service transaction ("STR") "request" and "processing" fees that are chargeable to retailers for additions, removals or modifications to their customer records. Annual revenue volumes are driven by the level of activity associated with customer movements to or from retailers. The fluctuation in revenues stems primarily from the fact that service transactions are customer driven and can be influenced by factors such as consumer awareness and retailer marketing in the area. Most retailer contracts are 3 or 5 year terms, and therefore expiry and renewal transactions would surge periodically and not display an annual trend.

4210 - Rent from Electric Property

Item	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Rates						
Pole rentals - per pole per year	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35
Volumes						
Pole rentals - poles	15,952	16,138	16,203	16,123	16,689	17,271
Administrative Building Space Rental - average floor space rented	6,656	11,350	11,406	8,472	5,788	5,788
Revenues	**$ 449,500**	**$ 496,454**	**$ 498,282**	**$ 466,557**	**$ 452,000**	**$ 466,000**
Pole rentals	356,500	360,688	362,130	360,346	373,000	386,000
Administrative Building Space Rental	69,000	117,655	118,237	87,827	60,000	60,000
Duct rentals and miscellaneous	24,000	18,110	17,915	18,384	19,000	20,000
Year-over-year Variance			**$ 1,828**	**$ (31,725)**	**$ (14,557)**	**$ 14,000**

Rent from electric property is composed of the OEB-approved rate of $22.35 per pole per year for access to power poles primarily by telephone and cable service providers, plus costs recovered for rental of unused or excess administrative building space.

The Administrative Building Space Rental refers to space within the London Hydro Administrative Building that was rented out to the City of London until 2011. The City of London has vacated this space, and the OPA programs are now renting the space since the beginning of 2011.

The amount of Rent from Electric Property reported in the 2011 Trial Balance was $60,000 less than what is shown here due to this amount relating to OPA rent being classified as an OM&A cost recovery instead of other revenue. In all other years administrative rentals appear in account 4210, accordingly this chart has been adjusted for comparability purposes, with a corresponding increase in OM&A expenses to result in a net effect of zero.

4225 - Late Payment Charges

Item	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Revenues	**$ 1,000,000**	**$ 997,439**	**$ 1,197,897**	**$ 1,072,984**	**$ 1,100,000**	**$ 1,133,000**
Late payment charges on overdue accounts - 1.5% per month	1,000,000	997,439	1,197,897	1,072,984	1,100,000	1,133,000
Year-over-year Variance			**$ 200,457**	**$ (124,913)**	**$ 27,016**	**$ 33,000**

The 2009 Actuals show a small decrease from the Board Approved amount, which directly relates to the implementation of the new SAP Customer Information and Billing System (SAP). SAP went live in mid-2009 and resulted in many complications that affected billing and accounts receivable. Due to this fact, London Hydro stopped billing late payment charges for a short period of time.

The increase in 2010 Actuals is economy driven – because of the economic downturn in this year, customers were paying bills later than normal and London Hydro was generating revenue on these overdue accounts. This trend seems to have normalized itself in 2011.

4235 - Miscellaneous Service Revenues

Item	Rate	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Volumes							
Interval Metering Charges	$ 5.50	6,600	6,370	6,805	6,673	6,727	6,727
Occupancy Charges	$ 30.00	22,500	19,371	21,423	21,251	21,833	22,500
Arrears Certificates	$ 16.00	2,688	1,926	1,485	1,654	1,625	1,625
Temporary service - install and remove overhead no transformer	$ 500.00	38	33	36	30	24	25
Temporary service - install and remove underground no transformer	$ 300.00	20	9	11	13	8	8
Revenues		**$ 847,800**	**$ 796,561**	**$ 828,825**	**$ 820,197**	**$ 813,000**	**$ 839,000**
Interval Metering Charges		36,300	35,037	37,426	36,699	37,000	37,000
Occupancy Charges		675,000	581,128	642,693	637,543	655,000	675,000
Arrears Certificates		43,000	30,810	23,766	26,470	26,000	26,000
Electric Service Calls		5,000	2,439	-	-	-	-
Temporary service - install and remove overhead no transformer		19,000	16,286	18,000	15,000	11,982	12,420
Temporary service - install and remove underground no transformer		6,000	2,571	3,300	3,900	2,386	2,473
Temporary service - install and remove - non standard		61,500	122,362	71,225	97,832	67,632	70,107
Miscellaneous Customer Service Charges		2,000	3,393	7,099	7,901	8,000	8,000
Billable Services			2,534	25,316	(5,148)	5,000	8,000
Year-over-year Variance				**$ 32,264**	**$ (8,628)**	**$ (7,197)**	**$ 26,000**

The 2009 Actual revenues from occupancy charges were $93,872 or 14% lower than the 2009 Board Approved due to lower volumes. Similarly, arrears certificates were $12,190 or 28% lower, when compared 2009 Board Approved to Actuals.

Revenue from Billable Services relates to cost recoveries associated with work performed by London Hydro for third parties. This revenue is driven purely by demand and does not follow any particular trend.

Total revenue values for 2012 and 2013 reflect normalized volumes and revenue amounts.

5330 - Collection Charges (4235)

Item	Rate	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Volumes							
Easement letters	$ 15.00	60	-	-	-	-	-
Returned cheque charges	$ 15.00	2,300	2,134	1,549	1,340	1,870	1,924
Collection of account charge - no disconnection	$ 10.00	38,100	36,445	48,768	47,898	47,257	48,643
Disconnect/reconnect at meter - during regular hours	$ 35.00	3,820	2,786	4,299	4,943	4,211	4,334
Revenues		**$ 550,000**	**$ 493,985**	**$ 661,368**	**$ 672,100**	**$ 648,000**	**$ 667,000**
Easement letters		900	-	-	-	-	-
Returned cheque charges		34,500	32,009	23,234	20,102	28,045	28,867
Collection of account charge - no disconnection		381,000	364,453	487,679	478,980	472,570	486,426
Disconnect/reconnect at meter - during regular hours		133,600	97,523	150,454	173,018	147,385	151,707
Year-over-year Variance				**$ 167,383**	**$ 10,732**	**$ (24,100)**	**$ 19,000**

The above charges have been recorded as credits to account 5330 “collection charges” and reported as a credit to “billing and collecting” costs. This accounting treatment is based on the direction provided in the Board’s Accounting Procedures Handbook, which states that Account 5330 “shall include all amounts recovered due to the imposition of charges related to the collection of customer accounts”.

It is London Hydro’s interpretation that the collection of account charge and the disconnect/reconnect at meter charge are “amounts recovered due the imposition of charges related to the collection of customer accounts.”

Whether these amounts are treated as other income or credits to billing and collection costs, has no effect on the total revenue requirement.

The revenue amounts forecasted for 2012 Bridget Year and 2013 Test Year reflect normal levels of activity based on historical results.

4330 - Costs and Expenses of Merchandising, Jobbing, Etc.

Item	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Net income (expense) from merchandising, jobbing, etc.	$ 3,000	$ 4,237	$ 3,142	$ 3,031	$ 3,586	$ 2,763
Year-over-year Variance			$ (1,095)	$ (111)	$ 555	$ (823)

This account reflects the net revenues and expenses of electrical meter sealing and servicing activities performed by London Hydro's Electric Meter Department for third parties.

4355 - Gain on Disposition of Utility and Other Property

Item	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Gain on disposal of utility and other property	$ 98,600	$ 98,071	$ 208,665	$ 160,755	$ 129,000	$ 128,000
Less: 50% of gain deducted for revenue offset calculation	(49,300)	(49,035)	(104,332)	(80,377)	(64,500)	(64,000)
	49,300	49,035	104,332	80,377	64,500	64,000
Year-over-year Variance			$ 55,297	$ (23,955)	$ (15,877)	$ (500)

Gain on disposal of utility and other property reflects the gain on sale of scrap transformers which is expected to be $95,000 in 2013 Test Year, plus the gain on sale of vehicles of $33,000. There are 12 vehicles budgeted for disposal/replacement in 2013 Test Year. This account also includes any gain or loss on the disposition of substation equipment, although there are none budgeted for 2013 Test Year. The gain on disposal has been reduced by 50% for offset calculation purposes, as provided in the May 11, 2005 Report of the Board on the 2006 Electricity Distribution Rate Handbook (RP-2004-0188) at page 28.

The gain realized in 2010 was unusually high and not indicative of any trend. In this year, London Hydro did very well on vehicle auctions (especially backhoes) and scrap transformer proceeds were also unusually high. However, it must be noted that these high sales are atypical.

4390 - Miscellaneous Non-Operating Income

Item	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Revenues	**$ 259,500**	**$ 197,112**	**$ 211,138**	**$ 371,811**	**$ 249,252**	**$ 216,575**
Supplier Discounts - on material purchases	30,000	23,371	32,755	25,674	29,000	31,000
Supplier Penalties - re: material purchase agreements	500	5,238	1,543	8,574	4,000	4,000
Sale of Scrap	175,000	119,871	170,480	311,357	150,000	150,000
Fitness Centre Revenue	3,000	3,150	2,599	2,100	3,000	3,000
Miscellaneous Revenue	11,000	20,394	3,566	5,008	6,000	6,000
Non Refundable Customer Credits	40,000	25,088	(250)	(143)	-	-
Management Fee for Renewable Energy Non-Distribution Asset			444	19,241	57,252	22,575
Year-over-year Variance			**$ 14,026**	**$ 160,673**	**$ (122,559)**	**$ (32,677)**

Miscellaneous non-operating revenues by their nature are difficult to accurately forecast.

2013 Projections are based on a review of recent historical patterns.

The variance in non-refundable customer credits is related to the usage of customer account credit balances, which occurs in situations where, for example, a customer has moved out and cannot be located. In previous years, this type of write-off was captured in miscellaneous non-operating income and recognized into income directly. With the implementation of SAP in mid-2009, the procedure was changed, and these credits are now included as a direct offset to the bad debt expense. This change in where these credits are recognized results in a significant variance at the account level, however, this has no impact on revenue requirement.

Sale of scrap was particularly high in 2011 and not indicative of a normal trend. This was due to significantly higher volumes of scrap removed from subdivisions compared to the previous year. This included three times the volume of scrap lead covered cable and ten times the volume of scrap bare copper wire when compared with 2010. As well, the daily average price was higher in 2011 for lead covered copper than in 2010.

Miscellaneous revenue contains items such as tree planting revenue, monthly administration charge to the OEFC and government rebates.

The management fees associated with the ongoing administration and management of the renewable non-distribution assets are included in miscellaneous non-operating income. More details are available in Exhibit 1 in the section titled: Non-Distribution Activities.

4405 - Interest Income

Item	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Revenues	**$ 460,000**	**$ 171,194**	**$ 93,068**	**$ 105,132**	**$ 78,551**	**$ 100,744**
Short term Investment Interest	85,000	8,117	-	-	-	-
Bank Deposit Interest	365,000	145,871	92,924	100,072	50,000	50,000
Employee Purchase Interest	-	260	374	273	-	-
Miscellaneous Interest Revenue	-	13,395	3,903	(1,067)	-	-
Sundry A/R Interest	10,000	3,551	(4,190)	(0)	-	-
Interest on Investment of Non-Distribution Renewable Generation Asset			57	5,855	28,551	50,744
Year-over-year Variance			**$ (78,126)**	**$ 12,064**	**$ (26,581)**	**$ 22,193**

Interest income is derived from investment of surplus funds.

Interest associated with Retail Settlement Variance Accounts ("RSVAs") and other deferral and variance accounts are not included in Account 4405 Interest Income in this Application. This interest is included in the appropriate Deferral and Variance Accounts in Exhibit 9, and the offset was reported in the 2011 RRR Trial Balance in Account 4405 Interest Income.

The 2009 Actual revenue of $171,194 was $288,806 less than the 2009 Board Approved amount. This variance results from the reduction of short-term investment interest and bank deposit interest related to surplus funds.

After 2009, London Hydro did not hold any short-term investments which resulted in a large variance.

Bank deposit interest in 2012 and 2013 is projected to be lower than previous levels due to a projected reduction in average monthly bank balances.

The interest on funds provided for the capital expenditures for the non-distribution renewable generation operations at market based rates is included in interest income as discussed in Exhibit 1 in the section titled: Non-Distribution Activities.

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Appendix 3A

Monthly Data used in Regression Analysis

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	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Number of Customers	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-96	272,709,712	775	0	94.72	31	0	120,586	0	352	264,730,822
Feb-96	250,721,520	687	0	94.80	29	0	120,626	0	336	247,443,989
Mar-96	254,045,186	663	0	94.89	31	1	120,683	0	336	248,966,883
Apr-96	226,155,802	398	0	94.97	30	1	120,723	0	336	228,999,824
May-96	224,163,757	202	14	95.06	31	1	120,743	0	352	233,637,791
Jun-96	240,563,976	21	46	95.14	30	0	120,913	0	320	242,973,910
Jul-96	252,020,632	14	53	95.23	31	0	121,023	0	352	254,746,342
Aug-96	262,477,292	4	57	95.32	31	0	121,168	0	336	255,486,011
Sep-96	230,719,909	86	18	95.40	30	1	121,169	0	320	222,111,921
Oct-96	225,749,274	265	0	95.49	31	1	121,165	0	352	229,283,475
Nov-96	239,278,482	524	0	95.57	30	1	121,263	0	320	235,423,057
Dec-96	249,752,064	590	0	95.66	31	0	121,376	0	320	253,689,668
Jan-97	270,958,014	751	0	96.01	31	0	121,451	0	352	264,990,460
Feb-97	233,638,303	597	0	96.37	28	0	121,537	0	320	237,544,991
Mar-97	245,984,229	562	0	96.73	31	1	121,572	0	304	243,398,798
Apr-97	226,586,927	388	0	97.08	30	1	121,687	0	352	232,003,084
May-97	221,777,931	284	0	97.44	31	1	121,795	0	336	231,420,261
Jun-97	245,909,984	30	57	97.81	30	0	121,923	0	336	254,318,890
Jul-97	266,655,250	14	75	98.17	31	0	122,040	0	352	270,710,979
Aug-97	244,532,760	30	30	98.53	31	0	122,151	0	320	243,846,598
Sep-97	230,908,290	87	8	98.90	30	1	122,331	0	336	221,537,819
Oct-97	233,469,355	271	5	99.26	31	1	122,354	0	352	236,903,135
Nov-97	238,941,984	488	0	99.63	30	1	122,538	0	304	236,988,674
Dec-97	254,526,474	606	0	100.00	31	0	122,645	0	336	260,555,336
Jan-98	258,410,931	614	0	100.39	31	0	122,929	0	336	261,479,069
Feb-98	228,720,522	516	0	100.79	28	0	123,021	0	320	238,178,633
Mar-98	248,917,882	506	2	101.18	31	1	123,015	0	352	249,804,162
Apr-98	222,052,650	301	0	101.58	30	1	123,138	0	336	231,301,114
May-98	242,114,631	60	26	101.98	31	1	123,245	0	320	238,144,714
Jun-98	263,628,049	62	82	102.38	30	0	123,401	0	352	276,424,077
Jul-98	278,603,858	0	81	102.78	31	0	123,419	0	352	278,890,173
Aug-98	283,694,537	7	100	103.18	31	0	123,530	0	320	288,637,044
Sep-98	248,590,718	46	45	103.59	30	1	123,585	0	336	246,024,431
Oct-98	231,445,560	231	0	104.00	31	1	123,765	0	336	236,031,879
Nov-98	245,997,258	402	0	104.40	30	1	123,864	0	336	239,942,399
Dec-98	263,201,304	541	0	104.81	31	0	123,931	0	336	262,557,724
Jan-99	290,074,203	770	0	105.45	31	0	127,166	0	320	274,853,663
Feb-99	249,331,391	550	0	106.09	28	0	127,712	0	320	246,461,397
Mar-99	271,758,261	588	0	106.73	31	1	127,756	0	368	261,039,699
Apr-99	238,110,801	301	0	107.38	30	1	127,806	0	336	238,246,893
May-99	245,365,517	105	13	108.03	31	1	127,931	0	320	240,663,074
Jun-99	290,867,112	40	85	108.68	30	0	128,081	0	352	284,683,410
Jul-99	322,910,378	2	156	109.34	31	0	128,110	0	336	328,675,709
Aug-99	274,982,939	13	44	110.00	31	0	128,241	0	336	265,694,382
Sep-99	256,937,747	67	37	110.67	30	1	128,142	0	336	250,442,356
Oct-99	245,349,341	287	0	111.34	31	1	128,473	0	320	246,575,816
Nov-99	253,739,065	380	0	112.01	30	1	128,689	0	352	248,805,263
Dec-99	275,064,492	599	0	112.69	31	0	128,789	0	336	274,904,900
Jan-00	285,344,523	746	0	113.21	31	0	128,886	0	320	282,300,663
Feb-00	262,358,155	611	0	113.73	29	0	128,987	0	336	265,187,820
Mar-00	261,511,431	422	0	114.25	31	1	129,094	0	368	260,478,386
Apr-00	240,148,602	338	0	114.77	30	1	129,186	0	304	246,340,260
May-00	252,573,968	138	19	115.30	31	1	129,288	0	352	256,061,956
Jun-00	273,561,877	31	47	115.83	30	0	129,391	0	352	270,133,064
Jul-00	278,427,567	16	53	116.36	31	0	129,493	0	320	276,871,956
Aug-00	287,446,139	23	61	116.90	31	0	126,988	0	352	284,518,448
Sep-00	262,882,455	120	32	117.43	30	1	127,222	0	320	256,771,453
Oct-00	252,488,338	222	1	117.97	31	1	128,605	0	336	251,992,916
Nov-00	262,713,617	449	0	118.52	30	1	129,232	0	352	259,790,255
Dec-00	291,842,465	815	0	119.06	31	0	129,379	0	304	291,428,278

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Number of Customers	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-01	292,017,932	712	0	119.23	31	0	129,514	0	352	289,406,586
Feb-01	259,661,392	602	0	119.40	28	0	129,478	0	320	264,090,898
Mar-01	276,989,730	569	0	119.58	31	1	129,359	0	352	273,204,843
Apr-01	243,123,989	298	0	119.75	30	1	129,425	0	320	250,744,849
May-01	250,362,097	127	4	119.92	31	1	129,031	0	352	252,007,746
Jun-01	285,172,728	39	63	120.10	30	0	128,993	0	336	283,102,542
Jul-01	296,380,891	17	84	120.27	31	0	129,376	0	336	300,514,867
Aug-01	315,765,517	1	111	120.45	31	0	130,778	0	352	316,716,338
Sep-01	258,838,258	102	19	120.62	30	1	130,348	0	304	251,262,263
Oct-01	257,786,957	248	1	120.80	31	1	131,383	0	352	257,761,122
Nov-01	257,291,585	331	0	120.97	30	1	132,876	0	352	256,551,970
Dec-01	273,387,719	544	0	121.15	31	0	133,590	0	304	279,636,756
Jan-02	284,956,292	598	0	121.50	31	0	132,328	0	352	286,053,122
Feb-02	257,104,053	560	0	121.86	28	0	131,770	0	320	264,830,042
Mar-02	275,736,546	549	0	122.22	31	1	131,379	0	320	273,079,059
Apr-02	258,757,607	331	6	122.59	30	1	131,267	0	352	261,351,733
May-02	256,339,016	252	6	122.95	31	1	71,686	0	352	256,257,494
Jun-02	288,223,672	37	73	123.31	30	0	120,852	0	320	290,399,191
Jul-02	340,455,042	1	150	123.68	31	0	144,775	0	352	344,203,756
Aug-02	318,581,949	3	97	124.04	31	0	129,719	0	336	311,336,571
Sep-02	288,324,578	69	73	124.41	30	1	128,978	0	320	285,247,221
Oct-02	266,549,588	628	14	124.78	31	1	140,159	0	352	291,384,898
Nov-02	270,818,727	455	0	125.14	30	1	124,982	0	336	265,757,288
Dec-02	290,667,590	663	0	125.51	31	0	125,012	0	320	290,889,935
Jan-03	308,746,406	824	0	125.66	31	0	148,934	0	352	304,900,062
Feb-03	277,430,014	713	0	125.81	28	0	121,367	0	320	276,149,400
Mar-03	285,335,367	596	0	125.95	31	1	143,319	0	336	282,282,894
Apr-03	257,349,287	371	2	126.10	30	1	122,612	0	336	262,825,498
May-03	254,818,779	185	0	126.24	31	1	137,843	0	336	259,731,528
Jun-03	269,101,702	48	34	126.39	30	0	125,384	0	336	273,699,112
Jul-03	305,967,621	3	75	126.54	31	0	149,589	0	352	304,977,668
Aug-03	296,069,115	8	94	126.68	31	0	125,737	0	320	310,845,399
Sep-03	264,521,280	76	16	126.83	30	1	138,449	0	336	257,880,898
Oct-03	264,288,530	293	1	126.98	31	1	138,100	0	352	267,775,600
Nov-03	267,235,972	388	0	127.12	30	1	123,180	0	320	262,952,331
Dec-03	288,417,091	585	0	127.27	31	0	139,377	0	336	291,500,152
Jan-04	312,963,781	854	0	127.53	31	0	139,157	0	336	306,263,446
Feb-04	282,465,406	657	0	127.80	29	0	123,044	0	320	281,304,340
Mar-04	288,116,509	498	0	128.06	31	1	151,199	0	368	282,512,030
Apr-04	256,878,634	326	0	128.32	30	1	131,703	0	336	263,105,161
May-04	261,669,749	155	11	128.59	31	1	128,252	0	320	264,835,838
Jun-04	272,455,233	55	27	128.85	30	0	144,202	0	352	276,260,108
Jul-04	298,190,271	7	70	129.12	31	0	136,330	0	336	302,260,716
Aug-04	287,764,777	32	38	129.38	31	0	140,482	0	336	286,069,385
Sep-04	283,456,771	53	25	129.65	30	1	132,896	0	336	264,206,047
Oct-04	264,960,641	234	0	129.92	31	1	132,729	0	320	264,655,932
Nov-04	272,879,194	400	0	130.19	30	1	140,668	0	352	271,344,489
Dec-04	302,428,639	656	0	130.45	31	0	133,035	0	336	298,047,159
Jan-05	312,992,589	776	0	130.74	31	0	144,835	0	320	305,153,007
Feb-05	275,760,394	651	0	131.03	28	0	121,012	0	320	278,482,270
Mar-05	293,348,959	645	0	131.33	31	1	145,472	0	352	292,197,478
Apr-05	260,460,308	310	0	131.62	30	1	137,293	0	336	266,583,553
May-05	258,793,088	199	0	131.91	31	1	137,609	0	336	266,679,869
Jun-05	330,466,263	11	121	132.20	30	0	141,453	0	352	331,374,805
Jul-05	343,548,005	2	138	132.50	31	0	134,212	0	320	343,270,927
Aug-05	334,606,169	5	106	132.79	31	0	145,457	0	352	329,364,568
Sep-05	289,174,433	31	35	133.09	30	1	130,865	0	336	272,310,683
Oct-05	275,317,332	228	9	133.38	31	1	142,209	0	320	274,360,079
Nov-05	279,512,943	393	0	133.68	30	1	138,518	0	352	274,545,476
Dec-05	305,576,475	702	0	133.98	31	0	130,625	0	320	302,987,450

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Number of Customers	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-06	298,877,072	555	0	134.25	31	0	150,637	130,806	336	298,641,598
Feb-06	278,231,468	609	0	134.53	28	0	126,847	261,613	320	280,229,053
Mar-06	292,223,000	546	0	134.81	31	1	150,969	392,419	368	291,620,622
Apr-06	257,433,385	286	0	135.08	30	1	118,484	523,225	304	263,385,282
May-06	274,689,500	152	23	135.36	31	1	156,312	654,031	352	283,136,256
Jun-06	293,283,565	27	44	135.64	30	0	139,580	784,838	352	289,806,639
Jul-06	339,166,295	3	134	135.92	31	0	139,717	915,644	320	343,630,656
Aug-06	317,558,853	5	68	136.20	31	0	143,912	1,046,450	352	308,717,133
Sep-06	266,169,476	99	5	136.48	30	1	132,262	1,177,257	320	259,053,588
Oct-06	275,845,825	308	1	136.76	31	1	147,894	1,308,063	336	276,737,191
Nov-06	277,675,186	383	0	137.04	30	1	136,847	1,438,869	352	274,411,651
Dec-06	292,401,294	512	0	137.33	31	0	128,463	1,569,676	304	291,633,393
Jan-07	305,103,539	656	0	137.55	31	0	156,325	1,609,270	352	306,291,463
Feb-07	294,287,806	759	0	137.78	28	0	128,913	1,648,864	320	289,112,621
Mar-07	292,935,895	527	0	138.01	31	1	148,641	1,688,458	352	289,896,238
Apr-07	264,940,056	371	0	138.23	30	1	137,394	1,728,053	320	272,254,886
May-07	273,298,422	132	23	138.46	31	1	146,093	1,767,647	352	281,671,045
Jun-07	309,675,938	23	70	138.69	30	0	137,690	1,807,241	336	304,302,963
Jul-07	307,009,101	11	72	138.92	31	0	149,174	1,846,835	336	311,824,072
Aug-07	322,676,682	12	89	139.15	31	0	142,203	1,886,429	352	322,314,858
Sep-07	286,198,800	61	35	139.38	30	1	130,729	1,926,024	304	274,607,977
Oct-07	280,838,093	150	22	139.61	31	1	153,843	1,965,618	352	283,738,900
Nov-07	278,969,671	469	0	139.84	30	1	138,781	2,005,212	352	281,101,686
Dec-07	297,804,061	657	0	140.07	31	0	130,409	2,044,806	304	301,695,208
Jan-08	306,586,096	639	0	139.97	31	0	158,586	2,237,100	352	306,971,204
Feb-08	289,527,654	693	0	139.86	29	0	130,831	2,429,393	320	292,146,692
Mar-08	289,956,690	627	0	139.76	31	1	138,791	2,621,687	304	290,675,881
Apr-08	259,621,600	265	0	139.65	30	1	155,005	2,813,980	352	270,136,883
May-08	252,168,944	209	2	139.55	31	1	139,474	3,006,274	336	270,524,396
Jun-08	292,440,383	24	66	139.44	30	0	143,329	3,198,567	336	300,642,596
Jul-08	323,790,279	4	97	139.34	31	0	151,627	3,390,861	352	324,574,332
Aug-08	298,482,481	12	53	139.23	31	0	136,044	3,583,154	320	295,094,364
Sep-08	288,969,236	57	21	139.13	30	1	147,913	3,775,448	336	266,586,154
Oct-08	266,480,668	287	0	139.02	31	1	147,735	3,967,741	352	272,988,985
Nov-08	273,279,526	468	0	138.92	30	1	132,210	4,160,035	304	271,248,228
Dec-08	301,310,919	671	0	138.81	31	0	144,233	4,352,328	336	299,959,266
Jan-09	311,998,202	850	0	138.39	31	0	152,228	4,429,683	336	309,956,421
Feb-09	268,436,813	613	0	137.97	28	0	127,339	4,507,038	304	273,938,927
Mar-09	283,235,896	533	1	137.54	31	1	165,350	4,584,392	352	286,089,994
Apr-09	253,936,982	307	3	137.13	30	1	136,685	4,661,747	320	262,987,958
May-09	254,758,276	157	3	136.71	31	1	135,819	4,739,102	320	259,860,498
Jun-09	267,485,696	50	36	136.29	30	0	92,032	4,816,456	352	272,002,768
Jul-09	279,139,415	20	29	135.87	31	0	185,305	4,893,811	352	283,553,878
Aug-09	305,627,057	18	72	135.46	31	0	169,977	4,971,165	320	303,210,787
Sep-09	268,881,546	71	16	135.05	30	1	140,282	5,048,520	336	256,008,993
Oct-09	263,882,194	301	0	134.63	31	1	144,565	5,125,875	336	264,933,980
Nov-09	262,839,393	357	0	134.22	30	1	143,707	5,203,229	320	260,329,137
Dec-09	295,661,527	637	0	133.81	31	0	115,825	5,280,584	352	288,232,906
Jan-10	305,893,667	733	0	134.14	31	0	160,301	5,311,106	320	296,979,284
Feb-10	272,278,535	633	0	134.47	28	0	142,477	5,341,627	304	271,278,514
Mar-10	274,294,081	450	0	134.81	31	1	168,740	5,372,149	368	277,833,738
Apr-10	247,328,090	236	0	135.14	30	1	144,313	5,402,671	320	254,481,896
May-10	273,772,206	121	35	135.47	31	1	142,174	5,433,193	320	274,190,108
Jun-10	292,784,542	24	58	135.81	30	0	155,898	5,463,715	352	289,232,927
Jul-10	339,386,498	6	130	136.14	31	0	146,680	5,494,236	336	333,727,892
Aug-10	330,803,305	6	122	136.48	31	0	150,892	5,524,758	336	329,958,261
Sep-10	268,756,301	88	24	136.81	30	1	144,054	5,555,280	336	262,948,451
Oct-10	258,965,938	240	0	137.15	31	1	143,518	5,585,802	320	262,133,903
Nov-10	266,735,433	414	0	137.49	30	1	151,037	5,616,323	336	268,106,325
Dec-10	297,162,805	714	0	137.83	31	0	134,765	5,646,845	368	299,410,135

	Purchased	Heating Degree Days	Cooling Degree Days	Ontario Real GDP Monthly %	Number of Days in Month	Spring Fall Flag	Number of Customers	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-11	304,929,971	799	0	138.03	31	0	163,869	5,844,267	336	305,191,866
Feb-11	273,057,173	678	0	138.24	28	0	121,900	6,041,689	304	273,752,092
Mar-11	287,376,110	600	0	138.44	31	1	169,374	6,239,112	368	288,095,013
Apr-11	254,949,996	330	0	138.65	30	1	131,452	6,436,534	320	259,584,384
May-11	263,999,437	126	17	138.86	31	1	151,342	6,633,956	336	267,736,174
Jun-11	283,035,539	27	40	139.06	30	0	139,147	6,831,378	352	277,635,311
Jul-11	346,752,252	0	161	139.27	31	0	168,450	7,028,801	320	353,109,515
Aug-11	316,545,486	2	83	139.48	31	0	156,464	7,226,223	352	308,737,530
Sep-11	274,826,846	72	29	139.69	30	1	145,289	7,423,645	336	264,164,013
Oct-11	261,557,547	235	0	139.89	31	1	148,682	7,621,067	320	261,103,181
Nov-11	260,988,850	348	0	140.10	30	1	148,170	7,818,489	352	263,403,300
Dec-11	280,608,950	548	0	140.31	31	0	132,250	8,015,912	336	285,555,959
Jan-12		728	0	140.52	31	0	135,179	7,799,279	336	296,318,963
Feb-12		633	0	140.73	29	0	138,108	7,582,646	320	279,602,096
Mar-12		555	0	140.94	31	1	141,038	7,366,013	352	281,475,147
Apr-12		322	1	141.15	30	1	143,967	7,149,380	320	262,260,856
May-12		163	12	141.36	31	1	146,896	6,932,747	352	269,396,819
Jun-12		34	59	141.57	30	0	149,825	6,716,114	336	292,588,868
Jul-12		7	97	141.78	31	0	149,977	6,499,481	336	319,535,783
Aug-12		11	77	141.99	31	0	150,128	6,282,848	352	309,650,271
Sep-12		74	27	142.20	30	1	150,279	6,066,215	304	267,447,901
Oct-12		277	3	142.41	31	1	150,431	5,849,582	352	274,277,455
Nov-12		415	0	142.62	30	1	150,582	5,632,950	352	274,864,420
Dec-12		628	0	142.83	31	0	150,733	5,416,317	304	298,313,276
Jan-13		728	0	143.13	31	0	150,885	5,595,538	352	307,017,664
Feb-13		633	0	143.42	28	0	151,036	5,774,759	304	281,209,361
Mar-13		555	0	143.72	31	1	151,188	5,953,981	320	286,636,448
Apr-13		322	1	144.02	30	1	151,339	6,133,202	352	270,744,343
May-13		163	12	144.31	31	1	151,490	6,312,423	352	274,558,751
Jun-13		34	59	144.61	30	0	151,642	6,491,645	320	295,536,917
Jul-13		7	97	144.91	31	0	151,793	6,670,866	352	323,935,347
Aug-13		11	77	145.21	31	0	151,944	6,850,087	336	311,072,301
Sep-13		74	27	145.50	30	1	152,096	7,029,309	320	270,322,108
Oct-13		277	3	145.80	31	1	152,247	7,208,530	352	275,282,134
Nov-13		415	0	146.10	30	1	152,398	7,387,751	336	273,999,906
Dec-13		628	0	146.41	31	0	152,550	7,566,973	320	298,901,936

Appendix 3B

Other Operating Revenue Presented in
OEB Chapter 2 Filing Requirements Schedule "Appendix 2F"
by Uniform System of Accounts

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Appendix 2-F
Other Operating Revenue

USoA #	USoA Description	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year³	Bridge Year³	Test Year
						2012	2012	2013
	Reporting Basis			CGAAP		CGAAP	MIFRS	MIFRS
4235	Specific Service Charges	$ 796,561	$ 828,825	$ 820,197		$ 813,000	$ 813,000	$ 839,000
4225	Late Payment Charges	$ 997,439	$ 1,197,897	$ 1,072,984		$ 1,100,000	$ 1,100,000	$ 1,133,000
4082	Retail Services Revenues	$ 226,233	$ 213,910	$ 188,355		$ 175,000	$ 175,000	$ 155,000
4080	Distribution Services Revenue - SSS Admin Fee	$ 364,022	$ 386,559	$ 393,049		$ 395,000	$ 395,000	$ 405,000
4080	Distribution Services Revenue - microFit Fee	$ -	$ 410	$ 3,512		$ 5,400	$ 5,400	$ 7,900
4084	Service Transaction Requests (STR) Revenues	$ 4,176	$ 12,250	$ 5,910		$ 8,000	$ 8,000	$ 8,000
4210	Rent from Electric Property	$ 496,454	$ 498,282	$ 466,557		$ 452,000	$ 452,000	$ 466,000
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	$ 4,237	$ 3,142	$ 3,031		$ 3,586	$ 3,586	$ 2,763
4355	Gain on Disposition of Utility and Other Property	$ 49,035	$ 104,332	$ 80,377		$ 64,500	$ 64,500	$ 64,000
4390	Miscellaneous Non-Operating Income	$ 197,112	$ 211,138	$ 371,811		$ 249,252	$ 249,252	$ 216,575
4405	Interest and Dividend Income	$ 171,194	$ 93,068	$ 105,133		$ 78,551	$ 78,551	$ 100,744
Specific Service Charges		$ 796,561	$ 828,825	$ 820,197	$ -	$ 813,000	$ 813,000	$ 839,000
Late Payment Charges		$ 997,439	$ 1,197,897	$ 1,072,984	$ -	$ 1,100,000	$ 1,100,000	$ 1,133,000
Other Operating Revenues		$ 1,090,884	$ 1,111,411	$ 1,057,383	$ -	$ 1,035,400	$ 1,035,400	$ 1,041,900
Other Income or Deductions		$ 421,579	$ 411,681	$ 560,353	$ -	$ 395,889	$ 395,889	$ 384,082
Total		**$ 3,306,464**	**$ 3,549,813**	**$ 3,510,917**	**$ -**	**$ 3,344,289**	**$ 3,344,289**	**$ 3,397,982**

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.
The above table assumes adoption of MIFRS as of January 1, 2013. If the adoption year differs, please adjust the table accordingly.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4235 - Miscellaneous Service Revenues

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year	Bridge Year	Test Year
					2012	2012	2013
Reporting Basis			CGAAP		CGAAP	MIFRS	MIFRS
Interval Metering Charges	$ 35,037	$ 37,426	$ 36,699		$ 37,000	$ 37,000	$ 37,000
Occupancy Charges	$ 581,128	$ 642,693	$ 637,543		$ 655,000	$ 655,000	$ 675,000
Arrears Certificates	$ 30,810	$ 23,766	$ 26,470		$ 26,000	$ 26,000	$ 26,000
Electric - Service calls	$ 2,439	$ -	$ -		$ -	$ -	$ -
Temporary service - install and remove overhead no transformer	$ 16,286	$ 18,000	$ 15,000		$ 11,917	$ 11,917	$ 12,353
Temporary service - install and remove underground no transformer	$ 2,571	$ 3,300	$ 3,900		$ 2,375	$ 2,375	$ 2,462
Temporary service - install and remove - non standard	$ 122,362	$ 71,225	$ 97,832		$ 67,708	$ 67,708	$ 70,185
Billable Services	$ 2,534	$ 25,316	-$ 5,148		$ 5,000	$ 5,000	$ 8,000
Misc Customer Service Charges	$ 3,393	$ 7,099	$ 7,901		$ 8,000	$ 8,000	$ 8,000
Returned cheque charges	$ 32,009	$ 23,234	$ 20,102		$ 28,045	$ 28,045	$ 28,867
Collection of account charge - no disconnection	$ 364,453	$ 487,679	$ 478,980		$ 472,570	$ 472,570	$ 486,426
Disconnect/reconnect at meter - during regular hours	$ 97,523	$ 150,454	$ 173,018		$ 147,385	$ 147,385	$ 151,707
recorded in account 5330 “collection charges” and reported as a credit to “billing and collecting” costs	-$ 493,985	-$ 661,368	-$ 672,100		-$ 648,000	-$ 648,000	-$ 667,000
Total	**$ 796,561**	**$ 828,825**	**$ 820,197**	**$ -**	**$ 813,000**	**$ 813,000**	**$ 839,000**

Account 4225 - Late Payment Charges

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			**CGAAP**		**CGAAP**	**MIFRS**	**MIFRS**
Late Payment Charges	$ 997,439	$ 1,197,897	$ 1,072,984		$ 1,100,000	$ 1,100,000	$ 1,133,000
Total	**$ 997,439**	**$ 1,197,897**	**$ 1,072,984**	**$ -**	**$ 1,100,000**	**$ 1,100,000**	**$ 1,133,000**

Account 4082 - Retail Services Revenue

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			**CGAAP**		**CGAAP**	**MIFRS**	**MIFRS**
Retail contract initiation charge - one time charge	$ 208	$ 273	$ 261		$ 209	$ 209	$ 185
Retailer monthly fixed charge for contract administration	$ 4,248	$ 3,932	$ 4,826		$ 3,662	$ 3,662	$ 3,243
Retailer monthly customer administration charge	$ 147,775	$ 133,681	$ 115,667		$ 110,380	$ 110,380	$ 97,765
Distributor consolidated billing charge - per month per customer	$ 75,186	$ 80,065	$ 69,971		$ 62,890	$ 62,890	$ 55,703
Retailer consolidated billing credit - per month per customer	-$ 1,184	-$ 4,041	-$ 2,370		-$ 2,141	-$ 2,141	-$ 1,896
Total	**$ 226,233**	**$ 213,910**	**$ 188,355**	**$ -**	**$ 175,000**	**$ 175,000**	**$ 155,000**

Account 4080 - Distribution Services Revenue - SSS Admin Fee

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			**CGAAP**		**CGAAP**	**MIFRS**	**MIFRS**
Distribution Services Revenue - SSS Admin Fee	$ 364,022	$ 386,559	$ 393,049		$ 395,000	$ 395,000	$ 405,000
Total	**$ 364,022**	**$ 386,559**	**$ 393,049**	**$ -**	**$ 395,000**	**$ 395,000**	**$ 405,000**

Account 4080 - Distribution Services Revenue - microFit Fee

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			**CGAAP**		**CGAAP**	**MIFRS**	**MIFRS**
Distribution Services Revenue - microFit Fee	$ -	$ 410	$ 3,512		$ 5,400	$ 5,400	$ 7,900
Total	**$ -**	**$ 410**	**$ 3,512**	**$ -**	**$ 5,400**	**$ 5,400**	**$ 7,900**

Account 4084 - Service Transaction Requests (STR) Revenues

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			**CGAAP**		**CGAAP**	**MIFRS**	**MIFRS**
Request fee - per request	$ 1,814	$ 5,284	$ 2,516		$ 3,406	$ 3,406	$ 3,406
Processing fee - per request	$ 2,362	$ 6,966	$ 3,394		$ 4,594	$ 4,594	$ 4,594
Total	**$ 4,176**	**$ 12,250**	**$ 5,910**	**$ -**	**$ 8,000**	**$ 8,000**	**$ 8,000**

Account 4210 - Rent from Electric Property

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			**CGAAP**		**CGAAP**	**MIFRS**	**MIFRS**
Pole rentals	$ 360,688	$ 362,130	$ 360,346		$ 373,000	$ 373,000	$ 386,000
Administrative Bldg Space Rental	$ 117,655	$ 118,237	$ 87,827		$ 60,000	$ 60,000	$ 60,000
Duct rentals and miscellaneous	$ 18,110	$ 17,915	$ 18,384		$ 19,000	$ 19,000	$ 20,000
Total	**$ 496,454**	**$ 498,282**	**$ 466,557**	**$ -**	**$ 452,000**	**$ 452,000**	**$ 466,000**

Account 4330 - Costs and Expenses of Merchandising, Jobbing, etc.

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			**CGAAP**		**CGAAP**	**MIFRS**	**MIFRS**
Net income (expense) from merchandising, jobbin	$ 4,237	$ 3,142	$ 3,031		$ 3,586	$ 3,586	$ 2,763
Total	**$ 4,237**	**$ 3,142**	**$ 3,031**	**$ -**	**$ 3,586**	**$ 3,586**	**$ 2,763**

Account 4355 - Gain on Disposition of Utility and Other Property

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			CGAAP		CGAAP	MIFRS	MIFRS
Gain on Disposition of Utility and Other Property	$ 98,071	$ 208,665	$ 160,755		$ 129,000	$ 129,000	$ 128,000
Less: 50% of gain deducted for revenue offset calculation	-$ 49,035	-$ 104,332	-$ 80,377		-$ 64,500	-$ 64,500	-$ 64,000
Total	**$ 49,035**	**$ 104,332**	**$ 80,377**	**$ -**	**$ 64,500**	**$ 64,500**	**$ 64,000**

Account 4390 - Miscellaneous Non-Operating Income

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			CGAAP		CGAAP	MIFRS	MIFRS
Supplier Discounts - on material purchases	$ 23,371	$ 32,755	$ 25,674		$ 29,000	$ 29,000	$ 31,000
Supplier Penalties - re: material purchase agreements	$ 5,238	$ 1,543	$ 8,574		$ 4,000	$ 4,000	$ 4,000
Sale of Scrap	$ 119,871	$ 170,480	$ 311,357		$ 150,000	$ 150,000	$ 150,000
Fitness Centre Revenue	$ 3,150	$ 2,599	$ 2,100		$ 3,000	$ 3,000	$ 3,000
Miscellaneous Revenue	$ 20,394	$ 3,566	$ 5,008		$ 6,000	$ 6,000	$ 6,000
Non Refundable Customer Credits	$ 25,088	-$ 250	-$ 143		$ -	$ -	$ -
Management Fee for Renewable Energy Non-Distribution Asset	$ -	$ 444	$ 19,241		$ 57,252	$ 57,252	$ 22,575
Total	**$ 197,112**	**$ 211,138**	**$ 371,811**	**$ -**	**$ 249,252**	**$ 249,252**	**$ 216,575**

Account 4405 - Interest and Dividend Income

	2009 Actual	2010 Actual	2011 Actual²	2011 Actual²	Bridge Year 2012	Bridge Year 2012	Test Year 2013
Reporting Basis			CGAAP		CGAAP	MIFRS	MIFRS
Short-term Investment Interest	$ 8,117	$ -	$ -		$ -	$ -	$ -
Bank Deposit Interest	$ 145,871	$ 92,924	$ 100,072		$ 50,000	$ 50,000	$ 50,000
Employee Purchase Interest	$ 260	$ 374	$ 273		$ -	$ -	$ -
Miscellaneous Interest Revenue	$ 13,395	$ 3,903	-$ 1,067		$ -	$ -	$ -
Sundry A/R Interest	$ 3,551	-$ 4,190	-$ 0		$ -	$ -	$ -
Interest on Investment of Non-Distribution Renewable Generation Asset	$ -	$ 57	$ 5,855		$ 28,551	$ 28,551	$ 50,744
Deferral and Variance Accounts Interest	$ 38,563	$ 128,245	$ 287,364		$ 110,000	$ 110,000	$ 16,000
Less: Interest associated with Deferral and Variance Accounts deducted for revenue offset calculation	-$ 38,563	-$ 128,245	-$ 287,364		-$ 110,000	-$ 110,000	-$ 16,000
Total	**$ 171,194**	**$ 93,068**	**$ 105,133**	**$ -**	**$ 78,551**	**$ 78,551**	**$ 100,744**

Notes:

1 List and specify any other interest revenue

2 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2012 for financial reporting purposes, 2011 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.

3 If the applicant is adopting IFRS or an alternate accounting standard as of January 1, 2013 for financial reporting purposes, 2012 must be presented on both a CGAAP and MIFRS (or alternate accounting standard) basis.

EXHIBIT 4 – OPERATING COSTS

INDEX

Exhibit 4 – Operating Costs

MANAGER'S SUMMARY

The operating costs in this Exhibit represent the expenditures that are necessary to maintain London Hydro's distribution assets to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and government direction; and to maintain distribution business service quality and reliability at targeted performance levels.

Operating costs also include the costs incurred to provide standard distribution related services to customers connected to London Hydro's distribution system, and to meet the default service requirements of the OEB's Standard Supply Service Code and the Retail Settlement Code.

London Hydro is proposing recovery through distribution rates of the 2013 Test Year total operating costs including amortization and PILs totaling $50,685,247, as summarized in Table 4-1, below. Operating, Maintenance and Administration ("OM&A") costs for the proposed 2013 Test Year are $33,744,563.

Table 4-1 – Summary of Total Operating Cost

		2013 Test Year Compared to 2009 Actual				2013 Test Year Compared to 2009 Board Approved			
Operating Costs *(in $000's)*	**2013 TEST Year (MIFRS) ($)**	**2009 Actual (CGAAP) ($)**	**Overall Change ($)**	**Overall Change (%)**	**Average Annual Change (%)**	**2009 Board Approved (CGAAP) ($)**	**Overall Change ($)**	**Overall Change (%)**	**Average Annual Change (%)**
Operating, Maintenance & Administration	$ 33,745	$ 27,744	$ 6,001	21.6%	5.4%	$ 28,242	$ 5,503	19.5%	4.9%
Charitable Donations	100	100	-	0.0%	0.0%	50	50	100.0%	25.0%
Total Amortization Expense *(Note 1)*	15,906	15,077	829	5.5%	1.4%	15,437	469	3.0%	0.8%
Total (before PILs)	49,751	42,921	6,830	15.9%	4.0%	43,729	6,022	13.8%	3.4%
Payment in lieu of Taxes (PILs)	934	5,340	(4,406)	-82.5%	-20.6%	3,143	(2,209)	-70.3%	-17.6%
	$ 50,685	$ 48,261	$ 2,424	5.0%	1.3%	$ 46,872	$ 3,813	8.1%	2.0%

Note 1 - Total Amortization Expense includes amount ($118,000) related to the CGAAP to MIFRS Transition (1575)

MIFRS and the 2013 Rate Application:

London Hydro is expecting to adopt IFRS on January 1, 2013 for financial reporting purposes as currently required by the Accounting Standards Board ("AcSB"). Therefore, as per *Chapter 2 of the Filing Requirements for Electricity Transmission and Distribution Applications* ("Filing Requirements") dated June 28, 2012, London Hydro is required to file the cost of service application based on Modified International Financial Reporting Standards ("MIFRS").

London Hydro has complied with this requirement.

The Bridge Year (2012) is provided in Canadian Generally Accepted Accounting Principles ("CGAAP"), and both the Bridge Year (2012) and the proposed Test Year (2013) are provided in MIFRS format. London Hydro has also included the proposed Test Year (2013) in CGAAP format to assist with overall comparability and assist with the identification of the MIFRS impact on both revenue requirements and on rates.

This Exhibit also provides a summary of the dollar impacts of MIFRS on Total Distribution Expense (before PILs). Exhibit 10 provides a consolidated review of the overall impact of MIFRS on the proposed revenue requirement, and rate base, among others.

Non-Distribution Activities:

All operating and amortization expense related to activities which do not qualify for inclusion in the rate making calculations have been excluded from this Exhibit. All items that are excluded are reported in the reconciliation between London Hydro's Pro-Forma financial statements and the financial results filed in this application. See Exhibit 1, Tables 1-15 to 1-22, Pages 59 to 66.

Renewable Generation, a non-distribution activity, is excluded for rate making purposes and detailed information including pro-forma financial statements for this activity are provided within this Exhibit in the section entitled: *"Shared Services and Corporate Cost Allocations"*, on Page 98.

Overall Trends in Cost:

OM&A cost has increased year over year since the last rebasing year of 2009 and this trend is forecasted to continue in the proposed 2013 Test year. This is due primarily to:

- Salaries and wages which are trending upwards and have increased between 2.0% and 3.0% per year. The shortage of skilled resources, high demand for the same resources throughout the industry, along with union settlements which are within the industry norm are resulting in higher costs. The cumulative increase in 2013 for salaries and wages is forecast to be 10.92% over the 2009 Actuals. This is an increase of $2,081,566 based on the employee complement in 2009.
- The inclusion of Smart Meter costs in the proposed 2013 Test Year has increased OM&A by $674,900. This cost is partially offset with reductions related to the traditional meter reading cost.
- The transition to MIFRS results in lower capitalization of overheads and has increased OM&A by $336,000.
- Hardware and software license and maintenance cost has seen an overall increase of $508,495 over the 2009 Actuals. New technology and the investment in new information systems such as the billing system needed to support Time of Use (“TOU”) billing are resulting in higher OM&A costs.
- Succession planning and employee skill development is critical for London Hydro’s future success. Employee training costs have increased $158,265 over the 2009 Actuals.

The section entitled: *“Summary of Cost Drivers”* beginning on Page 20, provides further details on cost trends and the cost drivers impacting OM&A.

A full breakdown of OM&A costs, the impact of Smart Meters and MIFRS is included in the sections that follow.

Inflation Rates Used:

Although the Board suggests that GDP-IPI is the most relevant inflation rate for utilities with respect to IRM rate application, London Hydro has not utilized this or any other inflation factor in any significant way in the determination of the 2012 Bridge or 2013 Test Year forecasts. As described in Exhibit 1, in the section entitled: *"Budget Overview – Capital and Operating"* on Page 34, London Hydro uses a zero based budgeting approach. Forecasts are impacted by significant business environment changes impacting London Hydro as well as all distribution companies in the province.

Staffing Levels:

In accordance with the Filing Requirements, London Hydro has presented staffing levels in Full Time Equivalents ("FTEs") and not by headcount. An FTE has been defined as the number of actual hours worked over the total annual hours of work. For example, an employee working from July 1 to Dec 31 would be measured as .5 FTE. Both full time and part-time FTEs are measured in this way. Table 4-2, on Page 6 provides the breakdown of this increase between full time and part time resources over the period 2009 Actual to 2013 Test. In both the 2012 Bridge and 2013 Test Years, all positions are assumed to be filled for the full year. This reflects the resources required to achieve the planned operating, maintenance, and capital plans for those years.

In order to accomplish the objectives as established in the operating and capital plans, London Hydro will utilize both internal staff and external contracted labour, the proportions of which are dependent on recruitment success.

Table 4-45, on Page 96 entitled: *"Employee Compensation Breakdown"* provides year on year changes in the FTEs for both full time and part time staff.

The total staffing levels and skill requirements have changed significantly since the last rebasing year of 2009. Changes in the business environment have resulted in a proposed change in total headcount of 46.5 FTEs.

London Hydro will deploy resources between OM&A, capital, billable and other activities. Increases in resource allocation relate to the introduction of new conservation and demand programs, and changes to the levels of external contractors retained to perform capital work. The allocation of resources has increased 29.8 FTEs.

Staffing levels in OM&A have increased 16.7 FTEs over the 2009 Actuals. This is an increase of 8.4% based on the FTEs allocated to OM&A in that year. A full discussion related to the labour required to meet operating requirements is provided in the section entitled: *"Base Labour"* which begins on Page 39.

Open Positions and Impact on OM&A:

London Hydro is facing a major challenge in hiring and retaining skilled staff. This is related to shortages of available skilled resources, high demand resulting from the volume of retirements, and competition from other LDCs facing the same challenge.

At any given time, London Hydro will have a number of open positions, which impacts the total FTEs reported, however this does not impact the total OM&A cost. The overall operating plan does not change due to a shortage of internal staff. The same OEB standards for maintenance, reliability, and customer response time must continue to be met. What does change is the mix of internal and external resources used. London Hydro will counter shortages in the internal workforce with external contracted labour where necessary.

Typically, the operating and maintenance of the infrastructure is accomplished using internal labour. When a shortage of staff occurs, London Hydro will ensure that the operating requirements remain a priority and staff will be redirected from capital programs. London Hydro will "shop" for more external labour in order to accomplish the capital plan.

Recently, significant changes in the information systems required to facilitate TOU billing resulted in the need to retain additional external resources to maintain and support the system. New capital system implementation projects, have involved internal staff where possible, however, shortages resulted in higher levels of external contracted labour than is deemed optimal.

It is important to note that the review of FTE is based on the total staff complement and is before deployment to capital, billable and other activities that are not included in OM&A expense. A further example of this is related to the FTEs required for the Conservation Demand Management ("CDM") programs which are billed directly to the Ontario Power Authority ("OPA"). If London Hydro does not retain these resources there will be no OM&A impact.

It is London Hydro's intention to lessen the dependency on external contractors in numerous areas such as construction (primarily used for new development), as well as information technology. Some of the numerous benefits related to this shift are reductions in cost, improving in-house skill knowledge, consistency, and improved issue response.

Although this transition has been impacted by the demand and supply of skilled resources, London Hydro is making progress in achieving the desired balance. This is evidenced by the increase in the total internal staff being allocated to capital. See Table 4-21, on Page 43, as well as discussions on major cost drivers beginning on Page 20. As a result of the increased projected staffing levels, the 2012 Bridge and 2013 Test Years forecast significant reductions in the purchase of external consulting and contracted labour (see related discussion pertaining to Purchased Services, Page 57).

A full discussion related to the challenges and risk of not attaining and developing internal staff is provided in the section entitled *"Labour and Benefits"* which begins on Page 36.

Table 4-2 – Overall Change in Staffing Levels and Deployment

Total Staff Levels in FTEs			
	Full Time	Part Time	TOTAL
2009 Actuals	249	24	273
2013	288	31.5	319.5
Overall Change	39	7.5	46.5
Allocation to Capital, Billable, and Other Activities			
			TOTAL
2009 Actuals			(73.8)
2013			(103.6)
Overall Change			(29.8)
Change in FTE Allocated to OM&A			
			TOTAL
Total FTEs after allocations			16.7

Business Environment Changes:

London Hydro's Strategic Plan (provided in Exhibit 1, Appendix 1A) provides detailed insight into the business environment changes impacting London Hydro and the utility industry as a whole, and outlines both external and internal environment changes.

Materiality Thresholds:

London Hydro has established the materiality threshold for variance analyses at $294,000. This threshold is used to identify areas of cost increase requiring detailed explanation as per the Filing Requirements and is applied to any year on year variance by OEB account in the section entitled: "Variance Analyses". Variance reviews for the OEB Uniform System of Accounts ("USoA") begin on Page 79 of this Exhibit. The detailed calculation related to the establishment of this threshold is provided in Exhibit 1, Table 1-23, on Page 69.

Comparability Issues:

Comparability of OM&A for the Historical, Bridge, and proposed Test years is affected by significant business changes which have occurred during the period under review. As well, the inclusion of new incremental Smart Meter operating costs and the associated amortization previously recorded in deferral accounts impact the year on year comparability. Furthermore, the implementation of MIFRS as part of the Application results in significant changes for both amortization and overhead allocations. For this reason, the presentation of OM&A and amortization expense will be provided both before and after Smart Meter and MIFRS impacts. This is necessary to provide proper comparability and highlight areas of cost increase and decrease.

In 2010, London Hydro implemented an accounting change to include vehicle and equipment ("V&E") amortization in overhead rates used to allocate the cost of the fleet to operating, capital, and billable activities. Prior to that, vehicle and equipment amortization was included in amortization expense. Schedules in this Exhibit, used to compare year over year amortization expense, have been restated for comparability purposes.

Table 4-3, Page 9 provides high level historical operating costs related to London Hydro's 2009 submission, the 2009 OEB Approved, 2009 to 2011 Actual results, as well as 2012 Bridge and proposed 2013 Test Years. This Table excludes the impact of Smart Meters and MIFRS for initial comparability purposes.

Some figures presented in this and other Tables have been rounded for ease of presentation.

OM&A Excluding Smart Meter and MIFRS Impacts:

OM&A for the proposed 2013 Test Year before the impact of Smart Meter and MIFRS is $32,733,663. This is an increase of 18.0% over the 2009 Actual results or an average annual increase of 4.5% per year.

In 2010, the significant business requirements related to TOU billing and the implementation of a new customer information billing system ("CIS") among others resulted in OM&A increases of $2,455,165 or 8.8% over the 2009 Actual results. Annual increases since 2010 have been much lower at 1.9%, 4.8%, and 1.5% for 2011 Actual, 2012 Bridge, and 2013 Test Years respectively.

Details relating to the change in costs are explained at length later in this Exhibit.

Amortization Expense Excluding Smart Meter and MIFRS Impacts:

Amortization expense for the proposed 2013 Test Year before the impact of Smart Meters and MIFRS is approximately $18,431,000. This is an increase of 22.2% over the 2009 Actual results or an average annual change of 5.6% per year. Year on year increases over the period 2009 Actual to the proposed 2013 Test Year are fairly stable with increases of 5.8% (2009 to 2010), 5.7% (2010 to 2011), 5.7% (2011 to 2012 Bridge), and 3.4% (2012 Bridge to 2013 Test).

Smart Meters and Impact to OM&A and Amortization Expense:

All incremental costs incurred related to the Smart Meter program were recorded to the appropriate Smart Meter deferral accounts in compliance with OEB direction. Incremental costs are defined as costs over and above costs that were already being recovered through distribution rates established in the last rebasing year (2009).

The total smart meter operating costs were therefore reduced by approximately $330,000 annually which represented the costs already included in the distribution rates. The 2012 Bridge Year reflects the net incremental cost in OM&A.

Table 4-3 – Total Distribution Expense (before PILs)

Excluding Impact of Smart Meters and MIFRS

Total Distribution Expense (before PILS) and EXCLUDING IMPACT OF SMART METERS AND MIFRS

Description	2009 TEST as Submitted	OEB Decision Adj & Reclass *(Note 1)*	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 CGAAP BRIDGE	2013 CGAAP TEST
OM&A	$28,169,400	$ 72,263	$28,241,663	$27,744,217	$30,199,382	$30,776,581	$32,257,186	$32,733,663
Charitable Donations	50,000	-	50,000	100,000	100,000	100,000	100,000	100,000
Amortization Expense	15,919,000	(481,900)	15,437,100	15,077,495	15,950,097	16,859,795	17,818,600	18,431,000
SUB-TOTAL	**$44,138,400**	**$ (409,637)**	**$43,728,763**	**$42,921,712**	**$46,249,479**	**$47,736,377**	**$50,175,786**	**$51,264,663**

VARIANCES (%)

	(Note 2)	*(Note 3)*			
OM&A	-1.8%	8.8%	1.9%	4.8%	1.5%
Charitable Donations	100.0%	0.0%	0.0%	0.0%	0.0%
Amortization Expense	-2.3%	5.8%	5.7%	5.7%	3.4%
Total	-1.8%	7.8%	3.2%	5.1%	2.2%

Overall Variance 2009 Actual to 2013 Test	
OM&A	18.0%
Amortization Expense	22.2%
Total Distribution Expense	19.4%
Total Distribution Expense (before PILs) Average Variance per year 2009 Actual to 2013 Test	4.9%

Note 1 - See Page 34 for details on OEB Decision Adjustments and Reclass of V&E depreciation
Note 2 - 2009 OEB Approved to 2009 Actual Variances
Note 3 - Year on Year Variances (2009 Actual through 2013 Test)

Effective September 1, 2012, and in connection with the final Smart Meter Rate Application (EB-2012-0187) submitted to the Board on April 2, 2012, Smart Meter operating costs are no longer to be recorded in the deferral accounts and will form part of ongoing OM&A and Amortization expense. Incremental costs expensed in 2012 will be recovered through the Smart Meter Incremental Rate Rider ("SMIRR").

Smart Meter costs related to the proposed 2013 Test Year are being submitted as part of this current cost of service Application and details related to both the 2012 Bridge and proposed 2013 Test Year are provided in Table 4-5 on Page 11.

The total Smart Meter Program costs for the proposed 2013 Test Year are $674,900. This is the required on-going cost now to be included within OM&A and therefore included for recovery in the distribution rates. Non-recurring costs incurred in 2012 to implement the program such as a customer education campaign and additional temporary staff required to assist London Hydro's customers during the initial roll out of new bills is excluded from the proposed 2013 Test Year.

The new Smart Meter cost represents a 2.4% increase over the 2009 Actual results.

In addition, the amortization associated with the Smart Meter assets will be included as a new on-going element of amortization expense. Smart Meter amortization for the 2012 Bridge and proposed 2013 Test Years is $2,193,400 and $2,233,200 respectively. The incremental amortization expense for the proposed 2013 Test Year represents an increase of 14.8% over the 2009 Actual results.

The overall impact of the Smart Meter program on total distribution expense before PILs is $2,908,100 or 6.8% as shown in Table 4-4, below. This increase is partially offset by cost savings related to the traditional method of reading meters.

Table 4-4 – Impact of Smart Meter Program

	2009 Actuals	2013 SM Cost	SM Cost as % of 2009 Actuals
OM&A	$27,744,217	$ 674,900	2.4%
Charitable Donations	100,000	-	0.0%
Amortization Expense	15,077,495	2,233,200	14.8%
Total	$42,921,712	$ 2,908,100	**6.8%**
Cost per Customer (using 2009 customer statistics as base)			
OM&A	$ 189	$ 5	2.4%
Amortization Expense	$ 103	$ 15	14.8%

Note - other cost savings such as reductions in meter reading partially offset the impact to OM&A above

Table 4-5 – Recurring and Non Recurring Smart Meter Operating Cost

RECURRING AND NON-RECURRING Smart Meter Program Expense Detail - 2012 and 2013 ***(Note 3)***

MAJOR COST CATEGORIES >>>	Labour		Purchased Services		Office Equipment Services & Mtce		Employee Training & Expense		Regulatory & Other		TOTAL	
Expense Description:	**2012 $**	**2013 $**	**2012 $**	**2013 $**	**2012 $**	**2013 $**	**2012 $**	**2013 $**	**2012 $**	**2013 $**	**2012 $**	**2013 $**
RECURRING EXPENSE												
LAN Mtce - Sensus RNI Licences/Mtce fees			49,900	53,400							49,900	53,400
LAN Mtce - Flexnet Licences/Mtce fees			177,200	180,500							177,200	180,500
LAN Mtce - Radio Frequency Licensing fees/ Occupancy Cost									44,200	44,200	44,200	44,200
LAN Mtce - Long Term Site Attachment fees									28,600	29,200	28,600	29,200
RNI data management - 1 FTE	104,800	122,400									104,800	122,400
Backhaul network security - 1 FTE	106,400	109,600									106,400	109,600
Employee training - ongoing knowledge upgrades							4,000	4,000			4,000	4,000
MDUS & ODS Mtce fees					52,500	53,600					52,500	53,600
AMI - SAP Annual System Mtce fee					51,000	51,000					51,000	51,000
WAN Mtce - site mtce			5,000	5,000							5,000	5,000
WAN Mtce - Capella/Belair Licences/Mtce fees					15,000	15,000					15,000	15,000
Other - Firewall maintenance, misc					7,000	7,000					7,000	7,000
Sub-Total Recurring	**211,200**	**232,000**	**232,100**	**238,900**	**125,500**	**126,600**	**4,000**	**4,000**	**72,800**	**73,400**	**645,600**	**674,900**
NON-RECURRING EXPENSE (STARTUP COST)												
Temporary Labour for initial Smart Meter record setup	5,000										5,000	
Temporary Labour required for roll-out of TOU billing (handle initial expected increase in customer inquiries)	275,100										275,100	
Public Relations promotion of TOU - customer education campaign			130,000								130,000	
To respond to customer demand for additional information choices			15,000								15,000	
AWD Airtime					5,300						5,300	
Sub - Total Non Recurring	**280,100**	**-**	**145,000**	**-**	**5,300**	**-**	**-**	**-**	**-**	**-**	**430,400**	**-**
Incremental Cost Adjustment *(Note 1)*									(330,000)		(330,000)	
TOTAL	**491,300**	**232,000**	**377,100**	**238,900**	**130,800**	**126,600**	**4,000**	**4,000**	**(257,200)**	**73,400**	**746,000**	**674,900**
											(Note 1)	*(Note 2)*

Note 1 - Total Incremental Smart Meter Program expense incurred in 2012 will be recovered with the Smart Meter Incremental Rate Rider ("SMIRR"). The total cost above is adjusted for meter reading cost savings (which remains part of existing rates approved in 2009 COS). This results in a true "incremental cost" requiring separate recovery through the SMIRR.

Note 2 - In order to simplify comparability of major cost categories (2009 Actual - 2013 TEST), these TOU costs are summarized and segregated on the detailed cost Tables provided (see Tables 4-8 to 4-10)

Note 3 - Smart Meter Program costs remain the same under both CGAAP and MIFRS

MIFRS and Impact to OM&A and Amortization Expense:

The adoption of MIFRS for rate making purposes has four basic impacts to London Hydro's OM&A and Amortization Expense:

- ***Increase*** to OM&A cost due to lower capitalization of material handling overheads
- ***Decrease*** to OM&A cost due to lower fleet depreciation expense within the overheads
- ***Decrease*** to amortization with the introduction of new useful service lives for Property, Plant, and Equipment ("PP&E")
- ***Increase*** to amortization expense related to the introduction of a new OEB Transitional Deferral Account (1575)

The implementation of MIFRS results in a total increase in OM&A in the amount of $336,000 in the proposed 2013 Test Year or 1.2% over the 2009 Actual results. Amortization is reduced by $4,758,000 or 31.6% over the same time period.

The overall impact of MIFRS on total distribution expense before PILs is a decrease of $4,422,000 or 10.3% as shown in Table 4-6, below.

Table 4-6 – Impact of MIFRS Adoption for Rate Making Purposes

	2009 Actuals	2013 MIFRS Impact	MIFRS Impact as % of 2009 Actuals
OM&A	$27,744,217	$ 336,000	1.2%
Charitable Donations	100,000	-	0.0%
Amortization Expense	15,077,495	(4,758,000)	-31.6%
Total	$42,921,712	$ (4,422,000)	**-10.3%**
Cost per Customer (using 2009 customer statistics as base)			
OM&A	$ 189	$ 2	1.2%
Amortization Expense	$ 103	$ (32)	-31.6%

Changes to Overhead Rates Applied to Material:

Transitioning to MIFRS for rate making purposes has changed the allocation of overhead on materials between OM&A and capital. In the 2012 Bridge Year and proposed 2013 Test Year OM&A is $470,700 and $496,000 higher respectively, due to this change in allocation practice.

Changes to Overhead Rates Related to Fleet:

Vehicles and equipment costs are allocated to operating, capital, and billable activities using an hourly overhead rate. Included in this rate is V&E depreciation expense. With the transition to MIFRS, V&E depreciation has declined; therefore the allocation to OM&A activities will be impacted. The total reduction to OM&A expense for the 2012 Bridge Year and the proposed 2013 Test Year related to this change is $143,000 and $160,000, respectively. See Table 4-7 on Page 15. A detailed schedule related to the impact of new services lives is provided in Exhibit 10, Table 10-9, on Page 12. Full detail on the change in service lives, and amortization by component are presented in the section entitled: "*Depreciation, Amortization, and Depletion"* beginning on Page 107 of this Exhibit.

Changes in Useful Service Lives for PP&E:

New service lives decreased amortization expense $4,876,000 in the proposed 2013 Test Year. Full detail on the change in service lives, and amortization by PP&E component is presented in the section entitled: "*Depreciation, Amortization, and Depletion"* beginning on Page 107 of this Exhibit.

Amortization of Transitional Deferral Account (1575) to Amortization Expense:

As directed by the Board, London Hydro is seeking approval for the establishment of a MIFRS Transitional Deferral Account (OEB - 1575). The detailed calculation of the total amount in this account is provided in Exhibit 10, on Page 9. London Hydro will seek to recover $471,922 over a four year period (2013 to 2016). Amortization expense for 2013 includes approximately $118,000 related to this transitional issue. See Table 4-7 on Page 15.

Overall Change in OM&A and Amortization Expense:

OM&A for the proposed 2013 Test Year including the impact of Smart Meters and MIFRS is $33,744,563, an increase of $6,000,346 or 21.6% over the 2009 CGAAP Actual results.

Amortization expense including the impact of Smart Meters and MIFRS is approximately $15,906,200, an increase of $828,705 or 5.5% over the 2009 CGAAP Actual results.

Total distribution expense (before PILs) for the proposed 2013 Test Year is $49,750,763, an increase of $6,829,051 or 15.9% over the 2009 CGAAP Actual results. This is an average annual increase of 4.0%. Table 4-8 on Page 16 provides details under both CGAAP and MIFRS standards.

Table 4-8 also provides details related to OM&A expense for activities such as Operating, Maintenance, Billing and Collecting, and Administrative and General Expense, among others in accordance with the OEB Uniform System of Accounts ("USoA"). Year over year variances, with cumulative and average annual changes are included in Table 4-9 on Page 17.

Table 4-10 on Page 18 provides details related to OM&A expense for major cost categories, such as Labour and Benefits, Purchased Services, Materials and Supplies, Postage, and Employee Training and Development, among others. Year over year variances are included in Table 4-11 on Page 19.

Table 4-7 – Impact of Smart Meters and MIFRS on Total Distribution Expense (before PILs)

Total Distribution Expense (before PILS) INCLUDING SMART METER AND MIFRS to OM&A										
Description	2009 TEST as Submitted	OEB Decision Adj & Reclass	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 CGAAP BRIDGE	2013 CGAAP TEST	2012 MIFRS BRIDGE	2013 MIFRS TEST
OM&A	$28,169,400	$ 72,263	$28,241,663	$27,744,217	$30,199,382	$30,776,581	$32,257,186	$32,733,663	$32,257,186	$ 32,733,663
Adjust for:										
Overhead Allocation	-	-	-	-	-	-	-	-	470,700	496,000
V&E Allocation	-	-	-	-	-	-	-	-	(143,000)	(160,000)
Non-recurring SM O&M	-	-	-	-	-	-	325,900	-	325,900	-
Recurring SM O&M	-	-	-	-	-	-	420,100	674,900	420,100	674,900
	28,169,400	72,263	28,241,663	27,744,217	30,199,382	30,776,581	33,003,186	33,408,563	33,330,886	33,744,563
Amortization Expense	15,919,000	- 481,900	15,437,100	15,077,495	15,950,097	16,859,795	17,818,600	18,431,000	17,818,600	18,431,000
Adjust for:										
Transition (1575) Recovery	-	-	-	-	-	-	-	-	-	118,000
New Service Lives - PP&E	-	-	-	-	-	-	-	-	144,000	(4,876,000)
Incremental Smart Meter	-	-	-	-	-	-	2,193,400	2,233,200	2,193,400	2,233,200
	15,919,000	(481,900)	15,437,100	15,077,495	15,950,097	16,859,795	20,012,000	20,664,200	20,156,000	15,906,200
Charitable Donations	50,000	-	50,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
TOTAL DISTRIBUTION EXPENSE	**$44,138,400**	**$ (409,637)**	**$43,728,763**	**$42,921,712**	**$46,249,479**	**$47,736,377**	**$53,115,186**	**$54,172,763**	**$53,586,886**	**$ 49,750,763**
VARIANCES (%)										
				(Note 1)	(Note 2)					
Total				-1.8%	7.8%	3.2%	11.3%	2.0%		
Total Overall Variance 2009 Actual to 2013 Test								26.2%		15.9%
Total Average Variance per year 2009 Actual to 2013 Test								6.6%		4.0%
									(Note 3)	
Incremental MIFRS Impact									0.9%	-8.2%

Note 1 - 2009 OEB Approved to 2009 Actual Variances
Note 2 - Year over Year Variances (2009 Actual through 2013 Test)
Note 3 - Incremental Impact of MIFRS

Table 4-8 – Summary of Total Distribution Expense (before PILs)

SUMMARY OF TOTAL Distribution Expense (Before PILs)										
Description	**2009 TEST as Submitted**	**OEB Decision Adj & Reclass**	**2009 OEB Approved**	**2009 ACTUAL**	**2010 ACTUAL**	**2011 ACTUAL**	**2012 CGAAP BRIDGE**	**2013 CGAAP TEST**	**2012 MIFRS BRIDGE**	**2013 MIFRS TEST**
OM&A Expenses (excluding SM)										
Operations	$ 7,180,864	$(151,100)	$ 7,029,764	$ 7,239,743	$ 7,238,401	$ 7,874,084	$ 8,327,337	$ 8,430,782	$ 8,655,037	$ 8,812,049
Maintenance	6,323,653	241,000	6,564,653	5,643,217	6,388,593	6,782,183	7,533,455	7,836,959	7,533,455	7,791,693
Billing and Collections	4,392,700	-	4,392,700	4,567,324	4,112,134	4,225,884	3,813,234	3,526,765	3,813,234	3,526,765
Community Relations	316,579	-	316,579	352,152	251,175	178,731	197,052	205,337	197,052	205,337
Administrative and General Exp	8,546,464	(17,637)	8,528,827	8,291,876	10,276,374	10,098,365	10,483,575	10,719,700	10,483,575	10,719,700
Insurance Expense	459,100	-	459,100	420,500	394,895	411,307	416,400	427,860	416,400	427,860
Bad Debt Expense	535,000	-	535,000	825,000	1,120,000	800,000	1,000,000	1,000,000	1,000,000	1,000,000
Advertising Expenses	415,040	-	415,040	404,405	417,810	406,027	486,132	586,260	486,132	586,260
Other Distribution Expenses									-	-
OM&A expense (excluding SM)	28,169,400	72,263	28,241,663	27,744,217	30,199,382	30,776,581	32,257,186	32,733,663	32,584,886	33,069,663
Incremental Smart Meter Expense										
Operations	-	-	-	-	-	-	5,000	-	5,000	-
Billing and Collections	-	-	-	-	-	-	49,900	122,400	49,900	122,400
Administrative and General Exp	-	-	-	-	-	-	561,100	552,500	561,100	552,500
Advertising Expenses	-	-	-	-	-	-	130,000	-	130,000	-
Incremental Smart Meter Expense	-	-	-	-	-	-	746,000	674,900	746,000	674,900
Total OM&A Expense	**28,169,400**	**72,263**	**28,241,663**	**27,744,217**	**30,199,382**	**30,776,581**	**33,003,186**	**33,408,563**	**33,330,886**	**33,744,563**
Charitable Donations	50,000	-	50,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Amortization Expense	15,919,000	(481,900)	15,437,100	15,077,495	15,950,097	16,859,795	20,012,000	20,664,200	20,156,000	15,906,200
Total Distribution Exp Before PILs	$44,138,400	$(409,637)	$43,728,763	$42,921,712	$46,249,479	$47,736,377	$53,115,186	$54,172,763	$53,586,886	$49,750,763

Table 4-9 – CGAAP VARIANCES: Summary of Total Distribution Expense (Before PILs)

VARIANCES - SUMMARY OF TOTAL DISTRIBUTION EXPENSE (Before PILs)														
	CGAAP													
Description	2009 Board Approved to 2009 Actual		2010 Actual to 2009 Actual		2011 Actual to 2010 Actual		2012 BRIDGE to 2011 Actual		2013 TEST to 2012 BRIDGE		Cummulative 2009 Actual to 2013 TEST		Average 2009 Actual to 2013 TEST	
	$	%	$	%	$	%	$	%	$	%	$	%	$	%
OM&A Expenses (excluding SM)														
Operations	209,979	3.0	(1,342)	(0.0)	635,683	8.1	453,253	5.8	103,445	1.2	1,191,039	16.5	297,760	4.1
Maintenance	(921,436)	(14.0)	745,376	13.2	393,590	5.8	751,272	11.1	303,505	4.0	2,193,742	38.9	548,436	9.7
Billing and Collections	174,624	4.0	(455,190)	(10.0)	113,750	2.7	(412,649)	(9.8)	(286,470)	(7.5)	(1,040,560)	(22.8)	(260,140)	(5.7)
Community Relations	35,573	11.2	(100,976)	(28.7)	(72,444)	(40.5)	18,321	10.3	8,284	4.2	(146,815)	(41.7)	(36,704)	(10.4)
Administrative and General Exp	(236,951)	(2.8)	1,984,498	23.9	(178,009)	(1.8)	385,210	3.8	236,124	2.3	2,427,824	29.3	606,956	7.3
Insurance Expense	(38,600)	(8.4)	(25,605)	(6.1)	16,412	4.0	5,094	1.2	11,460	2.8	7,360	1.8	1,840	0.4
Bad Debt Expense	290,000	54.2	295,000	35.8	(320,000)	(40.0)	200,000	25.0	-	-	175,000	21.2	43,750	5.3
Advertising Expenses	(10,635)	(2.6)	13,404	3.3	(11,783)	(2.9)	80,105	19.7	100,129	20.6	181,855	45.0	45,464	11.2
Other Distribution Expenses														
OM&A expense (excluding SM)	(497,446)	(1.8)	2,455,165	8.8	577,199	1.9	1,480,605	4.8	476,477	1.5	4,989,446	18.0	1,247,361	4.5
Incremental Smart Meter Expense														
Operations	-	-	-	-	-	-	5,000	100.0	(5,000)	(100.0)	-	-	-	-
Billing and Collections	-	-	-	-	-	-	49,900	100.0	72,500	145.3	122,400	100.0	30,600	25.0
Administrative and General Exp	-	-	-	-	-	-	561,100	100.0	(8,600)	(1.5)	552,500	100.0	138,125	25.0
Advertising Expenses	-	-	-	-	-	-	130,000	100.0	(130,000)	(100.0)	-	-	-	-
Incremental Smart Meter Expense	-	-	-	-	-	-	746,000	100.0	(71,100)	(9.5)	674,900	100.0	168,725	25.0
Total OM&A Expense	**(497,446)**	**(1.8)**	**2,455,165**	**8.8**	**577,199**	**1.9**	**2,226,605**	**7.2**	**405,377**	**1.2**	**5,664,346**	**20.4**	**1,416,086**	**5.1**
Charitable Donations	50,000	100.0	-	-	-	-	-	-	-	-	-	-	-	-
Amortization Expense	(359,605)	(2.3)	872,602	5.8	909,699	5.4	3,152,205	18.7	652,200	3.3	5,586,705	37.1	1,396,676	9.3
Total Distribution Expenses Before PILs	**(807,051)**	**(1.8)**	**3,327,767**	**7.8**	**1,486,898**	**3.1**	**5,378,809**	**11.3**	**1,057,577**	**2.0**	**11,251,051**	**26.2**	**2,812,763**	**6.6**

Table 4-10 - Summary of OM&A Costs by MAJOR COST CATEGORY

SUMMARY OF OM&A COSTS BY MAJOR COST CATEGORY

Major Cost Category	2009 TEST as Submitted	OEB Decision Adjustments Required	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE CGAAP	2013 BRIDGE CGAAP	2012 BRIDGE MIFRS	2013 TEST MIFRS
LABOUR & BENEFITS:	$19,393,700	$ (225,000)	$19,168,700	$18,936,138	$20,399,946	$20,868,220	$22,057,500	$22,852,300	$22,057,500	$22,852,300
NON LABOUR COST ELEMENTS:										
Purchased Services	4,342,000		4,342,000	4,072,391	5,142,670	5,014,988	4,796,900	4,775,600	4,796,900	4,775,600
Materials & Supplies	1,074,500		1,074,500	1,002,008	1,019,451	1,005,394	1,133,986	1,175,963	1,133,986	1,175,963
Bad Debts	535,000		535,000	825,000	1,120,000	800,000	1,000,000	1,000,000	1,000,000	1,000,000
Property Taxes and Insurance	1,222,000		1,222,000	1,136,041	1,122,764	1,116,903	1,135,700	1,148,500	1,135,700	1,148,500
Facilities Maintenance and Repair	1,531,800		1,531,800	1,468,387	1,681,819	1,616,108	1,710,500	1,738,000	1,710,500	1,738,000
Office Equipment Services and Maintenance	1,324,000		1,324,000	1,342,531	1,427,800	1,748,632	1,841,700	1,792,600	1,841,700	1,792,600
Postage	975,000		975,000	874,451	963,197	1,044,174	1,035,000	1,070,000	1,035,000	1,070,000
Fleet Operations and Maintenance	1,079,800	481,900	1,561,700	1,414,617	1,333,134	1,659,625	1,849,000	2,086,000	1,492,000	1,685,000
Corporate Training & Employee Expenses	932,900	(125,000)	807,900	761,043	734,884	1,030,685	1,060,500	1,025,800	1,060,500	1,025,800
Rental Regulatory & Other expenses	1,023,400	(17,637)	1,005,763	1,113,329	897,563	1,085,981	1,111,700	1,129,800	1,111,700	1,129,800
Studies and Special Projects	109,000		109,000	66,996	62,178	59,964	165,000	165,000	165,000	165,000
TOTAL NON-LABOUR COST ELEMENTS:	14,149,400	339,263	14,488,663	14,076,794	15,505,460	16,182,453	16,839,986	17,107,263	16,482,986	16,706,263
ALLOCATIONS: Stores and Fleet	(1,715,700)		(1,715,700)	(1,658,543)	(1,890,069)	(2,136,291)	(2,382,100)	(2,547,700)	(1,697,400)	(1,810,700)
COST RECOVERIES:	(3,658,000)	(42,000)	(3,700,000)	(3,610,172)	(3,815,955)	(4,137,801)	(4,258,200)	(4,678,200)	(4,258,200)	(4,678,200)
SMART METER COSTS: Table 4-5										
Labour							491,300	232,000	491,300	232,000
Non-Labour							254,700	442,900	254,700	442,900
	$28,169,400	**$ 72,263**	**$28,241,663**	**$27,744,217**	**$30,199,382**	**$30,776,581**	**$33,003,186**	**$33,408,563**	**$33,330,886**	**$33,744,563**

Table 4-11 – VARIANCES: Summary of OM&A Major Cost Category

VARIANCES - SUMMARY OF OM&A BY MAJOR COST CATEGORY														
	CGAAP										MIFRS Compared to CGAAP			
Major Cost Category	2009 Board Approved to 2009 Actual		2010 Actual to 2009 Actual		2011 Actual to 2010 Actual		2012 BRIDGE to 2011 Actual		2013 TEST to 2012 BRIDGE		2012 BRIDGE		2013 TEST	
	$	%	$	%	$	%	$	%	$	%	$	%	$	%
LABOUR AND BENEFITS:	(232,562)	-1.2%	1,463,809	7.7%	468,274	2.3%	1,189,280	23.7%	794,800	3.6%	-	0.0%	-	0.0%
NON LABOUR COST ELEMENTS:														
Purchased Services	(269,609)	-6.2%	1,070,279	26.3%	(127,682)	-2.5%	(218,088)	-4.3%	(21,300)	-0.4%	-	0.0%	-	0.0%
Materials & Supplies	(72,492)	-6.7%	17,443	1.7%	(14,057)	-1.4%	128,592	12.8%	41,977	3.7%	-	0.0%	-	0.0%
Bad Debts	290,000	54.2%	295,000	35.8%	(320,000)	-28.6%	200,000	25.0%	-	0.0%	-	0.0%	-	0.0%
Property Taxes	(85,959)	-7.0%	(13,277)	-1.2%	(5,861)	-0.5%	18,797	1.7%	12,800	1.1%	-	0.0%	-	0.0%
Facilities Maintenance and Repair	(63,413)	-4.1%	213,432	14.5%	(65,711)	-3.9%	94,392	5.8%	27,500	1.6%	-	0.0%	-	0.0%
Office Equipment Services and Maintenance	18,531	1.4%	85,269	6.4%	320,832	22.5%	93,068	5.3%	(49,100)	-2.7%	-	0.0%	-	0.0%
Postage	(100,549)	-10.3%	88,747	10.1%	80,976	8.4%	(9,174)	-0.9%	35,000	3.4%	-	0.0%	-	0.0%
Fleet Operations and Maintenance	(147,083)	-9.4%	(81,483)	-5.8%	326,491	24.5%	189,375	11.4%	237,000	12.8%	(357,000)	-19.3%	(401,000)	-19.2%
Corporate Training & Employee Expenses	(46,857)	-5.8%	(26,159)	-3.4%	295,801	40.3%	29,815	2.9%	(34,700)	-3.3%	-	0.0%	-	0.0%
Rental Regulatory & Other expenses	107,566	10.7%	(215,766)	-19.4%	188,418	21.0%	25,719	2.4%	18,100	1.6%	-	0.0%	-	0.0%
Studies and Special Projects	(42,004)	-38.5%	(4,818)	-7.2%	(2,214)	-3.6%	105,036	175.2%	-	0.0%	-	0.0%	-	0.0%
TOTAL NON LABOUR COST ELEMENTS:	(411,869)	-2.8%	1,428,666	10.1%	676,993	4.4%	657,533	4.1%	267,277	1.6%	(357,000)	-2.1%	(401,000)	-2.3%
ALLOCATIONS: Stores and Fleet	57,157	-3.3%	(231,526)	14.0%	(246,222)	13.0%	(245,809)	11.5%	(165,600)	7.0%	684,700	-28.7%	737,000	-28.9%
COST RECOVERIES:	89,828	-2.4%	(205,784)	5.7%	(321,845)	8.4%	(120,399)	2.9%	(420,000)	9.9%	-	0.0%	-	0.0%
SMART METER COSTS														
Labour							491,300	100.0%	(259,300)	-52.8%	-	0.0%	-	0.0%
Non-Labour							254,700	100.0%	188,200	73.9%	-	0.0%	-	0.0%
	(497,446)	**-1.8%**	**2,455,165**	**8.8%**	**577,199**	**1.9%**	**2,226,605**	**7.2%**	**405,377**	**1.2%**	**327,700**	**1.0%**	**336,000**	**1.0%**

SUMMARY OF COST DRIVERS:

Since London Hydro's last rebasing year the electricity distribution sector has gone through a period of significant change. This section of London Hydro's application addresses the major cost drivers that have affected the company and provides both quantitative and qualitative evidence to support the change in OM&A and amortization expense.

The costs included in this section include costs related to Smart Meters. Smart Meters represent one of the significant cost drivers impacting the proposed 2013 Test Year.

The impact of the transition to MIFRS is excluded from this cost analysis, as it has been discussed in detail in the preceding section entitled: "*MIFRS and Impact to OM&A and Amortization Expense"* which begins on Page 12 of this Exhibit. MIFRS transition impacts are also detailed in Exhibit 10.

Change provides both opportunities and challenges, and London Hydro's strategic plan addresses both by establishing best practices and corporate goals in keeping with its Mission Statement:

> **2. MISSION STATEMENT**
>
> London Hydro is dedicated to the pursuit of excellence in safety, reliability, and efficiently distributing electricity to its customers at competitive rates.[1]

Cost drivers are defined as specific events or circumstance that impact operating cost. They are the reasons "why" costs have changed and are critical in the understanding of London Hydro's future operating requirements. The strategic plan provides additional insight related to the major cost drivers. See Exhibit 1, Appendix 1A.

The major cost drivers affecting London Hydro's operating expense are:

- Negotiated Wage Settlements
- Benefit Cost Increases
- Change in Resource Mix and Deployment – (external contractor/internal labour)

- Technology Advancements
- Regulatory Compliance
- Succession Planning
- Skilled Resources Demand and Supply
- Out-Sourcing
- Launch of TOU Billing
- Smart Meter Implementation
- Changes in Operating Program Scope
- Economic Impacts
- Service Contract Negotiations
- Commodity Price Increases in Excess of Inflation
- Environmental Commitments

Inflationary impacts, although present, are implicit and not explicit in nature. Although inflation is a cost driver it is not it is not explained separately.

OM&A cost drivers are summarized in the following three Tables:

Table 4-12, Page 22 - Cost Drivers: Labour

Table 4-13, Pages 23 to 28 - Cost Drivers: Non Labour

Table 4-14, Page 29 - Cost Drivers: Cost Recoveries

Summarized explanations are provided within these Tables. A full commentary is included in the section entitled: "*Variance Analyses*" which begins on Page 34 of this Exhibit.

Table 4-12 – Summary of Cost Drivers: Labour

Note: Costs are presented in CGAAP, no MIFRS impacts. Allocations to capital, billable and other activities is shown under "Deployment of Resources"		2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST
TOTAL Labour in OM&A - 2009 ACTUALS to 2013 TEST		**$18,936,138**	**$20,399,946**	**$20,868,220**	**$22,548,800**	**$23,084,300**
Year over Year Change ($)			$ 1,463,809	$ 468,274	$ 1,680,580	$ 535,500
Cumulative Change ($)						$ 4,148,162
Year over Year Change (%)			7.7%	2.3%	8.1%	2.4%
Cumulative Change (%)						21.9%
		Year on Year Change				**Total Change**
Cost Drivers: Labour	**Description**	**2009 Actual to 2010 Actual**	**2010 Actual to 2011 Actual**	**2011 Actual to 2012 BRIDGE**	**2012 BRIDGE to 2013 TEST**	**2009 Actual to 2013 TEST**
		$	**$**	**$**	**$**	**$**
Wage Settlements	The cumulative increase in wage settlements is 10.92% over the 2009 - 2013 period. The current contract with the Power Workers' Union expires Dec 31, 2012.	381,341	486,209	598,037	615,978	**2,081,566**
Change in Employee Complement	Total headcount, both full time and part-time have increased in order to: address changing technology, support new OPA programs, customer demand, succession planning, regulatory compliance, time of use and bill complexity, and a change in resourcing mix to reduce external contractors and increase internal labour. See full discussion related to Base Labour in this Exhibit, Page 39	667,407	482,445	2,222,733	175,322	**3,547,907**
Benefit Cost	Benefit Costs, particularly pension cost (OMERS) is increasing significantly. See Table 4-23, Page 52	577,398	317,779	794,599	419,200	**2,108,976**
Deployment of Resources	Changing the mix of internal labour and external contractors. This results in increases to the complement, however is partially offset with higher allocations to capital, billable and other activities. All labour and benefit costs related to CDM are allocated out of OM&A	(166,903)	(1,018,431)	(1,683,436)	(687,900)	**(3,556,670)**
Overtime	Although wages have increase 10.92% since 2009, actual hours of overtime have declined. See Table 4-25, and Table 4-26, Pages 54 and 55	4,566	200,271	(251,354)	12,900	**(33,616)**
TOTAL ANNUAL CHANGE - LABOUR IN OM&A		**1,463,809**	**468,274**	**1,680,580**	**535,500**	**4,148,162**

Table 4-13 - Summary of Cost Drivers: Non-Labour

Note: Costs are presented in CGAAP, and are prior to allocations to capital, billable, and other activities. Non-Labour Smart Meter Costs are included.	**2009 ACTUAL**	**2010 ACTUAL**	**2011 ACTUAL**	**2012 BRIDGE**	**2013 TEST**
TOTAL Non-Labour Costs in OM&A - 2009 ACTUALS to 2013 TEST	**$14,076,794**	**$15,505,460**	**$16,182,453**	**$17,094,686**	**$17,550,163**
Year over Year Change (%)		$ 1,428,666	$ 676,993	$ 912,233	$ 455,477
Cumulative Change ($)					$ 3,473,369
Year over Year Change ($)		10.1%	4.4%	5.6%	2.7%
Cumulative Change (%)					24.7%

		Annual Change				**Total Change**
Cost Drivers: Non Labour	**Description**	**2009 Actual to 2010 Actual**	**2010 Actual to 2011 Actual**	**2011 Actual to 2012 BRIDGE**	**2012 BRIDGE to 2013 TEST**	**2009 Actual to 2013 TEST**
		$	**$**	**$**	**$**	**$**
<u>CHANGE IN PROGRAM SCOPE/PROGRAM ENDS</u>						
PCB Removal Program	London Hydro's program to become 100% PCB free has been accomplished and future budgets include only an on-going maintenance function	(22,684)	5,328	(328)	-	(17,684)
Wholesale Metering	London Hydro has taken full responsibility of these metering points and will no longer incur one-time exit fees or legacy meter service provider fees from Hydro One related to transition	(24,716)	20,151	(25,608)	3,300	(26,872)
Smart Meter Start-up Cost	Non - labour Start up costs will be recovered through SMIRR			150,300	(150,300)	-
	Adjustment to reflect incremental costs for recovery			(330,000)	330,000	-
Epost	Program ended in 2011 as not cost effective, new on-line services offered on London Hydro Website to meet customer demand	2,975	(14,090)	(32,033)	-	(43,149)
Year over Year and Total Change - 2009 to 2013		**(44,425)**	**11,389**	**(237,669)**	**183,000**	**(87,705)**

Table 4-13 - Summary of Cost Drivers: Non-Labour *Cont'd.*

		Annual Change				Total Change
Cost Drivers: Non Labour	**Description**	**2009 Actual to 2010 Actual**	**2010 Actual to 2011 Actual**	**2011 Actual to 2012 BRIDGE**	**2012 BRIDGE to 2013 TEST**	**2009 Actual to 2013 TEST**
		$	**$**	**$**	**$**	**$**
NEW PROGRAMS - TECHNOLOGY - REGULATORY						
Smart Meter - Ongoing Non Labour OM&A	See detailed tab of new recurring smart meter spending Table 4-5, Page 11. These costs are partially offset with reductions in meter reading cost	-	-	434,400	8,500	442,900
Billing System (TOU) - Software and Hardware Mtce and License Fees	To prepare for the introduction of TOU rates, added bill complexity and to provide flexibility to adopt regulatory changes , London Hydro implemented a new billing system in 2009. This and other new technology results in changes to hardware and software maintenance costs.	69,137	402,594	89,064	(52,200)	508,595
Billing System (TOU) - System Support	SAP system support utilizes both internal labour and external contracted maintenance support services. This required external support peaked in 2011 at $1,751,000 and with business reengineering is declining to an ongoing maintenance level in 2013 Test Year	881,916	61,519	(450,346)	(42,300)	450,788
Studies and Special Projects	Studies may vary from year to year, however, continual need for studies to take advantage of new technology, and assess new programs and identify new opportunities	2,074	(6,823)	51,369	-	46,620
Community Relations - Information Programs	New expanded programs to inform and educate customer related to TOU billing, regulatory, new programs, etc.	6,815	(46,735)	87,872	13,700	61,653
OEB Hearing Expense	Timing of actual expense related to the 2009 Cost of Service Application results in year over year comparability issues. The 2013 Test Year includes only 1/4 of the total rate application cost to be recovered 2013 - 2017	(161,345)	(30,000)	120,000	500	(70,845)
Year over Year and Total Change - 2009 to 2013		**798,597**	**380,556**	**332,359**	**(71,800)**	**1,439,712**

Table 4-13 - Summary of Cost Drivers: Non-Labour *Cont'd*.

Cost Drivers: Non Labour	Description	Annual Change: 2009 Actual to 2010 Actual	Annual Change: 2010 Actual to 2011 Actual	Annual Change: 2011 Actual to 2012 BRIDGE	Annual Change: 2012 BRIDGE to 2013 TEST	Total Change: 2009 Actual to 2013 TEST
		$	$	$	$	$
TECHNOLOGY CHANGE						
Contracted Meter Reading	With the introduction of TOU and new technology for wireless meter readings the traditional meter reading is replaced. Remaining meter reading cost is mainly related to the water readings and are recovered through the Service Level Agreement with the City of London. See Exhibit 4, Shared Service and Corporate Cost Allocation, Page 99.	(63,828)	(185,627)	52,431	(100,000)	(297,024)
Year over Year and Total Change - 2009 to 2013		**(63,828)**	**(185,627)**	**52,431**	**(100,000)**	**(297,024)**
ECONOMIC - REGULATORY COMPLIANCE						
Contracted Collection Services	Consumers continue to have difficulty paying bills due to the combined impact of the economy, regulated price increases, and TOU billing. London Hydro negotiated new pricing in 2011.	96,752	9,166	7,810	2,500	116,228
Bad Debt Expense	Despite London Hydro's best collection efforts, bad debt expenses continue to rise. The economy, price increases, TOU, as well as regulations impacting collection practices are continuing to increase bad debts.	295,000	(320,000)	200,000	-	175,000
Year over Year and Total Change - 2009 to 2013		**391,752**	**(310,834)**	**207,810**	**2,500**	**291,228**

Table 4-13 - Summary of Cost Drivers: Non-Labour *Cont'd*.

		Annual Change				Total Change
Cost Drivers: Non Labour	**Description**	**2009 Actual to 2010 Actual**	**2010 Actual to 2011 Actual**	**2011 Actual to 2012 BRIDGE**	**2012 BRIDGE to 2013 TEST**	**2009 Actual to 2013 TEST**
		$	**$**	**$**	**$**	**$**
SUCCESSION PLANNING, SKILL UPGRADE AND SUSTAINMENT						
Employee Training and Development	The Strategic plan outlines the importance of skilled resources, and training programs must respond to changes in technology, and new skill development. The aging workforce will result in continued high turn-over in future years.	(26,844)	216,658	3,851	(35,400)	158,265
Year over Year and Total Change - 2009 to 2013		**(26,844)**	**216,658**	**3,851**	**(35,400)**	**158,265**
WEATHER AND ENVIRONMENTAL ISSUES						
Snow Removal	Year to year fluctuations impact comparability of prior year actuals to future year forecasts. Test year forecast based on historical averages, although fluctuates from 2009 Actual	67,335	(29,401)	(4,768)	-	33,166
Operating & Maintenance Materials and Supplies	Materials related to storm damage and cycle maintenance programs impact total cost year on year.	69,231	(59,929)	135,125	36,577	181,004
Environmental Assessments and Remediation	Deferrals in programs from prior years are no longer possible. New ongoing assessments and remediation is required	(6,892)	4,609	53,667	-	51,383
Year over Year and Total Change - 2009 to 2013		**129,673**	**(84,721)**	**184,023**	**36,577**	**265,553**

Table 4-13 - Summary of Cost Drivers: Non-Labour *Cont'd.*

		Annual Change				Total Change
Cost Drivers: Non Labour	**Description**	**2009 Actual to 2010 Actual**	**2010 Actual to 2011 Actual**	**2011 Actual to 2012 BRIDGE**	**2012 BRIDGE to 2013 TEST**	**2009 Actual to 2013 TEST**
		$	**$**	**$**	**$**	**$**
OUTSOURCING OPPORTUNITIES / CUSTOMER DEMAND						
Plant Locates	Positioning London Hydro to take advantage of amalgamation of plant locate services and future efficiencies. The internal labour plan reflects reduced headcount requirement for this activity. Locates completed by the service provider continue to increase from the 2009 level.	132,017	28,440	23,406	20,000	203,863
Year over Year and Total Change - 2009 to 2013		**132,017**	**28,440**	**23,406**	**20,000**	**203,863**
CAPITAL INVESTMENT - IMPACT TO OM&A						
Depreciation (part of Fleet overhead)	Since 2009 London Hydro has invested in the fleet in order to reduce maintenance cost, down time, provide efficient, safe and reliable equipment. Approximately 40% of fleet costs remain in OM&A	95,157	224,299	148,270	202,000	669,726
Standby Generator	New investment to provide on-going power supply for emergency situations. Also a safety cost driver	11,272	8,453	(2,309)	1,500	18,916
HVAC Expense	Costs for maintaining the HVAC system were increasing significantly. Replacement of the systems in 2010 and 2011 have resulted in lower on-going cost in 2012.	76,165	5,284	(77,886)	5,000	8,563
Lease Cost / Vehicle Parts & Auto Body Repair	No longer leasing and contracted auto body repair has declined	(190,020)	58,578	16,323	20,000	(95,119)
Year over Year and Total Change - 2009 to 2013		**(7,426)**	**296,613**	**84,399**	**228,500**	**602,086**

Table 4-13 - Summary of Cost Drivers: Non-Labour *Cont'd*.

		Annual Change				Total Change
Cost Drivers: Non Labour	**Description**	**2009 Actual to 2010 Actual**	**2010 Actual to 2011 Actual**	**2011 Actual to 2012 BRIDGE**	**2012 BRIDGE to 2013 TEST**	**2009 Actual to 2013 TEST**
		$	**$**	**$**	**$**	**$**
CONTRACT COST / RENEGOTIATIONS / ALTERNATE SERVICE PROVIDERS						
Photocopier Expense	Competition in market results in negotiations with a new service provider.	(2,909)	(19,013)	1,971	1,700	(18,251)
Telephone Expense	Competition in market results in negotiations with a new service provider.	(8,142)	(39,047)	20,363	200	(26,626)
Insurance Claims Expense	By changing insurance coverage and deductibles, eliminated this cost while maintaining insurance premiums within normal inflationary increases	(35,266)	(1,680)	894	-	(36,052)
Facility Maintenance Contracts and Expense	Contracts such as janitorial, landscape, security, has been renegotiated since 2009	68,057	121,586	44,240	26,000	259,883
Software Mtce - Financial Systems	Issued an RFP for Financial systems support (JDEdwards), resulting in awarding contract at lower price	(584)	(13,662)	(15,157)	1,100	(28,303)
Payment Processing Fees	Faced with 110% increases from service provider this previously outsourced activity was brought in-house. As volumes of lockbox mail continue to decline London Hydro will be able to reduce hours and maintain lower unit processing costs	(3,945)	(6,182)	(33,768)	(2,000)	(45,895)
Fuel	Price increases of 33.6% experienced over the 2009 - 2013 period.	13,072	54,341	8,154	10,000	85,567
Postage	Price increases of 17.5% experienced over the 2009 Actual - 2013 Test period. This price is non-controllable	88,746	80,977	(9,174)	35,000	195,549
Year over Year and Total Change - 2009 to 2013		**119,029**	**177,320**	**17,524**	**72,000**	**385,873**
OTHER COST VARIANCES						
Year over Year and Total Change - 2009 to 2013		**121**	**147,199**	**244,099**	**120,100**	**511,519**
TOTAL ANNUAL CHANGE: NON LABOUR:		1,428,666	676,993	912,234	455,477	3,473,369

Table 4-14 – Summary of Cost Drivers: Cost Recoveries

Note: Costs are presented in CGAAP, no MIFRS impacts	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST
TOTAL Cost Recoveries in OM&A - 2009 ACTUALS to 2013 TEST	**$ (3,610,172)**	**$ (3,815,956)**	**$ (4,137,801)**	**$ (4,258,200)**	**$ (4,678,200)**
Year over Year Change ($)		$ (205,784)	$ (321,845)	$ (120,399)	$ (420,000)
Cumulative Change ($)					$ (1,068,028)
Year over Year Change (%)		5.7%	8.4%	2.9%	9.9%
Cumulative Change (%)					29.6%

		Annual Change				Total Change
Cost Drivers: Cost Recoveries	**Description**	**2009 Actual to 2010 Actual**	**2010 Actual to 2011 Actual**	**2011 Actual to 2012 BRIDGE**	**2012 BRIDGE to 2013 TEST**	**2009 Actual to 2013 TEST**
		$	**$**	**$**	**$**	**$**
<u>CONTRACT RENEGOTIATIONS</u> Provision of Water Billing Services to the City of London	Cost of Service study results in a renegotiation of existing Service Level Agreement with the Affiliate. Details of the independent study are located in the Exhibit 4 Appendices	-	(312,989)	(212,011)	(400,000)	(925,000)
<u>ECONOMIC - REGULATORY COMPLIANCE</u> Collection fees	Collection activity is significantly higher than in 2009. Collection fees are charged to the customer to offset cost.	(167,383)	(10,732)	24,100	(19,000)	(173,015)
<u>OTHER</u> Other cost recoveries	Other miscellaneous cost recoveries, include electric meter sealing, and other non-recurring activities. Apprentice Tax Credits are excluded in 2012 and 2013 as part of PILS calculation.	(38,401)	1,876	67,512	(1,000)	29,987
TOTAL ANNUAL CHANGE - COST RECOVERIES		**(205,784)**	**(321,845)**	**(120,399)**	**(420,000)**	**(1,068,028)**

OM&A Cost per Customer and per Full Time Equivalent ("FTE")

The following, Table 4-15, is provided in accordance with the Filing Requirements and discloses the OM&A Cost per Customer and OM&A Cost per Full Time Equivalent ("FTE").

Customer numbers for the historical years are consistent with the OEB Annual Yearbook for 2009 through 2011 in which the OM&A per customer is calculated for London Hydro and all other LDCs based on the customer numbers at the end of each year. This is in accordance with the Reporting and Record Keeping Requirements ("RRR") *2.1.5 Performance Based Regulation Statistics*. The 2012 and 2013 forecasts are based on the forecasted customer numbers at the end of those years.

Full Time Equivalents (FTEs) from Table 4-45, on Page 96 are used for the following calculations. The definition of FTE was previously discussed on Page 4.

Table 4-15 - Recoverable OM&A Cost per Customer and per FTE

(OEB Appendix 2-L)

	2009 Board Approved	2009 Actuals	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year	2012 Bridge Year	2013 Test Year
	CGAAP						MIFRS	
Number of Customers *(Note 1)*	145,919	145,298	146,973	148,331	149,785	151,747	149,785	151,747
Total Recoverable OM&A from Appendix 2-I *(Note 2)*	$28,291,663	$27,844,217	$30,299,382	$30,876,581	$33,103,186	$33,508,563	$33,430,886	$33,844,563
OM&A cost per customer	$ 193.89	$ 191.64	$ 206.16	$ 208.16	$ 221.00	$ 220.82	$ 223.19	$ 223.03
Number of FTEEs	278.9	273.0	282.1	290.8	323.7	319.5	323.7	319.5
Customers/FTEEs	523	532	521	510	463	475	463	475
OM&A Cost per FTEE	$ 101,440	$ 102,001	$ 107,393	$ 106,178	$ 102,278	$ 104,882	$ 103,291	$ 105,934

Note 1 - Sourced from the OEB Annual Yearbook for all historical years, the 2012 and 2013 forecasts use the customer numbers expected as at Dec 31st.

Note 2 - See Table 4-44

Regulatory Costs:

In accordance with the Filing Requirements, Table 4-16, on Page 31 (OEB Appendix 2-M) provides a breakdown of the actual and anticipated regulatory costs including OEB cost assessments and the expenses for the current application such as legal, consultant fees, and costs awards, among others. Detail associated with the anticipated cost for the preparation and review of this Application is also provided.

The anticipated costs related to this Application are $362,182 and includes the cost for two Board directed studies that were required to be completed and filed with this Application. These studies are related to a lead lag study and the cost of service for the City of London water. The lead lag study is provided in the Appendices in Exhibit 2 (Appendix 2-J). The Navigant Cost of Service Study, dated April 5, 2012, has been applied to the Board Secretary for consideration under the Board's Practice Direction on Confidential Filings (the "Practice Direction"). Cost forecasts are based on the actual costs incurred for the 2009 rebasing year, the additional filing requirements, and anticipated rate increases for legal, consultant, and intervenors. London Hydro has not included any costs related to technical or settlement conferences at this time.

London Hydro proposes that these costs be amortized over 4 years, and therefore has included $90,546 in the total OM&A costs. For further information related to the costs to prepare this application see the section entitled: *"Variance Analyses"*, on Page 34 of this Exhibit.

Table 4-16 - Rate Application Cost Schedule

(OEB Appendix 2-M)

	One-Time Cost Related to this Cost of Service Application	2011	2012 Bridge Year	2013 Test Year	Total
4	Expert Witness costs for regulatory	$ -	$ -	$ -	$ -
5	Legal costs for regulatory matters		87,500	67,500	155,000
6	Consultants' costs for regulatory	53,302	53,880	-	107,182
7	Operating expenses associated with staff resources allocated to regulatory matters	-	-	-	-
8	Operating expenses associated with other resources allocated to regulatory matters [1]	-	-	-	-
11	Intervenor costs	-	-	100,000	100,000
	TOTAL	$ 53,302	$ 141,380	$ 167,500	$ 362,182
	Recover over 4 years, therefore Include 1/4 in 2013 Test Year				$ 90,546

Table 4-17 - Regulatory Cost Schedule

(OEB Appendix 2-M)

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost	Last Rebasing Year (2009 Board Approved)	Most Current Actuals Year 2011	2012 Bridge Year	Annual % Change	2013 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 360,570	$ 375,604	$ 384,548	2.38%	$ 396,131	3.01%
2	OEB Section 30 Costs (Applicant-originated)	5655		On-Going	22,872	16,754	20,453	22.07%	21,069	3.01%
3	OEB Section 30 Costs (OEB-initiated)			On-Going						
4	Expert Witness costs for regulatory matters			One-Time						
5	Legal costs for regulatory matters	5655		One-Time	151,900		87,500		67,500	-22.86%
6	Consultants' costs for regulatory matters	5655		One-Time		53,302	53,880	1.08%		-100.00%
7	Operating expenses associated with staff resources allocated to regulatory matters									
8	Operating expenses associated with other resources allocated to regulatory matters									
9	Other regulatory agency fees or assessments	5655		On-Going	800	800		-100.00%		
10	Any other costs for regulatory matters (please define)			On-Going						
11	Intervenor costs	5655		One-Time	94,637	(30,000)		-100.00%	100,000	
12	Sub-total - Ongoing Costs		$ -		$ 384,242	$ 393,158	$ 405,000	3.01%	$ 417,200	3.01%
13	Sub-total - One-time Costs		$ -		$ 246,537	$ 23,302	$ 141,380	506.73%	$ 167,500	18.48%
14	Total		$ -		$ 630,780	$ 416,460	$ 546,380	31.20%	$ 584,700	7.01%

One-Time Costs:

One-time costs related to the roll-out of TOU billing in 2012 total $430,400. These costs will be recovered through the Smart Meter Incremental Rate Rider ("SMIRR") and are not included in the proposed 2013 Test Year. No other one-time costs have been identified.

Low-Income Energy Assistance Programs ("LEAP"):

Only donations qualifying for recovery have been included in this submission. In 2009, the Board approved a donation to the Low-income Energy Assistance Programs ("LEAP") of $50,000. London Hydro's actual contribution in 2009 and throughout the years under review has been $100,000. London Hydro will continue this commitment to emergency financial assistance and is in full compliance with the March 2009 Board policy report for LEAP of 0.12% of approved distribution revenue requirement. Table 4-18 below compares the minimum required contribution and London Hydro's annual contribution (2009 Actual to proposed 2013 Test Year).

Table 4-18 - Contributions to LEAP

	2009	2010	2011	2012	2013
Distribution Revenue Requirement	$ 58,087,982	$ 58,192,541	$ 58,297,287	$ 58,810,303	$66,706,133
Minimum LEAP Contribution	$ 69,706	$ 69,831	$ 69,957	$ 70,572	$ 80,047
London Hydro's Annual Contribution	**$ 100,000**	**$ 100,000**	**$ 100,000**	**$ 100,000**	**$ 100,000**

Charitable Donations:

The following, Table 4-19 below, lists charitable donations paid by year from the last Board approved rebasing application in 2009 until and including the proposed 2013 Test Year. These charitable donations do not include those made under LEAP as discussed above. London Hydro has excluded these charitable donations for the purpose of setting rates, and will not seek recovery for these amounts.

London Hydro also confirms that no political contributions have been included for recovery.

Table 4-19 - Charitable Donations (Excluding LEAP)

Donations (Excluding LEAP)	
YEAR	AMOUNT ($)
2009	3,291
2010	7,252
2011	5,742
2012	14,500
2013	14,500

VARIANCE ANALYSES

Historical Cost Review (2009 – 2011, CGAAP):

Operating and Maintenance

OM&A for the 2009 Cost of Service Application as submitted was $28,169,400. The Board Decision included total net reductions to OM&A of $409,637. London Hydro has also restated the 2009 Approved amounts for the accounting change related to V&E in the amount of $481,900. Therefore the 2009 Board Approved Cost of Service OM&A including the restatement is $28,241,663. London Hydro managed to this Board approved total OM&A to within 1.8% or $497,446 by reducing among others, targeted spending for labour, and corporate training and employee expense by $225,000 and $125,000 respectively.

In 2010, OM&A costs increased $2,455,165 or 8.8% over the 2009 Actuals. This was a year of significant business change.

The year 2010 was the first full year with the new customer information and billing system ("CIS"), after a mid-year go live date in 2009, which impacted the need for skilled resources to support this new technology. The related maintenance fees for both hardware and software, and both internal labour and external contracted labour were major cost drivers in the first full year of operation. The new CIS was implemented to make ready for TOU billing.

Also in 2010 the depressed economy and regulatory direction related to collection practices impacted bad debt expense which increased $295,000 over the 2009 Actuals and $585,000 over the 2009 Board Approved amount despite all attempts to collect the outstanding debts.

In 2010 total benefits costs which include health care, and pension costs among others increased by $577,398 significantly impacting total OM&A in that year as approximately 78% of these costs are related to OM&A activities.

In 2011, the overall OM&A cost increases were more moderate, with an increase of $577,199 or 1.9% over the 2010 Actual results.

Negotiated wages increases of 2.5%, and increased spending primarily related to corporate training of $295,801 or 40.0% were key cost drivers increasing OM&A in 2011. In contrast to these cost increases, bad debt levels showed some improvement over the 2010 levels. The slowly recovering economy and continual improvements to collection practices were factors impacting this result.

Also, in 2011 London Hydro incurred significant costs related to the use of external contracted labour to support the CIS and other new technology and information systems. The use of external contractors impacts cost, flexibility, consistency, and stability and results in a high dependency on external contractors. A shortage of available skilled resources in the market place contributed to this situation. London Hydro began to address the need for change in the mix of internal staff and external contractors to reduce this dependency with increases to internal headcount and investing in additional specialized training.

Table 4-8, on Page 16 provides detailed cost information for the historical years of 2009 through 2011.

Amortization

As previously discussed in the "*Manager's Summary"* section of this Exhibit, in 2010, London Hydro implemented an accounting change to include vehicle and equipment depreciation in overhead rates used to allocate the cost of the fleet to operating, capital, and billable activities. Prior to that vehicle and equipment amortization was included in amortization expense. Historical actuals are restated for comparability purposes. Actual amortization expense in 2009 was lower than the Board approved amount by $359,605 or 2.3%, mainly due to the timing of completion of capital projects.

Increases in actual amortization expense from 2009 to 2010 and 2010 to 2011 are 5.8% and 5.7% respectively.

Major Cost Categories Variance Review:

Exhibit 4 evidence provides a historical cost summary by the major OEB cost categories, with year over year, average, and cumulative % change, as well, by major cost categories. Detailed variances by major cost category and by OEB USoA are provided in accordance with the Filing Requirements.

Major cost category variances in OM&A are being provided for:

- Labour and Benefits
- Purchased Services
- Materials and Supplies
- Bad Debt
- Property Tax and Insurance
- Facilities Maintenance and Repair
- Office Equipment Services and Maintenance
- Postage
- Fleet Operations and Maintenance
- Corporate Training and Employee Expense
- Rent, Regulatory and Other Expense
- Studies and Special Projects
- Allocations of fleet and material management costs to OM&A, capital, and billable services
- Cost Recoveries

Labour and Benefits:

Overview:

The following discussion reviews total base salaries and wages, premium pays, benefits, and deployment of resources to OM&A, capital, billable and other activities.

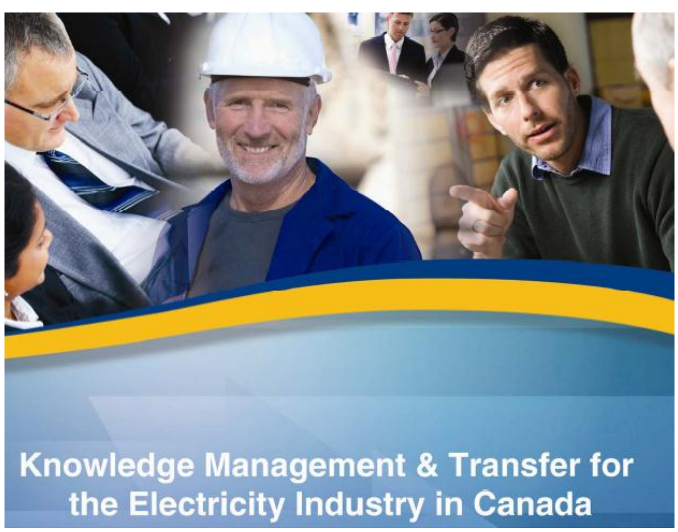
As previously outlined in the "*Budget Overview - Capital and Operating"* discussion in Exhibit 1, beginning on Page 34, each department prepares an overall labour plan detailed by employee and position. The labour plan also includes the forecasted deployment of resources to OM&A, capital, billable, and other activities. The strategic plan provided in Appendix 1A provides the corporate objectives underpinning the budget development.

The significant cost drivers impacting total labour and benefits are, among others:

- Negotiated wage settlements
- Change in employee complement (headcount, skill set, wage level progression)
- Benefit cost increases
- Shift in mix of internal and external resources used to support operating and capital plans
- Deployment of resources to capital, billable, and other activities

In 2010, the Electricity Sector Council with funding from the Government of Canada's Sector Council Program completed a report entitled "*Knowledge Management & Transfer for the Electricity Industry in Canada"*. The report identifies resourcing issues that are facing the electricity industry as a whole and provides strategies to identify and implement knowledge management and knowledge transfer plans. Within the report key business drivers are identified and include: complexity of the sector, emerging technologies, the need for specialized knowledge, changing demographics (the aging workforce and knowledge transfer), developing the next generation of electricity workers (human capital development).

The link to the on-line report is provided as reference as it speaks well to the current situation facing London Hydro, and other LDCs in the province. www.brightfutures.ca



Appendix 4A provides some key excerpts from this report.

Utilizing inflation factors to identify appropriate labour cost increases in OM&A is, in London Hydro's opinion, not appropriate under the current business environment.

The aging workforce continues to challenge the LDC community. Succession planning is critical to ensure that skilled resources are available as the current workforce retires. New and emerging technology and industry complexity are changing the profile of skills required to effectively operate the business. In London Hydro's previous cost of service application for the last rebasing year of 2009, this issue was identified and will still impact labour planning into the future.

Total labour costs (including premium pay and benefits) is $33,387,600 for the proposed 2013 Test Year. This is a cumulative increase over the 2009 Actuals of $7,704,832 or 30.0%.

London Hydro expects to utilize labour in capital, billable and other activities. Deployment of resources to these activities is forecasted to be $10,303,300 for the proposed 2013 Test Year. This is a cumulative increase over the 2009 Actuals of $3,556,670 or 52.7%. In 2009 26.3% of total internal labour was allocated to capital, billable, and other activities. In the proposed 2013 Test Year it is forecasted to be 30.9%.

London Hydro uses contracted labour to augment its internal labour complement and is moving to a more appropriate mix of internal labour and external contracted labour. This provides consistency, improved knowledge base, flexibility, and lowers cost. As part of the long-term plan, London Hydro has established which significant projects will be undertaken and the skill set that will be required. London Hydro would then determine if the skill set exists in-house. If the skill set does not exist then an analysis is completed to determine from both a short-term and long-term perspective whether the project and maintenance should be performed by a third party contractor or whether additional training of internal staff is required.

Although this is the strategy adopted by London Hydro, there have been situations where resources with the appropriate skill set were not available and external consultants were required to be utilized. As an example, Information Services has increased headcount and as knowledge is transferred and the CIS system matures, internal labour headcount increases are being offset with lower reliance on external contractors.

External contracted services are discussed further in, *Purchased Services* on Page 57 of this Exhibit.

Table 4-20, below summarizes the cumulative change in total labour and deployment over the period reviewed in this application (2009 Actual to 2013 Test) with the net impact to OM&A.

Table 4-20 - Summary of Cumulative Changes to Labour, Benefits, and Deployment

Summary of Cumulative Changes to Labour & Benefits in OM&A	Cumulative VARIANCE 2009 ACTUAL - 2013 TEST	
Base Labour	$ 5,629,472	29.5%
Premium Pays	(33,616)	-2.7%
Benefit Cost	2,108,976	39.2%
TOTAL Salaries, Wages, & Benefits	7,704,832	30.0%
Allocation to Capital, Billable, Other	(3,556,670)	52.7%
Net Labour & Benefits in OM&A	**$ 4,148,162**	**21.9%**

The net of total labour cost less the deployment to capital, billable and other activities is the labour and benefit costs remaining in OM&A. Labour required for the OM&A programs is $23,084,300 for the proposed 2013 Test Year, an increase of $4,148,162 or 21.9% over the 2009 Actuals. The average annual increase over the four years (2009 - 2013) is 5.5%.

Table 4-21, on Page 43 provides full details by year of all elements of labour: base wages and salaries, premium pays, benefit cost as well as historic deployment to capital, billable, and other activities.

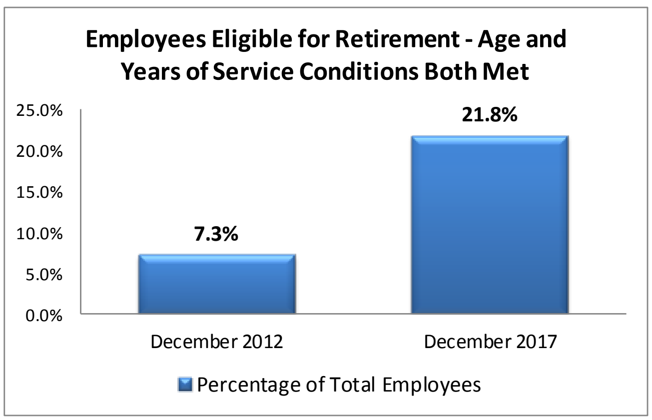
Base Labour:

Base labour is defined as salaries and wages, excluding premium pay and benefits. It is impacted by changes in total headcount, knowledge and skill requirements, wage progression steps, and wage increases, among others.

The following statistics on employee demographics are provided as evidence of the on-going issue of an aging workforce, which will have cost impacts well into the future. London Hydro is addressing this issue through supervisory, technical, and specialized industry training as well as mentoring, and the hiring of new apprentice positions.

A study completed by London Hydro in 2012 indicates that by December 31, 2012, 7.3% of the current workforce will have both the age and years of service that are required to be eligible for retirement. By the end of 2017, this will increase to 21.8% as shown in Chart 4-1, below.

Chart 4-1 - Employees Eligible for Retirement



Age demographics will change significantly as is shown in Chart 4-2, on Page 41 between December 2012 and December 2017.

Statistics show that the percentage of current employees who are 55 years of age or older will increase from 23.2% in 2012 to 45.7% in 2017.

The average age of employees will rise from the current average of 46.3 years to 52.0 years in 2017.

These statistics and trends are provided to illustrate the anticipated impact of retirements. Although it is impossible to predict exactly when an employee will retire, these statistics are used to plan for the future. The current shortage of skilled resources available means that London Hydro must invest now for the future.

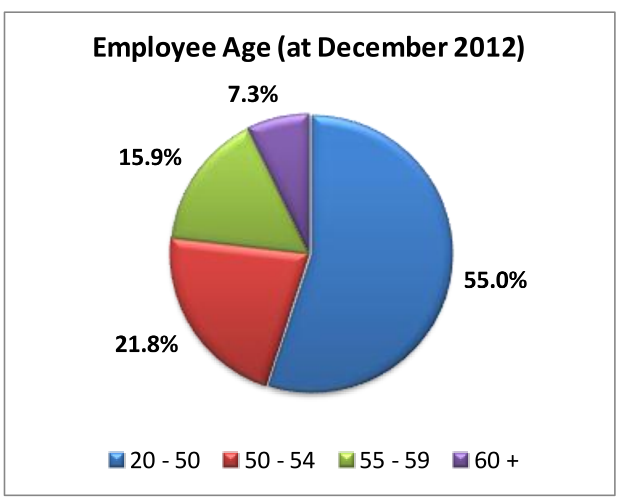
The Company's workforce continues to age and retire at an extremely rapid pace. Since 2009, London Hydro has hired 22 apprentices. Many of these apprentices have been hired based on the demographics previously discussed where 21.8% of employees will be eligible to retire within the next five years.

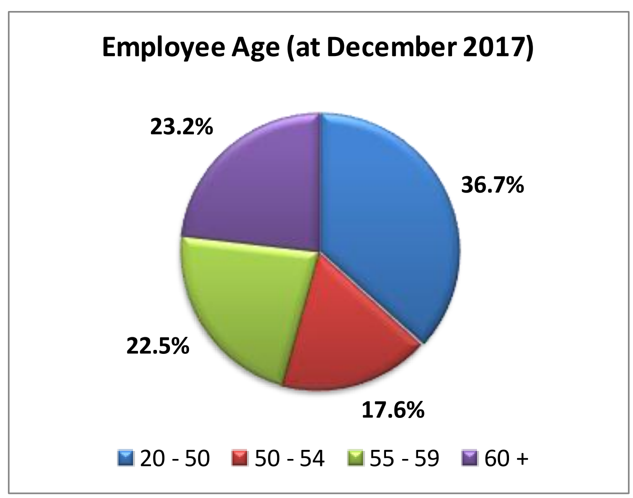
Although the length of the apprenticeship program is four years, it often takes an additional 2-3 years of on-the-job training to be fully competent, depending on the trade. London Hydro continues to hire apprentices and other staff now to deal with the current and future turnover impacting the Company.

Changes in technology and skill requirements are also key cost drivers related to labour. Through attrition some redundant positions are being replaced to meet the new technical demand, while in other areas new information technology positions are required to support complex information systems.

The implementation of TOU billing is adding a new dimension of complexity and is impacting the resources required to respond to customer inquiries and to support the billing function. The complexity of the bill is requiring more time to review with the customer.

Chart 4-2 - Age Demographics 2012 and 2017





The Confidential Appendix (Table - C1) has been applied to the Board Secretary for consideration under the Board's Practice Direction on Confidential Filings (the "Practice Direction"), provides actual negotiated wage increases for 2009 to 2012, inclusive as well as the forecasted increase for 2013. The current collective agreement with the Power Workers' Union expires as at December 31, 2012. The current industry shortage of skilled resources, together with higher demand due to an aging workforce is impacting wage settlements across the province. London Hydro will continue to pursue the best possible outcome during the upcoming negotiations, scheduled to begin in the fall of 2012.

Table - C2 has been applied to the Board Secretary for consideration under the Board's Practice Direction on Confidential Filings (the "Practice Direction"). The Table provides wage increases negotiated at other LDCs as evidence that the forecasted wage increase for 2013 is within current trends and the industry norm.

The proposed 2013 Test Year labour plan is provided in Table 4-22, on Page 44 and is compared to the 2009 Actuals. Changes in labour are grouped consistent with the organizational structure as presented in Exhibit 1, on Page 25. The notes provided in Table 4-22, detail the functions under each department, being Engineering and Operations, Corporate Services, Financial Services, and Executive Services.

Table 4-21 - Summary of Year over Year Changes to Labour & Benefits in OM&A

Summary of Changes to Labour & Benefits in OM&A

	2009 TEST as Submitted	Board Decision Adj	2009 Board Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST
Base Labour	$ 19,192,700	$ (175,000)	$ 19,017,700	$ 19,067,028	$ 20,115,775	$ 21,084,429	$ 23,905,200	$ 24,696,500
Premium Pays	1,060,300		1,060,300	1,240,116	1,244,682	1,444,954	1,193,600	1,206,500
Benefit Cost	5,613,300	(50,000)	5,563,300	5,375,624	5,953,022	6,270,801	7,065,400	7,484,600
TOTAL Salaries, Wages, & Benefits	25,866,300	(225,000)	25,641,300	25,682,768	27,313,479	28,800,185	32,164,200	33,387,600
Allocation to Capital and Billable	(6,472,600)	-	(6,472,600)	(6,746,630)	(6,913,533)	(7,931,964)	(9,615,400)	(10,303,300)
Net Labour & Benefits in OM&A	$ 19,393,700	$ (225,000)	$ 19,168,700	$ 18,936,138	$ 20,399,946	$ 20,868,220	$ 22,548,800	$ 23,084,300

	2009 Actual to 2009 Board Approved	2010 Actual to 2009 Actual	2011 Actual to 2010 Actual	2012 BRIDGE to 2011 Actual	2013 TEST to 2012 BRIDGE
VARIANCES ($)					
Base Labour	$ 49,328	$ 1,048,747	$ 968,655	$ 2,820,771	$ 791,300
Premium Pays	179,816	4,566	200,271	(251,354)	12,900
Benefit Cost	(187,676)	577,398	317,779	794,599	419,200
TOTAL Salaries, Wages, & Benefits	41,468	1,630,711	1,486,705	3,364,015	1,223,400
Allocation to Capital and Billable	(274,030)	(166,903)	(1,018,431)	(1,683,436)	(687,900)
Net Labour & Benefits in OM&A	$ (232,562)	$ 1,463,809	$ 468,274	$ 1,680,580	$ 535,500
VARIANCES (%)					
Base Labour	*0.3%*	*5.5%*	*4.8%*	*13.4%*	*3.3%*
Premium Pays	*17.0%*	*0.4%*	*16.1%*	*-17.4%*	*1.1%*
Benefit Cost	*-3.4%*	*10.7%*	*5.3%*	*12.7%*	*5.9%*
TOTAL Salaries, Wages, & Benefits	*0.2%*	*6.3%*	*5.4%*	*11.7%*	*3.8%*
Allocation to Capital and Billable	*4.2%*	*2.5%*	*14.7%*	*21.2%*	*7.2%*
Net Labour & Benefits in OM&A	*-1.2%*	*7.7%*	*2.3%*	*8.1%*	*2.4%*

	2009 TEST as Submitted	Board Decision Adj	2009 Board Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST
Allocation as % ot TOTAL Salaries, Wages, & Benefits			*25.2%*	*26.3%*	*25.3%*	*27.5%*	*29.9%*	*30.9%*
Labour in OM&A as % of TOTAL Salaries, Wages, & Benefits			*74.8%*	*73.7%*	*74.7%*	*72.5%*	*70.1%*	*69.1%*

Table 4-22 - Labour Plan (2009 Actual and 2013 Test Year)

2013 Labour Plan - Summary

DEPARTMENT (see Notes)		TOTAL HEADCOUNT (FTE)			ALLOCATIONS (FTE)					COST ($)				
		FT	PT	TOTAL	CAPITAL	OPA	OTHER	TOTAL	OM&A	Labour	Benefits	Premium Pays	Allocations to Capital / Billable	NET OM&A
Engineering and Operations	*(1)*	162.0	11.3	173.3	(69.7)	-	(2.6)	(72.3)	101.0	$ 13,064,800	$ 4,077,700	$ 1,148,500	$ (7,074,800)	$ 11,216,200
Corporate Services	*(2)*	77.0	5.3	82.3	(8.9)	-	(1.2)	(10.1)	72.2	5,862,100	1,764,900	30,000	(748,500)	6,908,500
Financial Services	*(3)*	15.0	2.0	17.0	-	-	(0.5)	(0.5)	16.5	1,415,400	430,900	-	(45,500)	1,800,800
Executive Services	*(4)*	34.0	12.9	46.9	(8.4)	(12.7)	0.5	(20.7)	26.2	4,354,200	1,211,100	28,000	(2,434,500)	3,158,800
TOTAL	*(5)*	**288.0**	**31.5**	**319.5**	**(87.1)**	**(12.7)**	**(3.8)**	**(103.6)**	**215.9**	**$ 24,696,500**	**$ 7,484,600**	**$ 1,206,500**	**$(10,303,300)**	**$ 23,084,300**

2009 Actual Labour - Summary

DEPARTMENT (see Notes)		TOTAL HEADCOUNT (FTE)			ALLOCATIONS (FTE)					COST ($)				
		FT	PT	TOTAL	CAPITAL	OPA	OTHER	TOTAL	OM&A	Labour	Benefits	Premium Pays	Allocations to Capital / Billable	NET OM&A
Engineering and Operations	*(1)*	145.5	7.5	153.0	(60.5)	-	(2.3)	(62.8)	90.2	$ 10,616,035	$ 3,073,695	$ 991,887	$ (5,707,635)	$ 8,973,982
Corporate Services	*(2)*	66.4	12.5	78.9	(4.5)		(0.1)	(4.6)	74.3	5,393,410	1,463,452	202,139	(576,539)	6,482,463
Financial Services	*(3)*	13.5	1.3	14.8	-	-	(0.1)	(0.1)	14.7	1,045,393	283,145	32,019	83,781	1,444,338
Executive Services	*(4)*	23.6	2.7	26.3	(4.2)	(2.1)		(6.3)	20.0	2,012,189	555,332	14,072	(546,237)	2,035,356
TOTAL		**249.0**	**24.0**	**273.0**	**(69.2)**	**(2.1)**	**(2.5)**	**(73.8)**	**199.2**	**$ 19,067,028**	**$ 5,375,624**	**$ 1,240,116**	**$ (6,746,630)**	**$ 18,936,138**

Note 1 *Includes Engineering, System Planning, Network and Substations, Overhead and Underground, Control Centre, Dispatch and Admininstration, Purchasing and Materials Management etc.*
Note 2 *Includes Customer Services, Metering Services, Corporate Communications, Facilities, and Human Resources*
Note 3 *Includes Finance, Regulatory, Risk Management*
Note 4 *Includes Information System, Project Management Office, Conservation and Demand, Executive Office*
Note 5 *Total labour plan includes incremental TOU/Smart Meter positions $232,000. (Table 4-5). Table 4-10 - $22,852,300 + $232,000 =23,084,300 (above)*

Engineering and Operations:

Engineering and Operations will increase the complement of part time, or temporary staff in 2013, and change the mix of internal and external contracted labour used to provide more flexibility. Using part time and temporary staff provides an opportunity to assess potential candidates for the future as well as provide coverage when full time staff is engaged in other activities such as capital projects.

The mix of internal labour and external contracted services utilized has been evolving and the portion of total internal labour allocated to capital and billing services is increasing. Total headcount will increase by 20.3 FTEs over the 2009 to 2013 period; however, the increase in headcount in OM&A is 10.8 FTEs over this same time period.

As with all other departments, Engineering and Operations has faced and will continue to face some significant challenges since the last rebasing year in 2009. Succession planning, a shortage of skilled resources, new technology and complexity, out-sourcing opportunities, change in skill set requirements, the need for flexibility, and a changing mix between internal and external resources are all impacting the labour plan.

In order to deal with these issues the Engineering and Operations' labour plan has changed from the 2009 Actuals. Over the period since 2009 the labour complement is changing with:

- a new Learner Systems Operator, and a Co-Op System Operator
- three new Apprentice Power Line Maintainers
- the elimination of one Plant Locate position
- a new Instrumentation and Control ("I&C") position
- three new Geographic Information System ("GIS") positions
- the elimination of one RBD Operator position
- filling open construction worker positions and increasing the complement by three
- two new Secondary Cable Servicer positions
- the elimination of an Electric Maintenance Helper position
- a new Executive Assistant
- a new Operations Service Representative position
- two new Distribution and one Assistant Distribution Engineer positions

- a new Contract Logistics Analyst
- other position reclassifications and departmental as well as corporate reorganizations

Corporate Services:

This department includes Customer Services, Corporate Communication, Human Resources, Facilities Management, and Metering Services. The total headcount will increase by 3.4 FTE over the 2009 to 2013 period; however, the decrease in headcount in OM&A is 2.1 FTEs over this same time period.

Technology, complexity, and the impact to the customer are the key drivers changing resources in this area.

The evolution to TOU billing and wireless meter interrogation has changed the resource profile significantly. Positions related to the traditional method of gathering and verifying meter readings are no longer required, however, new technology and bill complexity require additional information systems, billing and customer support.

Bill complexity and customer information demands have impacted the contact centre resource complement. Additional training time and the need for a stable and knowledgeable workforce makes the use of part-time or temporary labour impractical. On average the duration of a customer call received in the contact centre has increased from 5:21 minutes in 2009 to 7:39 minutes in 2012. Although education will, over time, assist the customers, the resources will continue to be needed to meet the current mandated service response standards set by the regulator. Customer inquiries are also now being increasingly handled on-line through email contact.

In order to deal with these issues the Corporate Services' labour plan has changed from the 2009 Actuals. Over the period since 2009 the labour complement is changing with:

- the elimination of the VP, Customer Services and Strategic Planning
- a new Customer Service Supervisor position
- the elimination of a Meter Reader position
- the elimination of Meter Data Management position
- three new Business Analysts

- three new Billing Support positions
- six new permanent Customer Service Representative (“CSR”) positions
- the elimination of five part-time and temporary CSR FTEs
- a new Corporate Communication Assistant
- other position reclassifications and departmental as well as corporate reorganizations

Financial Services:

Financial Services is responsible for all financial aspects of London Hydro including, but not limited to, financial reporting, budgets, financial systems, payment processing, and regulatory affairs and compliance.

There are four main drivers that are influencing the labour complement in Financial Services: complexity, business process change, regulatory, and accounting standards.

In 2013, London Hydro will adopt IFRS for financial reporting. This will add complexity and increases in financial statement reporting disclosure that will result in additional resource requirements. London Hydro has been preparing for this transition since 2010.

A business process change in the way customer damage claims are handled has changed resource requirement and allowed London Hydro to redeploy resources to other accounting functions. Claims are now handled directly by the insurance company.

Accounting for and compliance with regulatory requirements has become a significant function for Financial Services. London Hydro has identified the importance of this function and has developed knowledgeable resources to ensure accuracy and timely filings in compliance with regulatory direction.

The overall increase in OM&A headcount is 1.8 FTEs over the 2009 Actual level.

In order to deal with these issues the Financial Services’ labour plan has changed from the 2009 Actuals. Over the period since 2009 the labour complement is changing with:

- additional part-time positions for in-house payment processing
- the elimination of a Claims Coordinator position
- two new Accountant positions

- other position reclassifications and departmental as well as corporate reorganizations

<u>Executive Services:</u>

The functions included in this department include the Executive and Board of Directors Office, Information Services and the Project Management Office, and CDM.

It is important to note that all the discussions related to Base Labour and headcount provides information on the total resource complement as well as the headcount included in OM&A activities. Labour related to CDM will be discussed in this section, however, it is fully allocated out and the labour cost of this program is recovered entirely from the OPA. There is no labour in OM&A related to the CDM program.

The new expanded CDM program is one of the key drivers that have increased total headcount in this department.

Other significant technology and system changes, technical complexity, the need for data quality assurance and reliability, and the movement to a more appropriate mix between internal labour and external contracted labour are resulting in changes in resource requirements. The strategic plan (Exhibit 1, Appendix 1A) identifies that technology and information systems are critical for future success.

During the period from the last rebasing year of 2009, the new SAP Customer information and Billing system which was primarily implemented in order to support the TOU billing was put into service in June of 2009. Since that time London Hydro has extensively used external contracted labour to support the system and business requirements. The importance of a stable, more economical, knowledgeable internal staff complement has shifted the system support to internal resources.

Other significant systems implementation such as the new GIS and the future Outage Management System (“OMS”) will require implementation resources and on-going maintenance support.

More information related to future system implementations such as the OMS is provided in the Information Technology Strategic Plan, Exhibit 2, Appendix 2-I.

The overall increase in headcount is 20.6 FTEs over the 2009 Actual level. Allocations to the OPA have increased by 10.6 FTEs, and in conjunction with changing the mix of internal and external resources, allocation to capital projects is increasing by 4.2 FTE over this same time period. This allows for the development of in-house knowledge and improves capital project control and cost while at the same time remaining flexible as capital requirements fluctuate.

The total increase in headcount in OM&A is 6.2 FTEs over the 2009 to 2013 period.

In order to deal with these issues the Executive Services' labour plan has changed from the 2009 Actuals. Over the period since 2009 the labour complement is changing with:

- the creation of a Project Management Office ("PMO") with a new Chief Information Officer ("CIO") and Executive Assistant position
- a contract PMO position
- three new SAP Specialist positions
- new SAP Application Supervisor position
- two additional Business Analyst positions
- a new GIS Specialist position
- new Contract Data Base Administrator position
- creation of a new CDM resource complement with full recovery of cost from the OPA
- other position reclassifications and departmental as well as corporate reorganizations

Benefits:

A comprehensive and competitive benefits package exists which includes medical insurance, life insurance, long term disability insurance, vacation policies, and a company-sponsored retirement plan (OMERS). The plans are designed to address the health and welfare needs of the employee population. The benefit packages are basically consistent across the organization with only minor differences in the packages for the Non-Union and Executive groups.

Total benefit costs have increased $2,108,976 or 39.2% between the 2009 Actual and the proposed 2013 Test Year. All benefits are allocated appropriately to OM&A, capital, billable and other activities, based on labour deployment, using hourly allocation rates. Table 4-23, on Page 52, provides details of total benefit cost.

Statutory benefits, including CPP, EI, EHT, and WSIB, have increased $426,853 or 30.6% for this period.

London Hydro has a pension agreement with OMERS, which is a multi-employer contributory defined benefit plan. Company contributions to the plan are recognized as pension expense in the period that they are incurred. Total pension costs are allocated between OM&A and capital in the same manner as all other benefits as shown in Table 4-24, on Page 53. London Hydro's total contributions to OMERS on behalf of the employees have increased between the 2009 Actuals and the proposed 2013 Test Year by $1,071,337 or 78.0%. This is primarily due to the implementation of higher contribution rates and increases in the full time workforce. In 2010 OMERS announced a three year strategy that would help fund the OMERS plan until the next actuarial filing. The following link to the OMERS website provides information on the contribution increases. Key excerpts are provided below.

http://www.omers.com/corporate/news_article.aspx?newsid=5611

News

OMERS 2013 Contribution Rates and Plan Changes Announced

July 06, 2012

OMERS Sponsors Corporation (SC), which represents active and retired members and employers, approved two plan changes in a meeting on June 28, 2012:

- Contribution rate increases were set for 2013 - the third increase as part of a three-year strategy announced in 2010; and
- A cap on contributory earnings, equal to seven times the CPP earnings limit (Year's Maximum Pensionable Earnings or YMPE).

In addition to setting the contribution rates for 2013, the SC approved a new method for allocating contribution rates in the future. These changes do not affect OMERS retired members, deferred members, or survivors.

As well, the December 31, 2011 valuations for the OMERS Primary Pension Plan (OMERS Plan) and the OMERS Supplemental Plan for Police, Firefighters and Paramedics (Supplemental Plan) will be filed.

Contribution rates

Contribution rate changes for the OMERS Plan are effective with the first full pay in 2013.

		2012	2013
Normal retirement age 65 members	On earnings up to CPP earnings limit*	8.3%	9.0%
	On earnings over CPP earnings limit*	12.8%	14.6%
Normal retirement age 60 members	On earnings up to CPP earnings limit*	9.4%	9.3%
	On earnings over CPP earnings limit*	13.9%	15.9%

**The CPP earnings limit in 2012 is $50,100; the limit in 2013 will be higher. OMERS members pay a lower rate on earnings up to the YMPE because OMERS and the CPP are designed to work together to provide pension benefits. Contributions are tax deductible which lessens the net impact on Plan members.*

In 2010, OMERS announced a three-year plan to increase contribution rates. The contribution rate increases set for 2013, are the third increase.

- A flat 1% contribution rate increase per side was implemented in 2011.
- In 2012, the average increase in contribution rates was 1% per side, but the actual increase in each of the four component rates showed more variation.
- Also in 2012, the SC conducted a comprehensive review of the principles for setting contribution rates, leading to the 2013 rates above.
- The rates for 2013 affect members differently at various earnings levels and normal retirement age groups (65 and 60); however, the increase averages out to be 0.9% for members and employers.
- These rates will provide the OMERS Plan with the total contributions required to fund the OMERS Plan until the next actuarial filing.

Extended health and dental care coverage has remained virtually unchanged, and it is experience rated, meaning that London Hydro's cost is determined by its actual claims. Costs have increased between the 2009 Actuals and the proposed 2013 Test Year by $205,087 or 20.2%

London Hydro provides certain non-pension post-retirement benefits to employees upon retirement. This post-retirement plan is a defined benefit plan funded on a cash basis by contributions from London Hydro. Recognition of these benefits is actuarially determined using the projected benefit method, in accordance with CICA 3461, and is pro-rated on service using management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, and expected health care costs. Total employee future benefit costs are allocated between OM&A and capital as shown in Table 4-23, below.

London Hydro's IFRS transitional adjustment for Pension and Other Post-Employment Benefits represents the difference in the Company's liability under IFRS in comparison to that calculated under CGAAP as at January 1, 2012. This transitional adjustment has no impact on the revenue requirement as filed in this Application. Since IFRS has not yet been fully implemented, this transitional adjustment is being made as a place holder only until such time as transition to IFRS has been completed. Additional information related to this and other transitional issues is summarized in Exhibit 10.

Table 4-23 - Benefit Cost Increases (2009 to 2013)

Benefit Cost Changes 2009 - 2013							
	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Change 2009 Actual - 2013 TEST	
	CGAAP						
STATUTORY							
CPP	$ 592,453	$ 625,721	$ 652,348	$ 744,000	$ 755,400	$ 162,947	*27.5%*
EI - Employer's Portion	247,290	263,655	282,663	359,100	364,600	117,310	*47.4%*
Employer's Health Tax	413,198	434,000	450,927	455,800	462,800	49,603	*12.0%*
WSIB Admin/Premium Exp	141,907	292,692	161,291	230,700	238,900	96,993	*68.4%*
	1,394,847	1,616,068	1,547,230	1,789,600	1,821,700	426,853	*30.6%*
EMPLOYEE FUTURE BENEFIT	816,594	879,886	1,197,516	1,042,600	1,071,600	255,006	*31.2%*
ACTIVE							
OMERS	1,374,363	1,475,067	1,692,245	2,178,700	2,445,700	1,071,337	*78.0%*
EI - Employee Portion	129,094	132,536	139,505	172,400	172,200	43,106	*33.4%*
LTD Insurance	360,170	372,891	398,405	422,800	435,500	75,330	*20.9%*
Life Insurance	121,228	94,615	100,662	106,500	109,700	(11,528)	*-9.5%*
Health and Other Benefits	1,016,913	1,210,114	1,021,299	1,151,200	1,222,000	205,087	*20.2%*
Employee OHIP Premiums	162,414	171,845	173,939	201,600	206,200	43,786	*27.0%*
	3,164,182	3,457,068	3,526,056	4,233,200	4,591,300	1,427,118	*45.1%*
TOTAL BENEFIT COSTS:	**$ 5,375,624**	**$ 5,953,022**	**$ 6,270,801**	**$ 7,065,400**	**$ 7,484,600**	**$ 2,108,976**	***39.2%***

Benefit costs are allocated to OM&A, capital, billable, and other activities using an appropriate overhead rate based on cost and hours worked by activity. Table 4-24, below details the historical Actuals as well as the 2012 Bridge and 2013 proposed Test Year for benefit costs allocated to OM&A activities. Consistent with the base labour allocations, a higher percentage of benefit cost is being allocated to capital, billable, and other activities.

Table 4-24 - Allocation of Benefits Costs

Benefit Cost Allocation							
	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	Change 2009 Actual - 2013 TEST	
	CGAAP						
TOTAL Benefit Cost	$ 5,375,624	$ 5,953,022	$ 6,270,801	$ 7,065,400	$ 7,484,600	$ 2,108,976	*39.2%*
Allocation to Capital and Billable	$ 1,310,393	$ 1,326,911	$ 1,397,518	$ 1,841,459	$ 2,005,267	$ 694,874	*53.0%*
Benefit Cost in OM&A	$ 4,065,230	$ 4,626,111	$ 4,873,283	$ 5,223,941	$ 5,479,333	$ 1,414,103	*34.8%*
Allocation to Capital and Billable (	*24.4%*	*22.3%*	*22.3%*	*26.1%*	*26.8%*	*2%*	
Allocation to OM&A (%)	*75.6%*	*77.7%*	*77.7%*	*73.9%*	*73.2%*	*-2%*	

Premium Pay:

Premium pay includes both planned and emergency overtime, as well as shift and standby pays. It is a significant component of gross pay and totals $1,206,500 in the proposed 2013 Test Year. Total premium pay has decreased $33,316 or 2.7% between the 2009 Actuals and the proposed 2013 Test Year.

Overtime, which is by far the largest component of premium pay, has both controllable and uncontrollable elements. Emergency overtime typically results from severe weather and other uncontrollable events and it has increased 33.3% between 2009 and 2013, while planned overtime, which can be in part controlled by scheduling, has declined 29.9% for the same period.

The proposed 2013 Test Year overtime is $245,873 or 18.1% lower than the 2011 Actual results and $46,796 or 4.0% lower than the 2009 Actuals. With the wage increases factored in, the overall decrease from 2009 Actuals is higher than this comparison of cost indicates. Total overtime hours are expected to decline by 16.1% or approximately 2,893 hours from the 2009 Actuals.

London Hydro continues to implement ways to reduce overtime and the re-organization of resources and outsourcing is reflected in this decline.

Table 4-25 – Total Overtime Analysis (Cost and Hours)

Overtime Analysis - Cost and Hours							
	2009 Actual	**2010 Actual**	**2011 Actual**	**2012 Budget**	**2013 Budget**	**Change 2009 Actual - 2013**	
	CGAAP *(Note 1)*						
Planned Overtime	$ 686,844	$ 595,708	$ 705,675	$ 488,500	$ 481,800	$ (205,044)	*-29.9%*
Emergency Overtime	474,752	567,372	654,997	617,000	633,000	158,248	*33.3%*
TOTAL Overtime	$ 1,161,596	$ 1,163,080	$ 1,360,672	$ 1,105,500	$ 1,114,800	$ (46,796)	*-4.0%*
Planned Overtime (Hours)	11,270.3	9,282.5	10,376.3	6,921.5	6,627.7	(4,642.5)	*-41.2%*
Emergency Overtime (Hours)	6,958.5	8,148.5	9,262.2	8,742.2	8,707.7	1,749.2	*25.1%*
	18,228.8	17,431.0	19,638.5	15,663.7	15,335.4	(2,893.3)	*-16.1%*
Average $/Hr	$ 63.72	$ 66.72	$ 69.29	$ 70.58	$ 72.69	$ 8.97	*14.1%*
Note 1 - There is no difference between CGAAP and MIFRS							

In 2008, London Hydro implemented a permanent shift truck to respond to service calls after regular hours in order to reduce the cost of overtime. Additionally, the seasonal workload for plant locates is now being outsourced with the intention to lower both emergency and planned overtime. Some increase in purchased services for the locate function which partially offsets these savings are shown in Table 4-27, Page 59.

Total overtime is allocated to operating, capital, and billable services. Table 4-26 on Page 55 provides details on allocation. The overtime in OM&A is $667,527 for the proposed 2013 Test Year. This is a decrease of $33,404 or 4.8% over the 2009 Actuals.

Table 4-26 – Overtime Allocation to OM&A

Overtime - Allocation to OM&A, Capital and Billable	2009 Actual	2010 Actual	2011 Actual	2012 BRIDGE	2013 TEST
Total Overtime	$ 1,161,596	$ 1,163,080	$ 1,360,672	$ 1,105,500	$ 1,114,800
Allocated to Capital and Billable	460,665	497,309	709,161	456,755	447,273
Overtime in OM&A ($)	$ 700,931	$ 665,771	$ 651,511	$ 648,745	$ 667,527
Overtime in OM&A (%)	60.3%	57.2%	47.9%	58.7%	59.9%
Average Hrly Cost	$ 63.72	$ 66.72	$ 69.29	$ 70.58	$ 72.69
Hours of Overtime in OM&A	11,000	9,978	9,403	9,192	9,183
Year over Year Change in Hours		(1,021.8)	(574.6)	(211.2)	(9.4)

Shift and standby pays have increased $13,609 or 21.6% over the 2009 Actual results. Standby pays and shift premiums are negotiated separate from wages, and are impacted by union settlements as well as any increase in the full time workforce. Shift and standby pays are not allocated to capital or billable activities.

Labour Deployment:

The preceding discussion fully outlines the total increase in gross labour and benefit cost. As part of the total labour plan, each department is responsible for the development of deployment plans for capital, operating, billable, and other activities.

The proposed 2013 Test Year includes plans to allocate $10,303,300 of total salaries, wages, and benefits to capital, billable and other activities. This allocation has increased $3,556,670 or 52.7% from the 2009 Actuals to the proposed 2013 Test Year.

Labour is charged, on an hourly basis, to the appropriate work activity based on the type of work being completed. An hourly benefit overhead rate is established to allocate the cost of benefits. Deployment is impacted by the type and level of capital spending, and the mix of internal labour versus outsourced labour used.

Higher levels of internal labour are being allocated to capital activities, therefore reducing the need to purchase and manage external contractors.

Besides the allocation of labour and benefit costs to capital and billable activities, resources are deployed to other activities such as CDM programs. All labour costs incurred for these programs are recovered from the Ontario Power Authority ("OPA"). This is a main factor for the increase in labour cost offset with an increase in deployment for recovery. The resources required for the new and growing OPA programs form part of the total allocation above. The FTE statistics in Table 4-2 Page 6 include new positions related to this program however, due to the deployment to OPA programs, the related incremental cost is not included in OM&A expense.

Labour in OM&A:

As previously discussed, labour cost related to the OM&A programs is $23,084,300 for the proposed 2013 Test Year, an increase of approximately $4,148,162 or 21.9% over the 2009 Actuals. Negotiated wage increases, significant increases in benefit cost, and other cost drivers such as technology, complexity, succession planning, among others previously discussed are increasing OM&A costs over base inflationary increases. The average annual increase over the four years (2009 - 2013) is approximately 5.5%.

Labour and benefit costs are the most significant cost component of OM&A and in the proposed 2013 Test Year this represents 69.1% of total OM&A expense.

Headcount in OM&A has increased from 199.2 FTE to 215.9 FTE. The identification of both new and redundant positions impacting OM&A has been provided in the discussion related to *Base Labour, Benefits, Premium Pays,* and *Deployment*, starting on Page 36 of this Exhibit.

Apprentice Tax Credits:

As part of succession planning, London Hydro has apprentices in various stages of the four year program and new additional positions are forecasted for 2013. These employees qualify for both provincial and federal apprentice tax credit programs. London Hydro has in the past and will continue to submit appropriate claims to take full advantage of these programs. Since 2009, London Hydro has received approximately $126,800 in funding through these programs.

These tax credits for the 2012 Bridge and the proposed 2013 Test Year are $62,300 and $30,700 respectively. These tax credits are included in the calculation of PILs and therefore excluded from the total labour in OM&A to avoid duplication. In the past, London Hydro netted these credits in OM&A as well as including them as a tax credit in the calculation of PILs in error.

Purchased Services:

The major cost category of Purchased Services, includes costs such as external contactors, plant locate services, legal services, bill printing and mailing services, collection and meter reading services, among others. This is the second largest cost element in OM&A and represents approximately 14.3% of the total OM&A cost.

The proposed 2013 Test Year for purchased services has increased $942,109 or 23.1% from the 2009 Actuals. This is an overall average increase of 5.8% annually.

Table 4-27 on Page 59 provides a breakdown of the significant cost variances by type of purchased service.

The business environment has changed significantly over the period since the last rebasing year (2009). During this time new technology has replaced the traditional method of reading meters and that fact is reflected in the overall decrease in contracted meter reading service of $297,024 or 29.8%.

At the same time new information and billing systems required to support TOU billing were put into service. This results in higher external contractor and consulting services to support and maintain the system. The system and billing is complex and the regulatory requirements are constantly changing. Contractor and consultant costs have increased $450,788 or 55.8% over the 2009 Actuals. As previously discussed in the *Base Labour* discussion starting on Page 39, London Hydro has been modifying the mix of resources required to maintain the various information systems and moving to reduce external resources and replace with internal labour. This will provide consistency, improve in-house knowledge, allow for more timely response to issues, and reduce cost.

The historical actual cost for contractor and consulting services peaked in 2011 at $1,750,746. The proposed 2013 Test Year is $1,258,100 a decline of $492,646 or 28.1% since that time.

Plant Locate Services have increased $203,863 or 79.6% over the 2009 Actuals. This is primarily due to increased volumes handled by the service provider as evidenced in actual cost increases in 2010 and 2011. The loss of one internal staff member in this area also shifted more work to the external contractor. The Locates contractor in the London area is able to provide locating services for multiple utilities at the same time so this is one area where the continued use of external resources improves efficiencies.

Wholesale Metering Service expense was a new cost commencing in 2006. Since then, and in accordance with Chapter 6 of the Market Rules, London Hydro took full responsibility for wholesale metering points over a number of years based on the scheduled meter re-verification dates. Additional costs related to this transition such as non-recurring exit fees were incurred in 2009 and 2011 and explain the expense fluctuations in those years. The new on-going cost to maintain the wholesale metering points and the telephone lines for data interrogation is reflected in the 2012 Bridge and the proposed 2013 Test Year.

London Hydro has discontinued the Epost program and has expanded its website to offer on-line access to bills and usage information to better service customers.

Contracted collection service cost has fluctuated over the time period under review; however, the 2012 Bridge Year is forecasted to be approximately 2% higher than the 2010 and 2011 actual costs. The proposed 2013 Test Year is expected to remain at the 2012 level. Field collection activity continues to increase. Statistics and year over year comparisons for contracted collection services are provided in the section related to *Bad Debt*, starting on Page 60 of this Exhibit. In 2011 as a result of an RFP process, a new contract with lower collection fees related primarily to disconnection and reconnections was negotiated.

Table 4-27 – Purchased Services

SUMMARY OF PURCHASED SERVICES - SIGNIFICANT COST VARIANCES									
	CGAAP							MIFRS	
	2009 OEB Submission	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST
			$	$	$	$	$	$	$
Significant Expense & Cost Variances:									
Operations and Maintenance:									
Contractor Services	401,500	401,500	418,683	447,890	421,945	415,000	484,700	415,000	484,700
Plant Locate Services	292,200	292,200	256,137	388,154	416,594	440,000	460,000	440,000	460,000
PCB Elimination Services	5,200	5,200	22,684	-	5,328	5,000	5,000	5,000	5,000
Wholesale Metering Services	123,900	123,900	140,772	116,056	136,208	110,600	113,900	110,600	113,900
General and Administrative:									
Advertising Expense	158,400	158,400	155,747	162,562	115,828	203,700	217,400	203,700	217,400
Legal Fees	147,100	147,100	90,853	89,643	105,349	170,600	170,600	170,600	170,600
Collection Agency Fees	90,000	90,000	54,529	65,960	74,900	77,500	80,000	77,500	80,000
Disaster Recovery Expense	51,500	51,500	58,884	52,640	50,828	53,500	54,000	53,500	54,000
Contractor / Consulting Services	796,700	796,700	807,312	1,689,228	1,750,746	1,300,400	1,258,100	1,300,400	1,258,100
Bill Printing Services	59,700	59,700	71,360	94,283	88,231	100,000	100,000	100,000	100,000
Epost Contracted Services	38,600	38,600	43,149	46,124	32,033	-	-	-	-
Payment Processor Fees	92,700	92,700	109,095	105,150	98,968	65,200	63,200	65,200	63,200
Contract Collection Services	250,000	250,000	159,243	244,564	244,790	250,000	250,000	250,000	250,000
Contract Meter Reading Service	1,060,900	1,060,900	997,024	933,196	747,569	800,000	700,000	800,000	700,000
						-		-	
	3,568,400	3,568,400	3,385,472	4,435,450	4,289,317	3,991,500	3,956,900	3,991,500	3,956,900
Other Expense & Cost Variances:									
Operations and Maintenance:	82,600	82,600	68,801	94,320	55,123	95,300	100,000	95,300	100,000
General and Administrative:	691,000	691,000	618,118	612,900	670,548	710,100	718,700	710,100	718,700
Smart Meter Costs *(Note 1)*						377,100	238,900	377,100	238,900
	773,600	773,600	686,919	707,220	725,671	1,182,500	1,057,600	1,182,500	1,057,600
TOTAL EXPENSE & COST VARIANCE:	**4,342,000**	**4,342,000**	**4,072,391**	**5,142,670**	**5,014,988**	**5,174,000**	**5,014,500**	**5,174,000**	**5,014,500**
Note 1 - see detailed schedule of smart meter expense - Table 4-5									

Materials & Supplies:

Material and Supplies are forecasted to be $1,134,000 in the 2012 Bridge Year and $1,176,000 in the proposed 2013 Test Year. This is an increase of $42,000 or 3.7%. The increase from the 2009 Actual to the proposed 2013 Test Year is $173,992 or 17.4%. This is an overall average annual increase of 4.4%.

Factors such as general price increases, equipment failure rates due to storms, lightning, and system damage, and other uncontrollable events have all contributed to increases in the total cost of conductors, and hardware and attachments.

London Hydro conducts periodic audits on its distribution system and variances in materials and supplies year over year are directly related to findings.

London Hydro began to utilize new fire retardant oil to retro-fill network transformers in 2012. Although this new enhanced product is more expensive, it does significantly improve safety for employees and the public, which is one of London Hydro's main corporate goals. The total incremental cost of using this product is approximately $26,000 annually.

There is no impact related to this cost category for MIFRS and no significant incremental impact due to the implementation of smart meters.

Table 4-28 – Materials and Supplies

SUMMARY OF MATERIALS & SUPPLIES - SIGNIFICANT COST VARIANCES											
	CGAAP							MIFRS		CGAAP VARIANCE	
	2009 OEB Submission	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST	2009 ACTUAL to 2013 TEST	
			$	$	$	$	$	$	$	$	%
Significant Expense & Cost Variances:											
Operations and Maintenance:											
Conductors	30,600	30,600	34,326	53,241	45,658	50,300	51,800	50,300	51,800	17,474	50.9
Hardware, Attachs & Terms	360,500	360,500	330,385	355,430	384,085	414,500	422,900	414,500	422,900	92,515	28.0
General Maintenance Supplies	102,100	102,100	113,615	122,535	85,045	121,686	142,863	121,686	142,863	29,248	25.7
Small Tool & Shop Supplies	218,600	218,600	180,931	189,538	167,895	213,600	219,100	213,600	219,100	38,169	21.1
Poles	25,800	25,800	36,403	44,146	22,278	40,000	40,000	40,000	40,000	3,597	9.9
General and Administrative:											
Office Supplies	84,800	84,800	93,171	90,344	86,438	100,200	100,800	100,200	100,800	7,629	8.2
Forms, Prints & Stationery	131,700	131,700	127,111	76,015	115,038	87,700	92,400	87,700	92,400	(34,711)	-27.3
	954,100	954,100	915,941	931,249	906,438	1,027,986	1,069,863	1,027,986	1,069,863	153,922	16.8
Other Expense & Cost Variances:	120,400	120,400	86,067	88,202	98,956	106,000	106,100	106,000	106,100	20,033	23.3
TOTAL EXPENSE & COST VARIANCE:	1,074,500	1,074,500	1,002,008	1,019,451	1,005,394	1,133,986	1,175,963	1,133,986	1,175,963	173,955	17.4

Bad Debt:

Bad Debt expenses are forecasted to be $1,000,000 in both the 2012 Bridge and the proposed 2013 Test Year. This is $465,000 higher than the 2009 Board Approved level or an 86.9% increase.

The cost of service application for the last rebasing year of 2009 provided for an estimated bad debt of $535,000. Actual results were significantly higher, with bad debt in 2009 of $825,000. This was followed with $1,120,000 in 2010 and $800,000 in 2011. During this time customers were adversely affected by the economy although some improvement in bad debt expense was experienced in 2011. Over the first three years following the rebasing, London Hydro has under recovered $1,140,000 in bad debt expense. London Hydro continues to actively pursue recovery of these unpaid accounts with the use of external collection agency assistance.

London Hydro has improved systems and processes in order to minimize bad debt loss. Many factors in play are beyond London Hydro's control and all efforts are being made to minimize increases in bad debt.

Recent regulatory directions that impacts London Hydro's collection practice and bad debt include, among others:

- new customer option to carry forward balances into the new budget billing cycle year
- new directive to apply deposits to outstanding arrears prior to field collections
- new extended arrears re-payment options, with longer time extensions for low income customers
- new wait time (10 days) required between initial collection notice and actual disconnection action

Although the economy has slowly recovered, the collection action required year to date in 2012 indicates that bad debt will continue to be a significant issue. The impact of general price increases, TOU billing, as well as regulatory directives impacting London Hydro's collection practices and the level of security deposits allowed to be held, are all influencing the forecasted bad debt.

Statistics show continued high levels of field activity including the number of accounts "qualifying" for collection action, field collection notices (dropped cards), and disconnection action during the first six months of 2012. Past due receivables, requiring collection action during this period totaled 26,257 accounts or 10.2% higher than the same time period in 2011. Field collection calls made were 27,162 and are up 20.5% year over year, and actual disconnects have increased by 9.7% year over year.

Not all accounts requiring collection action result in bad debt, however these statistics are indicators that the collection action required to minimize bad debt expense remains high.

The total active customers increased over the four year period (2009 to 2013) by 4.4%.

Although London Hydro provides a full cycle water billing and collection service to the Corporation of the City of London, it is important to note that there is no bad debt impact due to the provision of this service to the City. All water accounts that are un-collectible are funded 100% by the City of London and are currently outside of the existing service level agreement between London Hydro and the City. For further information related to this agreement, refer to the section entitled: *"Shared Services & Corporate Cost Allocation"* which begins on Page 98.

Property Tax and Insurance:

Property tax and insurance is forecasted to be $1,135,700 in the 2012 Bridge Year and $1,148,500 in the proposed 2013 Test Year. This is an increase of $12,800 or 1.1%. The increase from the 2009 Actual to the proposed 2013 Test Year is $12,459 or 1.1%.

Insurance is forecasted to be $485,700 in the 2012 Bridge Year and $498,500 in the proposed 2013 Test Year. This is an increase of $12,800 or 2.6%. The increase from the 2009 Actual to the proposed 2013 Test Year is $54,747 or 12.3%.

There are two primary reasons causing the increase in insurance expense. Firstly, property insurance experienced a significant increase from 2010 forward due to an insurance review in 2009 that indicated that London Hydro should improve coverage for transformer stations. This fact, combined with the recent addition of the smart meters, contributed to the increase in premiums. Secondly, there was an increase in excess liability premiums due to a change in coverage. London Hydro increased its liability coverage from $23 million with an excess of $10 million to $23 million with an excess of $20 million. Coverage was increased as a precautionary measure subsequent to the insurance review. It was determined, in light of recent known lawsuits for major liabilities in excess of $35 million, that London Hydro, and indirectly its stakeholders and customers, were exposed in the event of a major liability.

Property tax is forecasted to be $650,000 in both the 2012 Bridge Year and 2013 Test Year. The decrease from the 2009 Actual to the proposed 2013 Test Year is $42,288 or 6.1%. This is primarily due to the decrease in property tax rates, from 4.87% in 2009 to 4.13% in 2011. It is expected that there will be no change in rates for 2012 and 2013.

Facilities Maintenance and Repair:

Facilities Maintenance and Repair expense is forecasted to be $1,710,500 in the 2012 Bridge Year and $1,738,000 in the proposed 2013 Test Year. This is an increase of $27,500 or 1.6%. The increase from the 2009 Actual to the proposed 2013 Test Year is $269,613 or 18.4%. This is an overall average annual increase of 4.6%.

Table 4-29, below provides details of the elements of cost related to this major cost category.

Table 4-29 - Facilities Maintenance & Repair

SUMMARY OF FACILITIES MAINTENANCE & REPAIR - SIGNIFICANT COST VARIANCES											
	CGAAP							MIFRS		CGAAP VARIANCE	
	2009 OEB Submission	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST	2009 ACTUAL to 2013 TEST	
	$	$	$	$	$	$	$	$	$	$	%
Significant Expense & Cost Variances:											
Contractor Services	218,000	218,000	210,912	169,266	220,546	265,000	267,000	265,000	267,000	56,088	26.6
HVAC Expense	100,000	100,000	156,437	232,602	237,886	160,000	165,000	160,000	165,000	8,563	5.5
Utilities	386,300	386,300	361,249	367,270	360,980	380,000	390,000	380,000	390,000	28,751	8.0
Electrical	80,000	80,000	120,305	168,924	120,327	120,000	120,000	120,000	120,000	(305)	-0.3
Painting	40,000	40,000	40,311	35,913	25,590	40,000	40,000	40,000	40,000	(311)	-0.8
Janitorial Services	246,500	246,500	221,145	201,801	199,634	218,500	223,500	218,500	223,500	2,355	1.1
Landscape Expense	75,000	75,000	55,847	32,264	52,350	55,000	55,000	55,000	55,000	(847)	-1.5
Snow Removal	90,000	90,000	56,834	124,169	94,768	90,000	90,000	90,000	90,000	33,166	58.4
Plumbing/Sewer	60,000	60,000	30,817	63,178	32,570	50,000	50,000	50,000	50,000	19,183	62.2
Furniture Mntce & Expense	30,000	30,000	57,467	79,370	61,898	72,000	73,500	72,000	73,500	16,033	27.9
Door Maintenance	20,000	20,000	12,585	26,843	25,192	25,000	25,000	25,000	25,000	12,415	98.7
Fencing & Gates	25,000	25,000	5,644	11,319	2,026	15,000	15,000	15,000	15,000	9,356	165.8
Fire Protection	30,000	30,000	22,601	27,521	38,060	42,000	43,000	42,000	43,000	20,399	90.3
Paving	15,000	15,000	15,062	27,355	24,350	25,000	25,000	25,000	25,000	9,939	66.0
Standby Generator Maintenance	22,000	22,000	29,084	40,356	48,809	46,500	48,000	46,500	48,000	18,916	65.0
	1,437,800	1,437,800	1,396,299	1,608,150	1,544,987	1,604,000	1,630,000	1,604,000	1,630,000	233,701	16.7
Other Expense & Cost Variances:	94,000	94,000	72,088	73,669	71,121	106,500	108,000	106,500	108,000	35,912	49.8
TOTAL EXPENSE & COST VARIANCE:	**1,531,800**	**1,531,800**	**1,468,387**	**1,681,819**	**1,616,108**	**1,710,500**	**1,738,000**	**1,710,500**	**1,738,000**	**269,613**	**18.4**

Office Equipment Services and Maintenance:

Office Equipment Services and Maintenance expense is forecasted to be $1,972,500 in the 2012 Bridge Year and $1,919,200 in the proposed 2013 Test Year. This is a decrease of $53,300 or 2.7% year over year. The increase from the 2009 Actual to the proposed 2013 Test Year is $576,669 or 43.0%. This is an overall average annual increase of 10.8%.

Table 4-30, on Page 64 provides details of the elements of cost related to this major cost category.

London Hydro negotiated new service contracts for both photocopier and telephone and changed service providers in 2011 which resulted in cost declines of $18,251 and $26,626 respectively over the 2009 Actuals.

Excluding the impacts of smart meters, software and hardware expense has increased over the 2009 Actuals by $363,261 and $117,032 respectively. Cost increases are primarily related to:

- new billing system implemented mid-year in 2009
- software licenses & associated maintenance agreements to deliver new functionality to meet customer demand, including new systems such as GIS and OMS
- hardware costs including servers, storage, and associated maintenance agreements to store, process and secure increasing volumes of data
- other technology changes

Table 4-30 - Office Equipment Services and Maintenance

SUMMARY OF OFFICE EQUIPMENT SERVICES & MAINTENANCE - SIGNIFICANT COST VARIANCES

	CGAAP							MIFRS		CGAAP VARIANCE	
	2009 OEB Submission	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST	2009 ACTUAL to 2013 TEST	
	$	$	$	$	$	$	$	$	$	$	%
Significant Expense & Cost Variances:											
Photocopier Equipment Lease	116,400	116,400	125,451	122,542	103,529	105,500	107,200	105,500	107,200	(18,251)	-14.5
Telephone Equipment / Lines	198,100	198,100	268,726	260,584	221,537	241,900	242,100	241,900	242,100	(26,626)	-9.9
Software Expense	770,600	770,600	680,439	756,180	1,023,665	1,100,900	1,043,700	1,100,900	1,043,700	363,261	53.4
Hardware Maintenance Expense	93,900	93,900	117,968	110,780	232,228	228,900	235,000	228,900	235,000	117,032	99.2
	1,179,000	1,179,000	1,192,584	1,250,086	1,580,959	1,677,200	1,628,000	1,677,200	1,628,000	435,416	36.5
Other Expense & Cost Variances:	145,000	145,000	149,946	177,713	167,673	164,500	164,600	164,500	164,600	14,654	9.8
Smart Meter Expenses *(Note 1)*						130,800	126,600	130,800	126,600	126,600	100.0
TOTAL EXPENSE & COST VARIANCE:	**1,324,000**	**1,324,000**	**1,342,531**	**1,427,800**	**1,748,632**	**1,972,500**	**1,919,200**	**1,972,500**	**1,919,200**	**576,669**	**43.0**

Note 1 - see detailed schedule of smart meter expense - Table 4-5

Table 4-31, on Page 65 provides a further breakdown of the software and hardware expense.

Table 4-31 – Software and Hardware Expense

SUMMARY OF SOFTWARE AND HARDWARE EXPENSE							
	CGAAP					MIFRS	
	2009 ACTUAL $	2010 ACTUAL $	2011 ACTUAL $	2012 BRIDGE $	2013 TEST $	2012 BRIDGE $	2013 TEST $
Software							
Applications	529,842	862,985	883,507	972,100	910,000	972,100	910,000
Infrastructure	59,476	43,684	52,735	37,900	39,000	37,900	39,000
Network Security	31,778	11,905	19,669	27,400	29,300	27,400	29,300
Network & Telecom	55,316	52,986	65,835	62,700	64,600	62,700	64,600
End User Computing	4,028	4,977	1,921	800	800	800	800
TOTAL SOFTWARE	**680,439**	**976,537**	**1,023,667**	**1,100,900**	**1,043,700**	**1,100,900**	**1,043,700**
Hardware							
Servers & Storage	51,162	63,699	182,639	175,500	179,900	175,500	179,900
Network Security	9,234	10,394	4,141	13,400	13,800	13,400	13,800
Network & Telecom	32,700	27,541	22,317	24,000	24,800	24,000	24,800
End User Computing	24,181	9,147	23,129	10,200	10,500	10,200	10,500
Peripherals	692	-	-	5,800	6,000	5,800	6,000
TOTAL HARDWARE	**117,968**	**110,781**	**232,226**	**228,900**	**235,000**	**228,900**	**235,000**
Smart Meter Costs							
Software	-	-	-	119,500	120,600	119,500	120,600
Hardware	-	-	-	6,000	6,000	6,000	6,000
TOTAL SMART METER COSTS	**-**	**-**	**-**	**125,500**	**126,600**	**125,500**	**126,600**
TOTAL	**798,408**	**1,087,318**	**1,255,893**	**1,455,300**	**1,405,300**	**1,455,300**	**1,405,300**

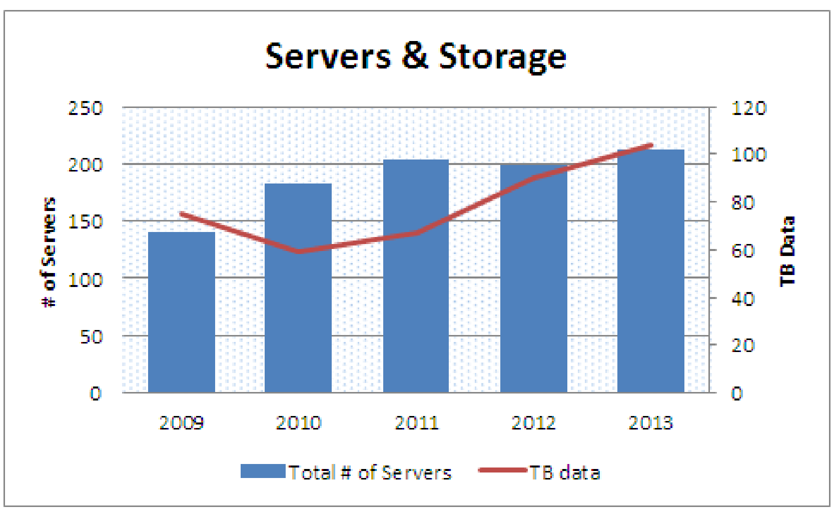
The detailed costs related to smart meter expenses are provided in Table 4-5, on Page 11; however, to summarize includes wireless area network ("WAN") maintenance and licensing fees, meter data unification synchronization ("MDUS") and Operational Data Store ("ODS") maintenance fees, and advanced metering infrastructure ("AMI") annual maintenance fees, among others.

The complexity of the information systems require dedicated landscapes to support activities associated with installing, configuring, integrating, updating and modifying applications. Separate landscapes to ensure proper testing across the meter-to-cash business process are essential to ensuring the quality of the final product released to production. This drives up the number of servers and copies of the data required and the total demand on storage.

As an example of the growing complexity, prior to 2009, one read per month was required from each customer which resulted in approximately 150,000 monthly meter readings. In 2012, there is now a requirement to present customers with a view of yesterday's hourly readings. This equates to approximately 108,000,000 meter readings per month. There is a need to ensure that all of these readings are validated and estimated where necessary to ensure that any gaps that may have resulted from outages, disconnects, reconnects, moves, and other planned events are accurately reflected to its customers. These requirements all impact on the need for additional storage, processing horsepower and associated back up and batch processing.

The following chart illustrates the growth in Terabytes of data and the associated servers (a combination of physical and virtual). The initial decrease was the result of a data consolidation initiative.

Chart 4-3 – Servers and Storage Requirements



Processing cycle times are now measured in hours not weeks. The volume of meter data has increased from one data point per meter to 720 over the course of a month. These new regulated service level requirements are driving the need to provide 24/7 support for SAP/AMI, including smart metering infrastructure, Operational Data Store, TOU Billing, web presentment and MDM/R interfacing to support meter to cash business processes and maintain high customer satisfaction.

By adding functionality and improving the currency of information available has required a more complex hardware and software infrastructure with increasing interdependencies between applications. Timeliness and accuracy of data is, and will continue to be of paramount importance in terms of engaging and retaining customers trust in their information. As an indication of the growing complexity and London Hydro's Quality Assurance commitment, test cases performed have grown from 1,685 in 2009 to 6,949 in 2012.

Postage:

Postage expense is forecasted to be $1,035,000 in the 2012 Bridge Year and $1,070,000 in the proposed 2013 Test Year. This is an increase of $35,000 or 3.4%. The increase from the 2009 Actual to the proposed 2013 Test Year is $195,549 or 22.4%. This is an overall average annual increase of 5.6%.

Both volumes and price have impacted the cost of postage. Postage rates are increasing 17.5% from the 2009 Actual to the proposed 2013 Test year. Table 4-32, below, provides historical actual unit prices. Pre-Sorted mail is approximately 80% of the total mail. Price increases are calculated based on a blended rate for pre-sort and 1st Class mail.

Table 4-32 - Postage Rates – Historical Unit Cost

Postage Rates - Historical Cost									
YEAR	Pre-Sort - 80%				Ist Class - 20%				Blended
	Unit Price	**Change**	**%**	**% cumulative**	**Unit Price**	**Change**	**%**	**% cumulative**	
2009	0.51	-	-	0	0.54	-	-	-	
2010	0.54	0.03	5.88%	5.88%	0.57	0.03	5.56%	5.56%	
2011	0.56	0.02	3.70%	9.80%	0.59	0.02	3.51%	9.26%	
2012	0.58	0.02	3.57%	**13.73%**	0.61	0.02	3.39%	**12.96%**	**13.6%**
2013	0.60	0.02	3.45%	**17.65%**	0.63	0.02	3.28%	**16.67%**	**17.45%**
		$0.09				$0.09			

Fleet Operations and Maintenance:

As previously discussed, the total Fleet Operation and Maintenance expense is forecasted to be lower under MIFRS due to the new service lives adopted for rate making purposes. The impact of MIFRS is to lower vehicle and equipment depreciation by $357,000 and $471,000 over the CGAAP levels for the 2012 Bridge and the 2013 Test Years, respectively. All other expense remains the same under both CGAAP and MIFRS standards.

Fleet expense is allocated to operating, capital, and billable activities. Table 4-33, on Page 69 provides the elements of cost and the significant cost variances related to maintaining London Hydro's fleet. Table 4-39 on Page 77 details the allocation of the cost of the fleet and material handling to operating, capital, and billable activities.

Under MIFRS, the Fleet Operations and Maintenance expense is forecasted to be $1,492,000 in the 2012 Bridge Year and $1,685,000 in the proposed 2013 Test Year. This is an increase of $193,000 or 12.9% year over year.

Since 2009, London Hydro has made significant capital investments in fleet and equipment and has changed its practice of leasing vehicles. This has resulted in higher depreciation expense, lower lease cost, and lower vehicle parts and auto body repair expense.

Fuel prices, although difficult to predict, are expected to continue to increase in 2012 and 2013. The average unit price is forecasted to increase 2.5% and 3.0% in 2012 and 2013, respectively. Table 4-34, on Page 69 provides the historical and forecasted average unit price of fuel. This average is a blended rate for unleaded, coloured diesel, and diesel. Fuel cost has increased 18.0% between 2009 and 2011. Overall the increase in fuel price is expected to be 25.3%.

Table 4-33 - Fleet Operations and Maintenance

SUMMARY OF FLEET OPERATIONS & MAINTENANCE - SIGNIFICANT COST VARIANCES											
	CGAAP							MIFRS		CGAAP VARIANCES	
	2009 OEB Submission	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST	2009 ACTUAL to 2013 TEST	
	$	$	$	$	$	$	$	$	$	$	%
Significant Expense & Cost Variances:											
Lease Expense	72,000	72,000	62,184	20,466	13,778	10,000	10,000	10,000	10,000	(52,184)	-83.9
Fuel Expense	388,200	388,200	254,433	267,505	321,846	330,000	340,000	330,000	340,000	85,567	33.6
Vehicle Parts / Auto Body Repair	472,100	472,100	477,936	329,633	394,899	415,000	435,000	415,000	435,000	(42,936)	-9.0
V&E Depreciation	481,900	481,900	458,274	553,431	777,730	926,000	1,128,000	569,000	727,000	669,726	146.1
	1,414,200	1,414,200	1,252,826	1,171,035	1,508,252	1,681,000	1,913,000	1,324,000	1,512,000	660,174	52.7
Other Expense & Cost Variances:	147,500	147,500	161,790	162,100	151,372	168,000	173,000	168,000	173,000	11,210	6.9
TOTAL EXPENSE & COST VARIANCE:	**1,561,700**	**1,561,700**	**1,414,617**	**1,333,134**	**1,659,625**	**1,849,000**	**2,086,000**	**1,492,000**	**1,685,000**	**671,383**	**47.5**

Table 4-34 - Average Fuel Cost (2009 Actual to 2013 Forecast)

	Average Fuel Cost per Litre - Historical and Forecasted				
	2009	2010	2011	BRIDGE 2012	TEST 2013
Average Fuel cost *(Note 1)*	$ 0.772	$ 0.809	$ 0.916	$ 0.939	$ 0.968
Year on Year Change ($)		$ 0.037	$ 0.107	$ 0.023	$ 0.028
Year on Year Change (%)		**4.7%**	**13.3%**	**2.5%**	**3.0%**
Overall Change ($)					$ 0.195
Overall Change (%)					**25.3%**

(Note 1) - blend of unleaded, coloured diesel, and diesel fuel grades

Corporate Training and Employee Expenses:

Corporate Training and Employee expense is forecasted to be $1,064,500 in the 2012 Bridge Year and $1,029,800 in the proposed 2013 Test Year. This is a decrease of $34,700 or 3.3%. The increase from the 2009 Actual to the proposed 2013 Test Year is $264,757 or 34.8%. This is an overall average annual increase of 8.7%.

A breakdown of significant cost variance by expenditure is provided in Table 4-35, on Page 71.

Corporate training is the main reason for the overall increase in this major cost category. Employee training to develop and sustain skills during periods of significant change is required. Training programs are related to the following, among others:

- Health and Safety
- Regulatory Compliance
- Supervisory – Management professional development
- New information systems (technology)
- Apprentice training, and other skill trade training

Generally the industry is experiencing a high demand and short supply of skilled resources which results in the need for London Hydro to expand in-house training and develop programs. Employee demographics continue to indicate that a significant percentage of London Hydro's workforce will be eligible to retire over the coming years. It is imperative that employees develop their knowledge and skills in order to meet the current and future expectations of London Hydro's customers. This is part of London Hydro's Strategic Plan (Exhibit 1, Appendix 1A) and is impacted by technology and other corporate objectives. Also, a recent report issued by the Electricity Sector Council, and sponsored by the Government of Canada entitled: "Knowledge Management & Transfer for the Electricity Industry in Canada" provides further insight related to training requirements now and into the future. A link to this report is provided on Page 37 of this Exhibit and excerpts of the report are contained in Appendix 4A.

Other employee expenses such as overtime meals and boot and tool allowances are impacted by union negotiations as well and increases in the labour complement.

London Hydro offers a wellness program to employees, and belongs to the London Employees Assistance Consortium ("LEAC"), which is a not for profit, confidential counseling service. This service provides assistance to employees dealing with stress, change, substance abuse, work related issues and personal and family problem resolution. The costs for the proposed 2013 Test Year are forecasted to increase by $26,881 or 86.7% over the 2009 Actuals.

Other employee expenses include the cost of trade licenses, fitness centre expense, and personal auto mileage.

Table 4-35 - Corporate Training and Employee Expenses

SUMMARY OF CORPORATE TRAINING AND EMPLOYEE EXPENSES - SIGNIFICANT COST VARIANCES											
	CGAAP							MIFRS		CGAAP VARIANCE	
	2009 OEB Submission	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST	2009 ACTUAL to 2013 TEST	
	$	$	$	$	$	$	$	$	$	$	%
Significant Expense & Cost Variances:											
O/T Meal Allowance	32,100	32,100	26,840	31,943	32,567	35,000	34,700	35,000	34,700	7,860	29.3
Corporate Clothing	70,600	70,600	72,023	47,960	77,449	71,800	71,600	71,800	71,600	(423)	-0.6
Boot and Tool Allowance	42,100	42,100	39,100	35,280	37,666	45,700	45,600	45,700	45,600	6,500	16.6
Membership Dues	20,900	20,900	16,894	20,943	21,519	26,700	26,200	26,700	26,200	9,306	55.1
Department Safety Supplies	99,500	99,500	107,743	94,145	119,346	104,100	105,300	104,100	105,300	(2,443)	-2.3
Relocation / Recruitment Exp	30,600	30,600	20,457	34,159	19,478	30,000	30,000	30,000	30,000	9,543	46.7
Corporate Medical Expenses	16,000	16,000	11,338	8,202	15,466	24,400	24,700	24,400	24,700	13,362	117.9
LEAC / Employee Wellness	25,500	25,500	31,019	43,096	51,032	56,900	57,900	56,900	57,900	26,881	86.7
Recognition Gifts	33,700	33,700	20,454	23,242	30,830	27,000	26,500	27,000	26,500	6,046	29.6
Employee Development / Training	510,100	385,100	368,735	341,891	558,549	562,400	527,000	562,400	527,000	158,265	42.9
	881,100	756,100	714,601	680,861	963,902	984,000	949,500	984,000	949,500	234,899	32.9
Other Expenses & Cost Variances:	51,800	51,800	46,442	54,023	66,783	76,500	76,300	76,500	76,300	29,858	64.3
Smart Meter Expenses *(Note 1)*						4,000	4,000	4,000	4,000	4,000	-
TOTAL EXPENSE & COST VARIANCE:	**932,900**	**807,900**	**761,043**	**734,884**	**1,030,685**	**1,064,500**	**1,029,800**	**1,064,500**	**1,029,800**	**264,757**	**34.8**

Note 1 - see detailed schedule of smart meter expense - Table 5

Rental, Regulatory and Other Expenses:

Rental, Regulatory and Other expense is forecasted to be $1,203,200 in the proposed 2013 Test Year. This is an increase of $89,871 or 8.1% over the 2009 Actuals.

A breakdown of significant cost variance by expenditure is provided in Table 4-36, on Page 73.

Incremental Smart Meter costs of $72,800 and $73,400 for the 2012 Bridge and proposed 2013 Test Years respectively are one factor causing the overall increase in this major cost category. See Table 4-5 on Page 11 for the details related to this Smart Meter cost.

The 2012 Bridge Year costs for Smart Meters are presented in various cost categories, such as purchased services, and office equipment services and maintenance, among others, on a gross basis; however, the total incremental cost of smart meters is budgeted for recovery through the SMIRR. The transition to smart meters results in lower costs related to the traditional meter reading function. The estimated cost savings has been included in this major cost category. This allows for better cost comparability between the 2012 Bridge and proposed 2013 Test

Years for the on-going costs of smart meters, included in OM&A for recovery through distribution rates in 2013 and the future.

Non-recoverable insurance claims expense has been virtually eliminated as part of the insurance review conducted in 2009. Overall cost reductions between 2009 Actual to 2013 Test are $36,052 or 96.0%. For more information related to insurance, refer to the preceding discussion on Page 62.

The total cost incurred and forecasted in connection with the preparation of the rate application, interrogatory responses, and the final Board Decision is captured in this major cost category. Total costs related to Board ordered studies, and forecasts for legal, intervenors, and consulting for load forecast are expected to be $362,182. Details are provided in Table 4-37, Page 73. Table 4-16 on Page 31 is provided as per the filing requirements related to OEB Appendix 2-M.

Recovery of these one-time costs are spread cost over a four year period and, therefore $90,546 has been included in total OM&A. Historical comparisons to the 2009 Actual are impacted by the timing of the cost incurred related to the 2009 cost of service application. Historical actuals are not smoothed, and variances are related to timing.

Table 4-36 - Rental, Regulatory and Other Expenses

SUMMARY OF RENTAL REGULATORY & OTHER EXPENSES - SIGNIFICANT COST VARIANCES	CGAAP							MIFRS	
	2009 OEB Submission $	2009 OEB Approved $	2009 ACTUAL $	2010 ACTUAL $	2011 ACTUAL $	2012 BRIDGE $	2013 TEST $	2012 BRIDGE $	2013 TEST $
Significant Expense & Cost Variances:									
Non-recoverable Claims Exp	40,800	40,800	37,552	2,285	606	1,500	1,500	1,500	1,500
School Safety Program	12,200	12,200	11,407	13,402	13,212	14,000	15,000	14,000	15,000
Corporate Membership Fees	134,800	134,800	138,932	144,202	149,273	150,700	154,200	150,700	154,200
Property Lease	189,000	189,000	190,619	190,656	188,423	189,200	189,200	189,200	189,200
OEB Regulatory Expense	367,200	367,200	384,242	377,039	393,158	405,000	417,200	405,000	417,200
OEB Hearing Expense	72,800	72,800	161,345	-	(30,000)	90,000	90,500	90,000	90,500
IMO Prudential Fees	28,600	28,600	26,335	31,780	26,336	28,000	30,000	28,000	30,000
	845,400	845,400	950,432	759,365	741,008	878,400	897,600	878,400	897,600
Other Expense & Cost Variances:	178,000	160,363	162,898	138,198	344,973	233,300	232,200	233,300	232,200
Total Before Smart Meters	**1,023,400**	**1,005,763**	**1,113,329**	**897,563**	**1,085,981**	**1,111,700**	**1,129,800**	**1,111,700**	**1,129,800**
Incremental Smart Meter Expenses *(Note 1)*						72,800	73,400	72,800	73,400
Incremental Smart Meter Cost Adjustment						(330,000)		(330,000)	
TOTAL EXPENSE & COST VARIANCE:	**1,023,400**	**1,005,763**	**1,113,329**	**897,563**	**1,085,981**	**854,500**	**1,203,200**	**854,500**	**1,203,200**

Note 1 - see detailed schedule of smart meter expense - Table 4-5

Table 4-37 - Cost of Service Application Incremental Costs

Costs Related to Cost of Service Application	MAJOR COST CATEGORY: Rent, Regulatory, and Other	EXPENSED IN: 2011	2012	2013	TOTAL
OEB Rate Application Incremental Cost:					
Load Forecast	15,000	-	15,000		15,000
Legal	125,000	-	87,500	67,500	155,000
Intervenors	130,000	-		100,000	100,000
	270,000	-	102,500	167,500	270,000
OEB Ordered Studies					
Lead/Lag	36,872	21,320	15,552	-	36,872
Cost of Service - City Water Billing	55,310	31,982	23,328	-	55,310
	92,182	53,302	38,880	-	92,182
	362,182	53,302	141,380	167,500	362,182
Amount Included for Rate Making	**90,546**				

Studies and Special Projects:

Studies and Special Projects:

Annually London Hydro conducts special studies which provide information on infrastructure, reliability, technology, customer satisfaction, utility benchmarking, and safety, among others. Although some studies vary from year to year, on-going funding is required to enable London Hydro to pursue new initiatives. Studies provide valuable information on how London Hydro has performed, and assists in developing new ideas on how future improvements can be made.

Special projects establish new efficient ways of sharing information, and are targeted to improve health and safety.

Spending on studies and special projects assists London Hydro in obtaining key corporate goals such as becoming more efficient, providing more reliable service and information, progressing with new technology, and further reducing cost for our customers wherever possible.

Prior year budget levels have been inadequate to fund more in-depth studies. The 2012 Bridge and proposed 2013 Test Years include funding for various studies and special projects in the amount of $105,000. This is an increase of $46,620 or 79.9% over the 2009 Actual spending.

In 2012 and 2013 the following studies and special projects will be undertaken to initiate:

- on-going infrastructure failure studies and testing
- power quality testing and analysis for large industrial customers
- load forecast studies
- engineering support projects in conjunction with the University of Western Ontario and Fanshawe College
- a library of training and safety related videos in conjunction with other LDCs
- an orientation video for new hires, to enhance general knowledge of organization
- a progression to the platinum level of the zero quest program in association with the Infrastructure Health and Safety Association (“IHSA”)
- annual Customer Satisfaction Surveys

Environmental Expense:

In 2012, London Hydro is addressing an issue with lead contamination in its facility and vehicles which requires cleanup and a secure, safe place to store and work on lead. Lead is used in London Hydro's Electrical Underground Systems and Substation Maintenance departments to seal underground high voltage network electrical conductors. High levels of lead in the body can be very harmful and therefore proper containment, personal protective equipment and safe, secure storage is very important. Expenses have been incurred to create a lead storage work shop with a proper ventilation system, and security. At the time of writing this work was nearing completion. Costs are expected to approach $120,000 or twice the amount of the original forecast. London Hydro must clean up and complete the removal of the old lead shop in the fall of 2012. Clean up of several vehicles is also required.

Substations requiring environmental cleanup from 2013 to 2017 are:

- Substation 28 – 505 Nelson St.
- Substation 26 – 1101 King St.
- Substation 46 – 1309 King St
- Substation 48 – 2125 Trafalgar St (in front)

Cleanup of substation sites can take up to a year to complete and are often tied to decommissioning substations and entail multi-phased reviews: sampling, excavation, disposal and remediation. Phase I of the environment review is completed by an Environmental Consulting Engineer who researches and documents the past uses of the property. Aerial photos, property ownership and Ministry of the Environment records are used to assess chemicals and products used or manufactured on the site.

Arsenic, Boron, Hydrocarbons, PCB oils, Coal tar and other coal based products, are some of the common products that can be found on these old sites. From aerial photos and past records a basic location of some of these possible contaminants can be estimated.

Phase II involves taking the information gathered in the Phase I and tests the contamination. This involves ground water wells to determine leaching problems from other sites onto or from London Hydro property. Bore holes at possible high contamination locations and around the perimeter fence line help determine the types and extent of the contamination.

If there is a building involved it will also require testing by swab, patch and sample testing before it can be cleaned up. Products like asbestos and lead are commonly found in substations.

Phase III involves excavation and transport of contaminated soils for testing and a final determination of depth and volume of soil removal required. The Consulting Engineer works with the Ministry of the Environment and London Hydro to properly register the site, define the contaminates, and document the cleanup

Table 4-38 - Studies and On-Going Special Projects

SUMMARY OF STUDIES AND SPECIAL PROJECTS - SIGNIFICANT COST VARIANCES											
	CGAAP							MIFRS		CGAAP VARIANCE	
	2009 OEB Submission	2009 OEB Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST	2009 ACTUAL to 2013 TEST	
	$	$	$	$	$	$	$	$	$	$	%
Significant Expense & Cost Variances:											
Studies & Special Projects	89,000	89,000	58,380	60,454	53,631	105,000	105,000	105,000	105,000	46,620	79.9
Environmental Expenses	20,000	20,000	8,617	1,724	6,333	60,000	60,000	60,000	60,000	51,383	596.3
	109,000	109,000	66,996	62,178	59,964	165,000	165,000	165,000	165,000	98,004	146.3
Other Expense & Cost Variances:	-	-	-	-		-	-	-	-		
TOTAL EXPENSE & COST VARIANCE:	**109,000**	**109,000**	**66,996**	**62,178**	**59,964**	**165,000**	**165,000**	**165,000**	**165,000**	**98,004**	**146.3**

Allocation of Overhead to Capital and Billable Services:

London Hydro budgets and manages total costs by major cost category. All costs presented below are before any allocation to capital, billable, or other activities. The allocation of costs associated with material management and the fleet is accomplished with the use of overhead rates. Variances year to year are impacted by the cost associated with these two departments and the type and timing of capital and billable projects.

The allocation of costs to capital and billable activities will be impacted by the transition to MIFRS. A full discussion related to this impact is provided in the preceding commentary on Page 12 as well as in Exhibit 10, Page 11.

The Table 4-39, on Page 77 summarizes allocation levels for the period from 2009 Actual to the proposed 2013 Test Year.

Table 4-39 - Historical Allocation to Capital and Billable Activities

(CGAAP and MIFRS)

CGAAP			
Allocation to Capital and Billable Activities	$	Year on Year Change ($)	Year on Year Change (%)
2009 Actual	(1,658,543)		
2010 Actual	(1,890,069)	(231,526)	14.0%
2011 Actual	(2,136,291)	(246,222)	13.0%
2012 Bridge CGAAP	(2,382,100)	(245,809)	11.5%
2013 Test CGAAP	(2,547,700)	(165,600)	7.0%

MIFRS			
Allocation to Capital and Billable Activities	$	CGAAP to MIFRS Change ($)	CGAAP to MIFRS Change ($)
2012 Bridge	(1,697,400)	684,700	-32.1%
2013 Test	(1,810,700)	737,000	-43.4%

Cost Recoveries:

Certain costs incurred and discussed on a gross basis in the preceding discussion are recovered from various external sources. Table 4-40, on Page 78 provides details.

Costs recovered from the City of London are related to the provision of the water billing service. A full description of this arrangement and an external consulting review of the cost of this service is provided in the Section entitled "*Shared Services and Corporate Cost Allocation"* on Page 99 of this Exhibit. Costs recovered are expected to increase under a new service level agreement between London Hydro and the Corporation of the City of London. The proposed cost recovery for the 2013 Test Year is expected to be $3,950,000. This is an increase of $900,000 or 29.5% over the 2009 Board Approved level.

London Hydro's control centre provides service to the City of London. Recovery of $10,000 is expected to continue for the 2012 Bridge and proposed 2013 Test Years. This service includes after regular office hours support for customer inquiries related to water, and after hours creation of service orders and dispatch of waterworks personnel for water trouble calls, among others.

Collection fees recovered directly from London Hydro's customers are netted to collection cost for the rate application presentation (i.e. OEB 5330, Collection Charges). Collection charges are forecasted to be $648,000 and $667,000 for the 2012 Bridge and proposed 2013 Test Year respectively.

Other miscellaneous cost recoveries are related mainly to electric meter sealing activities as well as other non-recurring activities. Historical actuals include apprentice tax credits, however, a further review of the requirements for PILs indicates that these tax credits should be excluded from OM&A and included in the calculation of PILs. Historical actuals have not been restated. In addition to this, since all OPA program costs are to be excluded from OM&A, so are the associated recoveries and therefore they are excluded from the 2012 Bridge and proposed 2013 Test Years. This explains the decline in miscellaneous cost recoveries in those years.

Table 4-40 - Cost Recovery Details

Cost Recoveries	2009 TEST as Submitted	Board Decision Adj	2009 Board Approved	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST
		(Note 1)	CGAAP *(no MIFRS Impact)*					
City of London - Water Services	$(3,050,000)	$ -	$(3,050,000)	$(3,025,000)	$(3,025,000)	$(3,337,989)	$(3,550,000)	$(3,950,000)
City of London - Control Centre Services	(10,000)	-	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)	(10,000)
Collection Fees	(550,000)	-	(550,000)	(493,985)	(661,368)	(672,100)	(648,000)	(667,000)
Miscellaneous	(48,000)	(42,000)	(90,000)	(81,187)	(119,588)	(117,712)	(50,200)	(51,200)
TOTAL Cost Recoveries	$(3,658,000)	$(42,000)	$(3,700,000)	$(3,610,172)	$(3,815,956)	$(4,137,801)	$(4,258,200)	$(4,678,200)

Note 1 - In the 2009 Board Decision, an adjustment for recovery related to the apprentice tax program was added to the submitted recovery

OEB Uniform System of Accounts ("USoA") Variance Review:

As previously discussed, the variance analysis has been prepared from two different perspectives. The preceding variance analysis section has summarized costs and variances by the major cost category, such as labour, purchased services, and materials and supplies, among others.

The following variance review in OEB USoA format focuses on spending based on type of activity performed such as operating, maintenance, billing and collections, and administrative and general. Each activity is a mix of the various cost categories and is impacted by the same cost drivers, as described in detail on Pages 20 to 29.

London Hydro's financial system utilizes a different chart of accounts for internal management reporting purposes. This chart of accounts reflects the departmental operating structure of the organization and areas of management reporting responsibility, whereas, the OEB USoA is based on broad operating activities. London Hydro translates departmental operating accounts into the activity based OEB USoA account for regulatory reporting purposes. This "mapping" has been consistently applied, however, may require the allocation of a single operating cost over several USoA accounts and therefore includes prorated or estimated allocations.

Detailed, Account by Account OM&A Expense (OEB Appendix 2-G) is provided in Table 4-42, on Pages 83 to 87, and includes 2009, 2010 and 2011 Actuals, 2012 Bridge Year, and the proposed 2013 Test Year in both CGAAP and MIFRS formats. These Tables are presented in accordance with the Filing Requirements and include total OM&A costs including smart meters.

The OM&A Detailed Variance Analysis (OEB Appendix 2-H) is provided in Table 4-43 on Pages 88 to 92, and includes variances between the proposed 2013 Test Year and the Last Rebasing Year ("LRY") being 2009 as well as between the proposed 2013 Test Year and the most current Actual Year being 2011. Variances for the 2012 Bridge Year and 2013 Test Year are largely explained as a result of the inclusion of the smart meter program costs starting in 2012.

A summary, Table 4-41, on Page 80, is provided in USoA format for those OEB accounts with variances in excess of the threshold in accordance with the Filing Requirements. This threshold is established at $294,000 (see Exhibit 1, Table 1-23, Page 69).

Table 4-41 - USoA Accounts with Variances in Excess of Threshold

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year	VARIANCES: Threshold $294k 2009 - 2010 Actual	2010 - 2011 Actual	2011 Actual - 2012 BRIDGE	2012 BRIDGE - 2013 TEST
Reporting Basis		CGAAP					CGAAP			
		$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)	$(000)
5085	Miscellaneous Distribution Expenses	1,964	2,420	2,400	2,436	2,557	**456**	(20)	35	121
5125	Maintenance of Overhead Conductors and Devices	1,028	1,066	1,367	1,358	1,422	37	**301**	(8)	64
5335	Bad Debt Expense	825	1,120	800	1,000	1,000	**295**	**(320)**	200	-
5610	Management Salaries and Expenses	843	1,291	1,257	1,355	1,379	**449**	(35)	99	24
5615	General Administrative Salaries and Expenses	1,988	2,656	2,578	2,917	3,042	**668**	(79)	**339**	125
5630	Outside Services Employed	472	1,517	1,185	1,240	1,169	**1,045**	**(332)**	56	(72)

5085 Miscellaneous Distribution Expenses:

The variance for 2009 Actual – 2010 Actual: $456k.

The variance in Miscellaneous Distribution Expense is a result of multiple components. There was approximately $247k in cost increases related to snow removal, utilities, and minor renovations in 2010 compared to the previous year. The increased cost of outsourced locate services ($132k) have been offset with the reduction of internal labour required to perform this function with a net effect of $31k. Also, in 2010 an additional position was added (Instrumentation & Controls Technologist) in the Radio and Communications area accounting for approximately $105k of the overall increase.

5125 Maintenance of Overhead Conductors and Devices:

Variance for 2010 Actual – 2011 Actual: $301k

London Hydro conducts periodic audits on its distribution system. During 2011 the audit was concentrated on the core area of the City which is an older part of the distribution system. Higher maintenance costs were incurred due to the age of the infrastructure and the fact that a number of problems were found. Also, a very large number of copper ground wires were missing on poles due to theft, which is usually more prevalent in the core area of the City. The scope of the audit also included finding and replacing missing cable guards.

5335 Bad Debt Expense:

Year over Year Variances for 2009 Actual - 2010 Actual, and 2010 Actual - 2011 Actual: $295k increase and a $320k decrease, respectively.

The economic downturn and regulatory direction related to allowed collection practices caused an increase in bad debt expense during 2010. The recovery of the economy and improvements in collection practices resulted in improvements in 2011 although the total bad debt in 2011 remained significantly higher at $800k than the Board approved level in 2009 of $535k. A more in-depth discussion related to Bad Debt and the key impacts driving the variances is provided in the previous section entitled: "Bad Debt" beginning on Page 60.

5610 Management Salaries and Expenses and 5615 General and Administrative Salaries and Expenses:

Accounts 5610 and 5615 are both primarily related to labour costs and are grouped for the following variance review as similar discussions relate to both.

Variance for 2009 Actual – 2010 Actual: $449k and $668k

A new Project Management Office was established in early 2010 to provide oversight and coordination of all IT projects with new headcounts accounting for approximately $365k of the total increase.

The year 2010 was one of significance to London Hydro as it made ready for the transition to Smart Meters. New positions to support the increasingly complex information systems and new requirements of the daily operations are approximately $572k.

Wage escalation also contributed to the variance.

Variance for 2011 Actual – 2012 Bridge: $339k

The effect of the increase in skilled internal resources during 2012 is $334k in the information system area. Additional part-time position was required to perform in-house payment processing resulting in net increase of $37k in labour costs.

Wage escalation also contributed to the variance.

More in depth information on resource requirements can be found in the Staffing Levels discussion on Page 4, as well as in the Major Cost Categories Variance Review section starting on Page 35. This section provides detail related to variance in Labour and Benefit costs.

5630 Outside Services Employed:

Variance for 2009 Actual – 2010 Actual: $1,045k

During the year following the implementation of London Hydro's new SAP billing system increased contracted personnel was required to support the daily billing activities.

Variance for 2010 Actual – 2011 Actual: decrease of $332k

London Hydro has been modifying the mix of resources employed in the maintenance of the complex information systems to retain and improve in-house knowledge while reducing external resources.

More in depth discussions can be found in the Major Cost Categories Variance Review section of this Application starting on Page 35. The mix of outside services employed and the use of in-house staff is specifically discussed in Labour and Benefits and the Purchased Services variance sections found on Page 36 and Page 57, respectively.

Table 4-42 - Detailed, Account by Account, O&MA Expense Table

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – G)

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013	Test Year 2013
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP	MIFRS
Operations								
5005	Operation Supervision and Engineering	$ 1,258,994	$ 1,395,778	$ 1,636,095	$ 1,823,009	$ 1,823,009	$ 1,879,668	$ 1,924,935
5010	Load Dispatching	1,296,420	1,220,584	1,297,969	1,424,702	1,424,702	1,580,153	1,580,153
5012	Station Buildings and Fixtures Expense	221,313	219,793	195,112	225,382	225,382	226,631	226,631
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-
5015	Transformer Station Equipment - Operation Supplies and Expens	-	-	-	-	-	-	-
5016	Distribution Station Equipment - Operation Labour	152,951	119,253	165,190	167,940	167,940	162,547	162,547
5017	Distribution Station Equipment - Operation Supplies and Expens	458,250	303,181	363,340	352,394	458,606	346,028	454,931
5020	Overhead Distribution Lines and Feeders - Operation Labour	27,132	24,787	60,204	35,485	35,485	37,151	37,151
5025	Overhead Distribution Lines and Feeders - Operation Supplies &	438,331	304,447	308,813	288,127	392,503	300,932	407,951
5030	Overhead Sub-transmission Feeders - Operation	-	-	-	-	-	-	-
5035	Overhead Distribution Transformers - Operation	41,026	3,130	19,553	18,705	22,183	19,559	23,125
5040	Underground Distribution Lines and Feeders - Operation Labour	85,665	61,852	51,197	71,825	71,825	72,210	72,210
5045	Underground Distribution Lines and Feeders - Operation Supplie	76,915	52,243	49,603	51,161	65,606	52,824	67,635
5050	Underground Sub-transmission Feeders - Operation	-	-	-	-	-	-	-
5055	Underground Distribution Transformers - Operation	493,020	283,265	400,125	325,484	424,672	339,496	441,196
5060	Street Lighting and Signal System Expense	-	-	-	-	-	-	-
5065	Meter Expense	643,483	747,504	846,336	1,022,305	1,022,305	762,099	762,099
5070	Customer Premises - Operation Labour	-	-	-	-	-	-	-
5075	Customer Premises - Operation Materials and Expenses	-	-	-	-	-	-	-
5085	Miscellaneous Distribution Expenses	1,964,358	2,420,493	2,400,326	2,435,557	2,435,557	2,556,988	2,556,988
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-
5095	Overhead Distribution Lines and Feeders - Rental Paid	81,886	82,090	80,223	90,260	90,260	94,496	94,496
5096	Other Rent	-	-	-	-	-	-	-
Total - Operations		$ 7,239,743	$ 7,238,401	$ 7,874,084	$ 8,332,337	$ 8,660,037	$ 8,430,782	$ 8,812,049

Table 4-42 - Detailed, Account by Account, O&MA Expense Table Cont'd.

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – G)

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013	Test Year 2013
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP	MIFRS
Maintenance								
5105	Maintenance Supervision and Engineering	$ 1,050,377	$ 1,242,742	$ 1,420,801	$ 1,648,298	$ 1,648,298	$ 1,747,339	$ 1,702,072
5110	Maintenance of Buildings and Fixtures - Distribution Stations	45,280	44,335	92,967	66,053	66,053	67,009	67,009
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-
5114	Maintenance of Distribution Station Equipment	140,079	217,687	296,775	262,203	262,203	253,783	253,783
5120	Maintenance of Poles, Towers and Fixtures	715,826	696,114	494,639	692,563	692,563	725,065	725,065
5125	Maintenance of Overhead Conductors and Devices	1,028,495	1,065,656	1,366,596	1,358,234	1,358,234	1,421,976	1,421,976
5130	Maintenance of Overhead Services	146,430	177,095	207,094	188,518	188,518	197,365	197,365
5135	Overhead Distribution Lines and Feeders - Right of Way	581,897	647,810	785,017	882,700	882,700	920,100	920,100
5145	Maintenance of Underground Conduit	263,195	362,082	126,356	303,883	303,883	317,588	317,588
5150	Maintenance of Underground Conductors and Devices	805,664	880,178	1,125,571	912,040	912,040	950,176	950,176
5155	Maintenance of Underground Services	442,246	485,985	521,033	491,780	491,780	512,908	512,908
5160	Maintenance of Line Transformers	413,936	502,903	316,721	449,358	449,358	448,239	448,239
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-
5170	Sentinel Lights - Labour	-	-	-	-	-	-	-
5172	Sentinel Lights - Materials and Expenses	-	-	162	45	45	47	47
5175	Maintenance of Meters	9,792	66,007	28,453	277,781	277,781	275,364	275,364
5178	Customer Installations Expenses - Leased Property	-	-	-	-	-	-	-
5195	Maintenance of Other Installations on Customer Premises	-	-	-	-	-	-	-
Total - Maintenance		$ 5,643,217	$ 6,388,593	$ 6,782,183	$ 7,533,455	$ 7,533,455	$ 7,836,959	$ 7,791,693

1 **Table 4-42 - Detailed, Account by Account, O&MA Expense Table Cont'd.**

2 *(Excluding Depreciation and Amortization Expense)*

3 *(OEB Appendix 2 – G)*

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual[2]	Bridge Year 2012[3]	Bridge Year 2012[3]	Test Year 2013	Test Year 2013
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP	MIFRS
Billing and Collecting								
5305	Supervision	$ 88,553	$ 87,365	$ 85,214	$ 83,617	$ 83,617	$ 80,443	$ 80,443
5310	Meter Reading Expense	1,524,579	1,367,829	1,409,092	1,296,552	1,296,552	1,248,848	1,248,848
5315	Customer Billing	2,175,953	2,011,563	2,033,959	1,883,599	1,883,599	1,789,354	1,789,354
5320	Collecting	1,272,225	1,306,745	1,369,719	1,247,366	1,247,366	1,197,519	1,197,519
5325	Collecting - Cash Over and Short	-	-	-	-	-	-	-
5330	Collection Charges	(493,985)	(661,368)	(672,100)	(648,000)	(648,000)	(667,000)	(667,000)
5335	Bad Debt Expense	825,000	1,120,000	800,000	1,000,000	1,000,000	1,000,000	1,000,000
5340	Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-
Total - Billing and Collecting		$ 5,392,324	$ 5,232,134	$ 5,025,884	$ 4,863,134	$ 4,863,134	$ 4,649,165	$ 4,649,165
Community Relations								
5405	Supervision	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5410	Community Relations - Sundry	38,844	70,506	39,250	87,668	87,668	92,340	92,340
5415	Energy Conservation	219,195	90,165	34,025	-	-	-	-
5420	Community Safety Program	94,113	90,504	105,456	109,384	109,384	112,997	112,997
5425	Miscellaneous Customer Service and Informational Expenses	-	-	-	-	-	-	-
5505	Supervision	-	-	-	-	-	-	-
5510	Demonstrating and Selling Expense	-	-	-	-	-	-	-
5515	Advertising Expenses	-	-	-	-	-	-	-
5520	Miscellaneous Sales Expense	-	-	-	-	-	-	-
Total - Community Relations		$ 352,152	$ 251,175	$ 178,731	$ 197,052	$ 197,052	$ 205,337	$ 205,337

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Table 4-42 - Detailed, Account by Account, O&MA Expense Table Cont'd.

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – G)

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	Bridge Year 2012	Bridge Year 2012	Test Year 2013	Test Year 2013
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP	MIFRS
Administrative and General Expenses								
5605	Executive Salaries and Expenses	$ 1,047,992	$ 984,165	$ 1,066,582	$ 1,196,433	$ 1,196,433	$ 1,140,925	$ 1,140,925
5610	Management Salaries and Expenses	842,539	1,291,293	1,256,619	1,355,174	1,355,174	1,378,848	1,378,848
5615	General Administrative Salaries and Expenses	1,988,455	2,656,469	2,577,862	2,916,759	2,916,759	3,042,152	3,042,152
5620	Office Supplies and Expenses	1,039,106	1,114,368	1,222,633	1,255,779	1,255,779	1,225,718	1,225,718
5625	Administrative Expense Transferred - Credit	-	-	-	-	-	-	-
5630	Outside Services Employed	472,272	1,516,867	1,184,623	1,240,295	1,240,295	1,168,753	1,168,753
5635	Property Insurance	420,500	394,895	411,307	416,400	416,400	427,860	427,860
5640	Injuries and Damages	297,775	215,132	248,767	270,861	270,861	277,054	277,054
5645	OMERS Pensions and Benefits	133,685	182,541	223,313	246,543	246,543	249,208	249,208
5646	Employee Pensions and OPEB	-	-	-	-	-	-	-
5647	Employee Sick Leave	-	-	-	-	-	-	-
5650	Franchise Requirements	-	-	-	-	-	-	-
5655	Regulatory Expenses	571,922	408,819	389,494	523,000	523,000	537,700	537,700
5660	General Advertising Expenses	404,405	417,810	406,027	616,132	616,132	586,260	586,260
5665	Miscellaneous General Expenses	1,286,805	1,365,210	1,395,733	1,458,665	1,458,665	1,662,265	1,662,265
5670	Rent	-	-	-	-	-	-	-
5672	Lease Payment Charge	-	-	-	-	-	-	-
5675	Maintenance of General Plant	611,324	541,510	532,739	581,167	581,167	589,576	589,576
5680	Electrical Safety Authority Fees	-	-	-	-	-	-	-
5681	Special Purpose Charge Expense	-	-	-	-	-	-	-
5685	Independent Electricity System Operator Fees and Penalties	-	-	-	-	-	-	-
5695	OM&A Contra Account	-	-	-	-	-	-	-
6205	Donations	3,291	7,252	5,742	-	-	-	-
6205	Donations, Sub-account LEAP Funding	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Total - Administrative and General Expenses		$ 9,220,072	$ 11,196,330	$ 11,021,441	$ 12,177,207	$ 12,177,207	$ 12,386,320	$ 12,386,320
Total OM&A and Donations		$ 27,847,508	$ 30,306,634	$ 30,882,323	$ 33,103,186	$ 33,430,886	$ 33,508,563	$ 33,844,563

1 **Table 4-42 - Detailed, Account by Account, O&MA Expense Table Cont'd.**

2 *(Excluding Depreciation and Amortization Expense)*

3 *(OEB Appendix 2 – G)*

Account	Description	Last Rebasing Year (2009 Actuals)	2010 Actual	2011 Actual	Bridge Year 2012	Bridge Year 2012	Test Year 2013	Test Year 2013
Reporting Basis		CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	CGAAP	MIFRS
Adjustments for non-recoverable items								
5681	Special Purpose Charge Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6205	Donations[1]	3,291	7,252	5,742	-	-	-	-
Total Recoverable OM&A, and Donations		$ 27,844,217	$ 30,299,382	$ 30,876,581	$ 33,103,186	$ 33,430,886	$ 33,508,563	$ 33,844,563

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Table 4-43 - OM&A Detailed Variance Analysis

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – H)

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
						Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	CGAAP	MIFRS	CGAAP VARIANCES			
Operations									
5005	Operation Supervision and Engineering	$ 1,258,994	$ 1,636,095	$ 1,879,668	$ 1,924,935	$ 620,674	49.30%	$ 243,573	14.89%
5010	Load Dispatching	1,296,420	1,297,969	1,580,153	1,580,153	283,733	21.89%	282,184	21.74%
5012	Station Buildings and Fixtures Expense	221,313	195,112	226,631	226,631	5,318	2.40%	31,519	16.15%
5014	Transformer Station Equipment - Operation Labour	-	-	-	-	-		-	
5015	Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-		-	
5016	Distribution Station Equipment - Operation Labour	152,951	165,190	162,547	162,547	9,596	6.27%	(2,643)	-1.60%
5017	Distribution Station Equipment - Operation Supplies and Expenses	458,250	363,340	346,028	454,931	(112,221)	-24.49%	(17,311)	-4.76%
5020	Overhead Distribution Lines and Feeders - Operation Labour	27,132	60,204	37,151	37,151	10,019	36.93%	(23,053)	-38.29%
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Exp	438,331	308,813	300,932	407,951	(137,400)	-31.35%	(7,881)	-2.55%
5030	Overhead Sub-transmission Feeders - Operation	-	-	-	-	-		-	
5035	Overhead Distribution Transformers - Operation	41,026	19,553	19,559	23,125	(21,467)	-52.33%	6	0.03%
5040	Underground Distribution Lines and Feeders - Operation Labour	85,665	51,197	72,210	72,210	(13,454)	-15.71%	21,013	41.04%
5045	Underground Distribution Lines and Feeders - Operation Supplies and Exp	76,915	49,603	52,824	67,635	(24,091)	-31.32%	3,222	6.49%
5050	Underground Sub-transmission Feeders - Operation	-	-	-	-	-		-	
5055	Underground Distribution Transformers - Operation	493,020	400,125	339,496	441,196	(153,524)	-31.14%	(60,629)	-15.15%
5060	Street Lighting and Signal System Expense	-	-	-	-	-		-	
5065	Meter Expense	643,483	846,336	762,099	762,099	118,616	18.43%	(84,237)	-9.95%
5070	Customer Premises - Operation Labour	-	-	-	-	-		-	
5075	Customer Premises - Operation Materials and Expenses	-	-	-	-	-		-	
5085	Miscellaneous Distribution Expenses	1,964,358	2,400,326	2,556,988	2,556,988	592,631	30.17%	156,663	6.53%
5090	Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-		-	
5095	Overhead Distribution Lines and Feeders - Rental Paid	81,886	80,223	94,496	94,496	12,610	15.40%	14,273	17.79%
5096	Other Rent	-	-	-	-	-		-	
Total - Operations		$ 7,239,743	$ 7,874,084	$ 8,430,782	$ 8,812,049	$ 1,191,039	16.45%	$ 556,698	7.07%

Table 4-43 - OM&A Detailed Variance Analysis Cont'd.

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – H)

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
						Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	CGAAP	MIFRS	CGAAP VARIANCES			
Maintenance									
5105	Maintenance Supervision and Engineering	$ 1,050,377	$ 1,420,801	$ 1,747,339	$ 1,702,072	$ 696,962	66.35%	$ 326,538	22.98%
5110	Maintenance of Buildings and Fixtures - Distribution Stations	45,280	92,967	67,009	67,009	21,729	47.99%	(25,958)	-27.92%
5112	Maintenance of Transformer Station Equipment	-	-	-	-	-		-	
5114	Maintenance of Distribution Station Equipment	140,079	296,775	253,783	253,783	113,704	81.17%	(42,992)	-14.49%
5120	Maintenance of Poles, Towers and Fixtures	715,826	494,639	725,065	725,065	9,239	1.29%	230,426	46.58%
5125	Maintenance of Overhead Conductors and Devices	1,028,495	1,366,596	1,421,976	1,421,976	393,481	38.26%	55,380	4.05%
5130	Maintenance of Overhead Services	146,430	207,094	197,365	197,365	50,935	34.78%	(9,729)	-4.70%
5135	Overhead Distribution Lines and Feeders - Right of Way	581,897	785,017	920,100	920,100	338,203	58.12%	135,083	17.21%
5145	Maintenance of Underground Conduit	263,195	126,356	317,588	317,588	54,393	20.67%	191,233	151.34%
5150	Maintenance of Underground Conductors and Devices	805,664	1,125,571	950,176	950,176	144,512	17.94%	(175,395)	-15.58%
5155	Maintenance of Underground Services	442,246	521,033	512,908	512,908	70,663	15.98%	(8,124)	-1.56%
5160	Maintenance of Line Transformers	413,936	316,721	448,239	448,239	34,303	8.29%	131,518	41.52%
5165	Maintenance of Street Lighting and Signal Systems	-	-	-	-	-		-	
5170	Sentinel Lights - Labour	-	-	-	-	-		-	
5172	Sentinel Lights - Materials and Expenses	-	162	47	47	47		(115)	-70.99%
5175	Maintenance of Meters	9,792	28,453	275,364	275,364	265,572	2712.13%	246,911	867.79%
5178	Customer Installations Expenses - Leased Property	-	-	-	-	-		-	
5195	Maintenance of Other Installations on Customer Premises	-	-	-	-	-		-	
Total - Maintenance		$ 5,643,217	$ 6,782,183	$ 7,836,959	$ 7,791,693	$ 2,193,742	38.87%	$ 1,054,776	15.55%

Table 4-43 - OM&A Detailed Variance Analysis Cont'd.

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – H)

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
						Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	CGAAP	MIFRS	CGAAP VARIANCES			
Billing and Collecting									
5305	Supervision	$ 88,553	$ 85,214	$ 80,443	$ 80,443	$ (8,110)	-9.16%	$ (4,771)	$ (0)
5310	Meter Reading Expense	1,524,579	1,409,092	1,248,848	1,248,848	(275,731)	-18.09%	(160,244)	-11.37%
5315	Customer Billing	2,175,953	2,033,959	1,789,354	1,789,354	(386,599)	-17.77%	(244,605)	-12.03%
5320	Collecting	1,272,225	1,369,719	1,197,519	1,197,519	(74,705)	-5.87%	(172,200)	-12.57%
5325	Collecting - Cash Over and Short	-	-	-	-	-		-	
5330	Collection Charges	(493,985)	(672,100)	(667,000)	(667,000)	(173,015)	35.02%	5,100	-0.76%
5335	Bad Debt Expense	825,000	800,000	1,000,000	1,000,000	175,000	21.21%	200,000	25.00%
5340	Miscellaneous Customer Accounts Expenses	-	-	-	-	-		-	
Total - Billing and Collecting		$ 5,392,324	$ 5,025,884	$ 4,649,165	$ 4,649,165	$ (743,160)	-13.78%	$ (376,719)	-7.50%
Community Relations									
5405	Supervision	$ -	$ -	$ -	$ -	$ -		$ -	
5410	Community Relations - Sundry	38,844	39,250	92,340	92,340	53,496	137.72%	53,090	135.26%
5415	Energy Conservation	219,195	34,025	-	-	(219,195)	-100.00%	(34,025)	-100.00%
5420	Community Safety Program	94,113	105,456	112,997	112,997	18,884	20.07%	7,540	7.15%
5425	Miscellaneous Customer Service and Informational Expenses	-	-	-	-	-		-	
5505	Supervision	-	-	-	-	-		-	
5510	Demonstrating and Selling Expense	-	-	-	-	-		-	
5515	Advertising Expenses	-	-	-	-	-		-	
5520	Miscellaneous Sales Expense	-	-	-	-	-		-	
Total - Community Relations		$ 352,152	$ 178,731	$ 205,337	$ 205,337	$ (146,815)	-41.69%	$ 26,605	14.89%

Table 4-43 - OM&A Detailed Variance Analysis Cont'd.

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – H)

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
						Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	CGAAP	MIFRS	CGAAP VARIANCES			
Administrative and General Expenses									
5605	Executive Salaries and Expenses	$ 1,047,992	$ 1,066,582	$ 1,140,925	$ 1,140,925	$ 92,933	8.87%	$ 74,343	6.97%
5610	Management Salaries and Expenses	842,539	1,256,619	1,378,848	1,378,848	536,309	63.65%	122,229	9.73%
5615	General Administrative Salaries and Expenses	1,988,455	2,577,862	3,042,152	3,042,152	1,053,697	52.99%	464,291	18.01%
5620	Office Supplies and Expenses	1,039,106	1,222,633	1,225,718	1,225,718	186,613	17.96%	3,085	0.25%
5625	Administrative Expense Transferred - Credit	-	-	-	-	-		-	
5630	Outside Services Employed	472,272	1,184,623	1,168,753	1,168,753	696,481	147.47%	(15,869)	-1.34%
5635	Property Insurance	420,500	411,307	427,860	427,860	7,360	1.75%	16,554	4.02%
5640	Injuries and Damages	297,775	248,767	277,054	277,054	(20,722)	-6.96%	28,287	11.37%
5645	OMERS Pensions and Benefits	133,685	223,313	249,208	249,208	115,523	86.42%	25,895	11.60%
5646	Employee Pensions and OPEB	-	-	-	-	-		-	
5647	Employee Sick Leave	-	-	-	-	-		-	
5650	Franchise Requirements	-	-	-	-	-		-	
5655	Regulatory Expenses	571,922	389,494	537,700	537,700	(34,222)	-5.98%	148,206	38.05%
5660	General Advertising Expenses	404,405	406,027	586,260	586,260	181,855	44.97%	180,233	44.39%
5665	Miscellaneous General Expenses	1,286,805	1,395,733	1,662,265	1,662,265	375,460	29.18%	266,532	19.10%
5670	Rent	-	-	-	-	-		-	
5672	Lease Payment Charge	-	-	-	-	-		-	
5675	Maintenance of General Plant	611,324	532,739	589,576	589,576	(21,749)	-3.56%	56,837	10.67%
5680	Electrical Safety Authority Fees	-	-	-	-	-		-	
5681	Special Purpose Charge Expense	-	-	-	-	-		-	
5685	Independent Electricity System Operator Fees and Penalties	-	-	-	-	-		-	
5695	OM&A Contra Account	-	-	-	-	-		-	
6205	Donations	3,291	5,742	-	-	(3,291)	-100.00%	(5,742)	-100.00%
6205	Donations, Sub-account LEAP Funding	100,000	100,000	100,000	100,000	-	0.00%	0	0.00%
Total - Administrative and General Expenses		$ 9,220,072	$ 11,021,441	$ 12,386,320	$ 12,386,320	$ 3,166,248	34.34%	$ 1,364,880	12.38%

Table 4-43 - OM&A Detailed Variance Analysis Cont'd.

(Excluding Depreciation and Amortization Expense)

(OEB Appendix 2 – H)

Account	Description	Last Board-approved Rebasing Year (2009 Year)	Most Current Actuals Year 2011	Test Year 2013	Test Year 2013	Test Year Versus Last Rebasing		Test Year Versus Most Current Actuals	
						Variance ($)	Percentage Change (%)	Variance ($)	Percentage Change (%)
Reporting Basis		CGAAP	CGAAP	CGAAP	MIFRS	CGAAP VARIANCES			
Total OM&A		$ 27,847,508	$ 30,882,323	$ 33,508,563	$ 33,844,563	$ 5,661,055	20.33%	$ 2,626,240	8.50%
Adjustments for non-recoverable items									
5681	Special Purpose Charge Expense	-	-	-	-	-		-	
6205	Donations	3,291	5,742	-	-	(3,291)	-100.00%	(5,742)	-100.00%
						-		-	
						-		-	
						-		-	
Total Recoverable OM&A		$ 27,844,217	$ 30,876,581	$ 33,508,563	$ 33,844,563	$ 5,664,346	20.34%	$ 2,631,982	8.52%

Table 4-44 - Summary of Recoverable OM&A Expense

(OEB Appendix 2-I)

	Last Rebasing Year (2009 Board Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Operations	$ 7,270,764	$ 7,239,743	$ 7,238,401	$ 7,874,084	$ 8,332,337	$ 8,430,782	$ 8,660,037	$ 8,812,049
Maintenance	6,323,653	5,643,217	6,388,593	6,782,183	7,533,455	7,836,959	7,533,455	7,791,693
SubTotal	**$ 13,594,417**	**$ 12,882,960**	**$ 13,626,995**	**$ 14,656,267**	**$ 15,865,792**	**$ 16,267,742**	**$ 16,193,492**	**$ 16,603,742**
%Change (year over year)			5.8%	7.6%	8.3%	2.5%	10.5%	2.5%
% Change (Test Year vs Last Rebasing Year - Actual)						26.3%		28.9%
Billing and Collecting	$ 4,927,700	$ 5,392,324	$ 5,232,134	$ 5,025,884	$ 4,863,134	$ 4,649,165	$ 4,863,134	$ 4,649,165
Community Relations	316,579	352,152	251,175	178,731	197,052	205,337	197,052	205,337
Administrative and General	9,452,967	9,216,781	11,189,078	11,015,699	12,177,207	12,386,320	12,177,207	12,386,320
SubTotal	**$ 14,697,246**	**$ 14,961,257**	**$ 16,672,387**	**$ 16,220,314**	**$ 17,237,394**	**$ 17,240,821**	**$ 17,237,394**	**$ 17,240,821**
% Change (year over year)			11.4%	-2.7%	6.3%	0.0%	6.3%	0.0%
% Change (Test Year vs Last Rebasing Year - Actual)						15.2%		15.2%
Total	**$ 28,291,663**	**$ 27,844,217**	**$ 30,299,382**	**$ 30,876,581**	**$ 33,103,186**	**$ 33,508,563**	**$ 33,430,886**	**$ 33,844,563**
% Change (year over year)			8.8%	1.9%	7.2%	1.2%	8.3%	1.2%

	Last Rebasing Year (2009 Board Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year	2012 Bridge Year	2013 Test Year
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**
Operations	$ 7,270,764	$ 7,239,743	$ 7,238,401	$ 7,874,084	$ 8,332,337	$ 8,430,782	$ 8,660,037	$ 8,812,049
Maintenance	6,323,653	5,643,217	6,388,593	6,782,183	7,533,455	7,836,959	7,533,455	7,791,693
Billing and Collecting	4,927,700	5,392,324	5,232,134	5,025,884	4,863,134	4,649,165	4,863,134	4,649,165
Community Relations	316,579	352,152	251,175	178,731	197,052	205,337	197,052	205,337
Administrative and General	9,452,967	9,216,781	11,189,078	11,015,699	12,177,207	12,386,320	12,177,207	12,386,320
Total	**$ 28,291,663**	**$ 27,844,217**	**$ 30,299,382**	**$ 30,876,581**	**$ 33,103,186**	**$ 33,508,563**	**$ 33,430,886**	**$ 33,844,563**
% Change (year over year)			8.8%	1.9%	7.2%	1.2%	8.3%	1.2%

EMPLOYEE COMPENSATION BREAKDOWN

Table 4-45, on Page 96 is provided with details for the total number of employees, expressed in full time equivalents (“FTEs”), average base salary, average variable compensation, average overtime, and average benefits by employee groups.

Additional information related to variances in labour, benefits, and allocations to capital can be found beginning on Page 36 of this Exhibit.

The 2012 Bridge and proposed 2013 Test Years assume that new employees will be hired in January of each year.

Pay-for-Performance Plan

London Hydro’s compensation package includes both fixed and variable components. Table 4-45, on Page 96 provides information related to the average variable compensation by employee group. The 2009 Test Year as submitted did not include any variable compensation element; however, variable compensation has been paid in each of the years 2009 to 2011. The 2012 Bridge and proposed 2013 Test Year includes expected variable compensation of $300,000 annually.

Each year, in conjunction with the budget development the Executive Committee, comprised of the CEO, CFO, VP, Engineering and Operations, and VP, Corporate Services, meet with the London Hydro Board of Directors to review and update London Hydro’s Strategic Plan. The Plan (Exhibit 1, Appendix 1A) identifies the Corporations goals within strategic areas. The current plan identifies six strategic areas:

- Distribution Systems and Technology
- Financial and Regulatory
- Human Resources
- Customer Service
- Green Energy
- Community Relations

Once established for the year, the Executive Committee, with their management staff, establish quarterly targets designed to meet the corporate goals and expectations. Typically, there are approximately 5 or 6 quarterly targets within each strategic area. Progress toward the targets is measured quarterly by the Board of Directors and a numerical score, depending on the level of success in meeting each target is applied. At the end of the 4th quarter, the total score for the year for all the targets is summed and incentive pay is awarded based on the total score for the year. For example, a score of 85% would mean that eligible employees would earn 85% of their incentive target.

Compensation Studies

Every other year London Hydro initiates or participates in, in-depth salary surveys of Executive and Management salaries to ensure that compensation remains competitive with its peers. It is London Hydro's practice to pay in the middle of the reported salary range. The last Executive Salary Survey was in 2011. London Hydro also participates in the EDA's Annual Salary Survey for non-union staff.

London Hydro management also utilizes other commercially available surveys including those from Mercer's and the Hay Group.

The latest study related to Management salaries is provided in Appendix 4B.

Actuarial Report for Post-Retirement Obligations

Annually, London Hydro engages an external consultant to complete an actuarial study related to the post-retirement benefit and accrued liability. Appendix 4C contains the most recent study completed on February 7, 2012.

The information which is disclosed in the "*Taxes or Payments In Lieu of Taxes (PILs)"* section agrees with this analysis.

The accrued benefit liability as calculated by the actuary for financial reporting purposes under CGAAP at December 31, 2011 was $10,640,200. See Exhibit 10, Page 17 for the differences under IFRS. As a result of these significant transitional adjustments London Hydro is requesting that a variance account be established.

Table 4-45 - Employee Compensation Breakdown

(OEB Appendix 2-K)

Item	Last Rebasing Year*** 2009	Actual 2009	Actual 2010	Actual 2011	Bridge Year (CGAAP) 2012	Test Year (MIFRS) 2013
Number of Employees (FTEs including Part-Time)						
Executive	14.0	13.8	14.8	16.1	16.0	16.0
Management	36.0	34.1	30.7	32.3	36.0	36.0
Non-Union	35.0	32.7	38.2	37.7	46.0	48.0
Union	176.0	168.4	165.1	177.0	188.0	188.0
Non-Permanent	17.9	24.0	33.3	27.7	37.7	31.5
Total	**278.9**	**273.0**	**282.1**	**290.8**	**323.7**	**319.5**
Number of Part-Time Employees (FTEs)						
Executive						
Management						
Non-Union	7.4	5.2	7.5	9.0	14.5	15.6
Union	10.5	18.8	25.8	18.7	23.2	15.9
Total	**17.9**	**24.0**	**33.3**	**27.7**	**37.7**	**31.5**
Total Salary and Wages						
Executive	1,904,500	1,683,320	1,912,524	2,143,976	2,217,716	2,239,266
Management	3,056,100	2,969,782	2,836,137	2,946,297	3,333,458	3,446,939
Non-Union	2,630,700	2,521,953	3,036,176	2,938,402	3,718,076	4,014,067
Union	10,902,500	10,531,648	10,644,915	11,450,503	12,546,351	12,933,468
Non-Permanent	698,900	1,019,399	1,387,354	1,277,383	1,789,600	1,627,761
Total	**19,192,700**	**18,726,102**	**19,817,107**	**20,756,561**	**23,605,200**	**24,261,500**
Current Benefits						
Executive	335,125	350,685	406,728	444,048	509,931	519,035
Management	646,106	664,315	706,034	663,884	793,217	849,951
Non-Union	588,278	599,250	702,020	727,731	889,086	1,019,011
Union	3,032,891	2,860,912	3,136,026	3,071,139	3,677,280	3,810,251
Non-Permanent	84,000	83,868	122,328	166,483	153,286	214,752
Total	**4,686,400**	**4,559,030**	**5,073,136**	**5,073,285**	**6,022,800**	**6,413,000**
Accrued Pension and Post-Retirement Benefits						
Executive	95,453	88,871	101,865	146,271	116,430	116,407
Management	153,170	135,956	134,397	180,519	158,588	162,487
Non-Union	131,849	115,246	143,513	178,439	176,107	188,379
Union	546,428	476,522	500,112	692,287	591,475	604,328
Non-Permanent	-	-	-	-	-	-
Total	**926,900**	**816,594**	**879,886**	**1,197,516**	**1,042,600**	**1,071,600**
Total Benefits (Current + Accrued)						
Executive	430,578	439,556	508,593	590,320	626,361	635,441
Management	799,277	800,271	840,430	844,403	951,805	1,012,438
Non-Union	720,127	714,496	845,533	906,170	1,065,193	1,207,390
Union	3,579,318	3,337,434	3,636,139	3,763,426	4,268,755	4,414,579
Non-Permanent	84,000	83,868	122,328	166,483	153,286	214,752
Total	**5,613,300**	**5,375,625**	**5,953,022**	**6,270,801**	**7,065,400**	**7,484,600**
Total Compensation (Salary, Wages, & Benefits)						
Executive	2,335,078	2,122,876	2,421,117	2,734,296	2,844,077	2,874,707
Management	3,855,377	3,770,053	3,676,567	3,790,700	4,285,263	4,459,376
Non-Union	3,350,827	3,236,448	3,881,709	3,844,572	4,783,268	5,221,457
Union	14,481,818	13,869,082	14,281,054	15,213,929	16,815,106	17,348,047
Non-Permanent	782,900	1,103,267	1,509,682	1,443,866	1,942,886	1,842,513
Total	**24,806,000**	**24,101,727**	**25,770,129**	**27,027,363**	**30,670,600**	**31,746,100**

Table 4-45 - Employee Compensation Breakdown, *Continued*

(OEB Appendix 2-K)

Item	Last Rebasing Year***	Actual	Actual	Actual	Bridge Year	Test Year
	2009	2009	2010	2011	2012	2013
Overtime by Group						
Executive	-	-	-	-	-	-
Management	126,500	91,677	90,233	184,519	109,063	110,242
Non-Union	6,900	19,978	10,950	32,538	18,869	19,073
Union	926,900	1,125,621	1,131,885	1,217,239	1,058,109	1,069,545
Non-Permanent	-	2,841	11,615	10,658	7,559	7,641
Total	**1,060,300**	**1,240,116**	**1,244,682**	**1,444,954**	**1,193,600**	**1,206,500**
Incentive Pay by Group						
Executive	-	280,825	255,668	275,368	252,000	252,000
Management	-	35,000	24,500	39,500	30,500	30,500
Non-Union	-	25,100	18,500	13,000	17,500	17,500
Union	-	-	-	-	-	-
Non-Permanent	-	-	-	-	-	-
Total	**-**	**340,925**	**298,668**	**327,868**	**300,000**	**300,000**
Compensation - Average Yearly Base Wages						
Executive	136,036	122,041	128,884	133,166	138,607	139,954
Management	84,892	87,075	92,310	91,217	92,596	95,748
Non-Union	75,163	77,067	79,426	77,942	80,828	83,626
Union	61,946	62,551	64,492	64,692	66,736	68,795
Non-Permanent	39,045	42,495	41,675	46,115	47,523	51,695
Total	**397,081**	**391,229**	**406,787**	**413,132**	**426,290**	**439,819**
Compensation - Average Yearly Overtime						
Executive	-	-	-	-	-	-
Management	3,514	2,688	2,937	5,713	3,030	3,062
Non-Union	197	610	286	863	410	397
Union	5,266	6,685	6,858	6,877	5,628	5,689
Non-Permanent	-	118	349	385	201	243
Total	**8,978**	**10,102**	**10,430**	**13,838**	**9,269**	**9,391**
Compensation - Average Yearly Incentive Pay						
Executive	-	20,360	17,229	17,104	15,750	15,750
Management	-	1,026	797	1,223	847	847
Non-Union	-	767	484	345	380	365
Union	-	-	-	-	-	-
Non-Permanent	-	-	-	-	-	-
Total	**-**	**22,153**	**18,511**	**18,671**	**16,978**	**16,962**
Compensation - Average Yearly Benefits						
Executive	30,756	31,868	34,274	36,666	39,148	39,715
Management	22,202	23,464	27,354	26,143	26,439	28,123
Non-Union	20,575	21,834	22,119	24,036	23,156	25,154
Union	20,337	19,822	22,030	21,262	22,706	23,482
Non-Permanent	4,693	3,496	3,675	6,010	4,071	6,820
Total	**98,563**	**100,484**	**109,451**	**114,117**	**115,520**	**123,294**
Total Compensation	$25,866,300	$25,682,768	$27,313,479	$28,800,184	$32,164,200	$33,252,600
Total Compensation Capitalized (CGAAP)	$ 6,472,600	$ 6,746,630	$ 6,913,533	$ 7,931,964	$ 9,613,800	
Total Compensation Charged to OM&A (CGAAP)	$19,393,700	$18,936,138	$20,399,946	$20,868,220	$22,550,400	
Total Compensation Capitalized (MIFRS)						$10,166,700
Total Compensation Charged to OM&A (MIFRS)				$28,800,184	$32,164,200	$23,085,900

SHARED SERVICES and CORPORATE COST ALLOCATION

Renewable Generation:

Background:

In 2010, London Hydro made the decision to invest in some renewable generation activities. As a result, London Hydro began to purchase a total of ten solar panel stations with one additional project planned for 2013. These projects consist of both mounted rooftop panels and ground mounted tracking panels.

Work commenced in 2010 and the first installation was completed in 2011 when the stations were energized and connected to the grid. The final proposed project is expected to be energized in the summer of 2013.

Analysis and Assumptions:

As London Hydro does not have any other affiliated businesses, all of the costs and revenues from these non-regulated activities are included in the financial results of the company. As required, these non-distribution related revenues and expenses have been removed from analysis for rate application purposes.

In addition to the actual third party costs incurred, the following steps were taken to ensure that the interactions between the distribution and generation activities were carried out in a manner similar to that contemplated by the Board in the Affiliate Relationship Code ("ARC") which governs interactions between licensed distributors and their affiliates.

1. Any amounts owing to or from the rate regulated portion of the business from the renewable generation project have been charged at the same rates as provided by the bank. (Prime – 1.75%).

   The average balance outstanding using the simple formula (beginning of year + end of year before interest/ 2) was used to determine the average balance. The average balance was then multiplied by the prime rate (at December 31) less 1.75% to determine the interest expense. This is the actual amount paid by the bank to keep funds on hand. As such, the non-regulated business is paying the amount the rate regulated business would have made by having these funds in the bank.

For purposes of this Application, the interest rate utilized as of December 31, 2011 was utilized for the 2012 and 2013 balances.

2. As the generation project does not have separate staff to compile the results of the financial activities, perform any of the administrative functions required or to incur any of the overhead costs, the renewable generation company pays 2% of all external costs including capital expenditures to the rate regulated business to cover the costs of these functions.

Table 4-47, Page 103 provides proforma financial statements for the historical actuals (2010 and 2011) as well for the 2012 Bridge and 2013 Test Years.

Corporate Cost Allocation:

London Hydro does not have any retail affiliates; however, by virtue of the definition under the Ontario *Business Corporations Act*, the sole shareholder of London Hydro, the Corporation of the City of London, is an affiliated body corporate.

London Hydro provides certain services to the City. These services are provided on a full cost recovery basis or at market rates where market pricing is available. There is no cross-subsidy of costs with respect to services provided to the shareholder affiliate.

The total cost allocation for each of the following services is provided in Table 4-46 (OEB Appendix 2-L), on Page 102.

Rental of surplus office and shop space:

A rental rate, currently $23.12 per square foot, has been established and is based upon the actual operating cost per square foot of owning and maintaining the facilities plus a fair market value rental charge for similar facilities. The operating cost element is determined from actual operating expense accounts including depreciation, insurance, staffing costs, security, taxes, etc. It is not expected that the City would continue to occupy the space past 2011. The 2011 actual and 2012 projected recovery are $14,900 and $nil respectively. This cost recovery is credited to OEB account 4210, rent from electric property.

Provision of water billing services:

Water billing services are provided to the City on a full cost recovery basis, which includes labour, benefits, overhead, materials, equipment, information services, mailing and postage, and all other identifiable costs.

In 2012, London Hydro had a third party complete a full analysis of the cost of providing this water billing service as required by the Board Decision EB-2008-0235. The Navigant Cost of Service Study, dated April 5, 2012, has been applied to the Board Secretary for consideration under the Board's Practice Direction on Confidential Filings (the "Practice Direction"). The study was based on actual 2010 data adjusted for known and measurable changes. An example of a known and measurable change included in the report is the meter reading expense. London Hydro previously used an outside vendor to perform meter reading. With the introduction of smart meters the majority of these costs will be eliminated and therefore the elimination of these costs was factored into the model even though they were reported in the 2010 data.

The report indicates that the net value of the services provided to the City of London for water billing services is $3,470,000 ($2.69 per bill) per year while the actual incremental cost for London Hydro providing this service is estimated at $1,030,000 per year.

The agreement between the City of London and London Hydro is still being finalized.

The agreement is drafted to indicate that the City will pay $3,500,000 for the water billing services and will also pay any amounts collected relating to items such as the recoverable costs such as late payment charges will be net settled in addition to the flat $3,500,000 yearly fee. The expected recoveries for these amounts are expected to be $250,000 (2012 and 2013). The actual 2011 late payment charges for water were $287,989. The new cost sharing agreement is expected to be signed and in place for January 1, 2013.

Although London Hydro is still in negotiation with the City of London, London Hydro has included the expected cost recoveries (on a gross basis) from the City of $3,750,000 within this application.

The current signed cost sharing agreement has remained unchanged since 2010 as it has been known that London Hydro was required to obtain the third party report. It was determined that the agreement would be updated when the report had been finalized. As a result, the amount included in the 2011 Actuals and expected for 2012 are $3,337,989 and $3,300,000 respectively which represents the $3,050,000 net amount paid by the City plus the late payment charges associated with water billings.

The cost for the service which was identified in the study as the avoidable costs is $1,030,000. Based on the actual amounts collected and retained by London Hydro from the City of London for this service a return ranging from 224% (2011) to an expected 264% (2013) has been realized.

Control Centre After Hours Support:

London Hydro continues to provide after-hours support for the waterworks department of the City of London. This service involves answering customer water inquiries, and dispatching waterworks personnel as required after normal business hours. As London Hydro's control centre is manned 24-7, no additional cost is incurred related to the provision of this service. The City of London is billed $10,000 annually for this service.

Other Shared Services:

London Hydro does not purchase or provide any other services to, or receive any services from the Corporation of the City of London.

Land Rental:

The operation centre and business offices of London Hydro, located at 111 Horton Street, are located on lands that are owned by the City. Consistent with the agreement signed in 1994 between the City of London and London Hydro, London Hydro pays $100,000 annually to the City for the use of the land. As the land is owned by the City of London there is no "cost" to the City (excluding any property taxes which would be due to themselves and/or any potential mortgage payments required on the land value). As London Hydro is not aware of any actual costs the City is required to pay for this land, it has recorded the actual cost at $ nil in the Board's Appendix 2-L, referred to in this Application as Table 4-46, below.

Table 4-46 - Shared Services and Corporate Cost Allocation

(OEB Appendix 2-L)

Name of Company		Service Offered	Pricing Methdology	Price for the Service	Cost for the Service	Percentage Allocation
2009 Actual						
From	To			$	$	%
London Hydro	City of London	Water billing services	Fully allocated cost	3,025,000	1,030,000	193.7%
City of London	London Hydro	Rent	Market Value	100,000	-	100.0%
London Hydro	City of London	Rental of Office space	Market Value	113,455	103,700	9.4%
London Hydro	City of London	Control Centre - water support	Fully allocated cost	10,000	-	100.0%
			TOTAL:	3,248,455	1,133,700	186.5%
2010 Actual						
From	To			$	$	%
London Hydro	City of London	Water billing services	Fully allocated cost	3,025,000	1,030,000	193.7%
City of London	London Hydro	Rent	Market Value	100,000		100.0%
London Hydro	City of London	Rental of Office space	Market Value	118,237	106,800	10.7%
London Hydro	City of London	Control Centre - water support	Fully allocated cost	10,000	-	100.0%
			TOTAL:	3,253,237	1,136,800	186.2%
2011 ACTUAL						
From	To			$	$	%
London Hydro	City of London	Water billing services	Fully allocated cost	3,337,989	1,030,000	224.1%
City of London	London Hydro	Rent	Market Value	100,000	-	100.0%
London Hydro	City of London	Rental of Office space	Market Value	27,827	22,224	25.2%
London Hydro	City of London	Control Centre - water support	Fully allocated cost	10,000	-	100.0%
			TOTAL:	3,475,816	1,052,224	230.3%
2012 BRIDGE						
From	To			$	$	%
London Hydro	City of London	Water billing services	Fully allocated cost	3,300,000	1,030,000	220.4%
City of London	London Hydro	Rent	Market Value	100,000	-	100.0%
London Hydro	City of London	Control Centre - water support	Fully allocated cost	10,000	-	100.0%
			TOTAL:	3,410,000	1,030,000	231.1%
2013 TEST						
From	To			$	$	%
London Hydro	City of London	Water billing services	Fully allocated cost	3,750,000	1,030,000	264.1%
City of London	London Hydro	Rent	Market Value	100,000	-	100.0%
London Hydro	City of London	Control Centre - water support	Fully allocated cost	10,000	-	100.0%
			TOTAL:	3,860,000	1,030,000	274.8%

Table 4-47 - Renewable Generation Proforma Financial Statements

RENEWABLE GENERATION PROFORMA FINANCIAL STATEMENTS
(CGAAP)

Balance Sheet	**2010**	**2011**	**2012**	**2013**
ASSETS				
Cash	$ -	$ -	$ -	$ -
AR	-	-	-	-
Current Assets	-	-	-	-
Capital Assets	-	903,416	3,635,404	4,479,642
TOTAL ASSETS	**$ -**	**$ 903,416**	**$ 3,635,404**	**$ 4,479,642**
LIABILITIES				
Due to LDC	$ 22,692	$ 920,372	$ 3,702,463	$ 4,604,420
EQUITY				
Retained Earnings	(22,692)	(16,956)	(67,059)	(124,778)
TOTAL LIABILITIES & EQUITY	**$ -**	**$ 903,416**	**$ 3,635,404**	**$ 4,479,642**

Statement of Operations	**2010**	**2011**	**2012**	**2013**
Revenue	$ -	$ 89,468	$ 202,000	$ 280,000
Operating				
Labour	-	-	1,600	1,600
Management Fee	444	19,241	57,252	22,575
Interest Expense	57	5,855	28,551	50,744
Materials & Supplies	-	1,409	-	-
Business Equipment & Supplies	-	8,232	9,200	9,500
Professional Services	22,191	6,452	22,000	22,000
Property Tax and Insurance	-	8,022	33,000	33,000
Recoveries	-	-	(22,500)	(22,500)
Special Studies	-	2,700	5,000	5,000
	22,692	51,911	134,103	121,919
Amortization	-	31,821	118,000	215,800
Earning(Loss) before Int & Tax	**$ (22,692)**	**$ 5,736**	**$ (50,103)**	**$ (57,719)**

Note - There is no change to the above under MIFRS.

PURCHASE OF NON-AFFILIATE SERVICES

London Hydro Procurement Policy:

The London Hydro Procurement Policy is provided in Appendix 4K, as required by the Filing Requirements.

Signing Authority Levels:

London Hydro has a formal signing authority policy which is structured with various levels of approvals. This policy offers significant control on the procurement and payment of vendor invoices and is continually monitored by the Financial Services Department.

The following are the current signing authority levels under the policy:

Level (Postion)	Approval Limit ($)
Administrative Assistant	250
Supervisor/Manager	2,000
Director	5,000
Vice Presidents	10,000
Chief Financial Officer	15,000
Chief Executive Officer	50,000

Unique authorities are also utilized under the policy for large recurring items such as London Hydro Board approved contracts or purchases, power purchases from the IESO, Corporate Taxes, among others.

Competitive Tendering Process:

The following is an excerpt from London Hydro's Procurement Policy which describes the competitive tendering process at London Hydro. For more information related to the request for proposal ("RFP") process and the overall Procurement Policy, see Appendix 4K.

> A ***Tender*** is a request for suppliers to submit a formal sealed bid which contains a written offer made in a specified format for the supply of certain goods or services at a particular price to London Hydro.

Characteristics:

- Submitted in a formal sealed bid to the Executive Assistant to the Board of Directors
- Sent directly to the known suppliers of the product or service
- Always advertised in appropriate public media
- Always opened publicly
- Awarded on the basis of the lowest price meeting specifications as defined or described in the tender documents
- Results are reported to the Board of Directors after awarding of the contract by appropriate management authorities noted in 8.8
- Process is used for the acquisition of goods or services exceeding $50,000 (excluding engineered products and inventory replenishments).

London Hydro participates in buying consortiums for products and services. In these cases, the tendering process follows the consortium's policies. Some of these products and services include the following:

- Locator Services – Part of locator buying consortium
- Bulk Fuel – Part of Elgin-Middlesex-Oxford Public Purchasing Cooperative
- Servers – Part of Ontario Government Vendor of Record program

Historical Actual Purchased Services:

Table 4-48 and Table 4-49, on Page 106 provide a summary of the nature of the non-affiliate purchased service and a description of the methodology used in determining the vendor. The materiality threshold has been established as $294,000 for the 2011 historical year and $172,000 for the 2012 (year to date) details. See Exhibit 1, Table 1-23, on Page 69 for the calculation of this threshold. The 2012 activity covers a period up to July 31, 2012.

Table 4-48 - 2011 Non-Affiliate Purchased Services

2011 NON AFFILIATE PURCHASED SERVICES > Materiality Threshold ($294k)			
Name	Activity	Priced by	2011 Dollars
RAY Tech Solutions	Information Systems consulting	Tender T2011-N-3	1,756,241
Pachecos Contractors Ltd	Construction services	Tender T2010-N-21	1,716,888
Novinium	Cable injection	Tender T2010-N-4	1,301,055
D L Hannon Inc	Construction services	Tenders T2010-N-14, T2011-N-12	1,107,442
Olameter Inc	Meter reading services	Tender T2010-N-23	904,713
Intergraph Canada Ltd.	GIS software	Tender T2010-N-10	897,237
Infosys Technologies Limited	Information Systems consulting	Tenders T2010-N-13, T2011-N-3	747,577
Hydro One	Construction services	Sole Source	723,763
Itron Canada, Inc	Software consulting services	Proposal	560,715
ASEAL Roofing & Sheet Metal Lt	Roof replacement	Tender T2010-N-22	422,259
G-Tel Engineering	Locates	Joint locate tender (alliance)	389,138
Cameron Crane & Riggers	Crane services	Tender T2010-N-21	356,170
Southwest Power Corporation	Construction services	Tender T2010-N-21	342,169

Table 4-49 - 2012 Year to Date Non-Affiliate Purchased Services

2012 NON AFFILIATE PURCHASED SERVICES > Materiality Limit (Mid-Year $172k)			
Name	Activity	Priced by	2012 Dollars
Novinium	Cable injection	Tender T2010-N-4	631,727
Pachecos Contractors Ltd	Construction services	Tender T2010-N-21	619,369
Tata Consultancy Services Limi	Software maintenance	Tender T2011-N-3	602,563
RAY Tech Solutions	Information Systems consulting	Tender T2011-N-3	582,190
Olameter Inc	Meter reading services	Tender T2010-N-23	553,906
Capgemini Canada	Business consulting	Tender T2011-N-3	473,346
Itron Canada, Inc	Software consulting services	Proposal	345,295
G-Tel Engineering	Locates	Joint locate tender (alliance)	270,800
McCann Paving Inc	Construction services	Tender T2011-N-2	258,876
Langley Utilities Contracting	Construction services	Tender T2010-N-21	253,373
Infosys Technologies Limited	Information Systems consulting	Tender T2011-N-3	248,280
Intergraph Canada Ltd.	GIS enhancement services	Tender T2010-N-10	246,289
Benko Sewer Service	Construction services	Tender T2010-N-21	175,241

DEPRECIATION, AMORTIZATION, AND DEPLETION

Overview:

The following includes information that is related to depreciation, amortization, and depletion as required in the Board's Filing Requirements issued June 28, 2012. London Hydro intends on adopting IFRS as of January 1, 2013 for financial reporting purposes and will adopt new service lives based on both London Hydro's professional judgement and specific expertise related to its infrastructure and factors affecting the assets' useful lives and an independent study completed by Kinectrics for a small consortium of utilities including London Hydro.

Depreciation expense is provided by asset group for the Historical, Bridge, and Test Years and is presented under both CGAAP and MIFRS. Rounding of some totals has been completed for ease of presentation. All significant components of each item of Property, Plant & Equipment ("PP&E") are being depreciated separately for the 2012 Bridge and proposed 2013 Test Year under MIFRS using the most current estimates of useful service lives based on London Hydro's professional judgement and studies completed by Kinectrics for the OEB and by Kinectrics for a small consortium of utilities including London Hydro.

London Hydro seeks to recover approximately $15,906,200 of depreciation expense in the proposed 2013 Test Year under MIFRS. This total includes one year of amortization related to the CGAAP to MIFRS transition (1575) of approximately $118,000. The 2009 – 2011 Actual depreciation expense, the 2012 Bridge Year, and 2013 Test Year are provided in Table 4-50, Page 109. A comparison of London Hydro's useful service lives and the Kinectrics findings are in Table 4-52, Page 118. The full Kinectrics report is provided in Appendix D.

Depreciation related to non-distribution assets, specifically renewable generation, has been excluded for rate making purposes and is disclosed in the reconciliations between London Hydro's audited financial statements and the OEB Trial Balance as well as on the 2012 Bridge and 2013 Test Year Proforma Financial Statements. Separate Proforma Financial Statements and discussion related to the renewable generation activity is provided earlier in this Exhibit, in the Shared Cost, and Corporate Allocation section on Page 98.

Impacts to Depreciation Expense:

Since the last rebasing year (2009) four significant changes are impacting total depreciation expense:

- MIFRS;
- Transitional OEB 1575 Requirement;
- Smart Meter Depreciation; and
- Vehicle and Equipment Depreciation Accounting Change

Total depreciation expense fluctuates significantly between 2009 and 2013 due to the above events. Tables 4-53 and 4-54 on Pages 120 and 121 provide a breakdown of depreciation expense and year over year variances both before and after these impacts.

MIFRS and Transitional OEB 1575 Requirement:

Depreciation expense for the 2013 Test Year is based on the implementation of new useful service lives under MIFRS and also includes the amortization of the transitional impact (OEB - 1575) over a four year period.

In 2010, an independent consultant, Kinectrics, was engaged, to assist in an assessment of London Hydro's assets and review current estimated service lives. New services lives were developed based on internal London Hydro Engineering expertise related to the local infrastructure along with the Kinectrics Report developed for a small consortium of utilities. This formed the basis upon which depreciation expense is calculated. The Kinectrics Report is provided in Appendix 4D.

Table 4-50 - Amortization Expense - Impact of Smart Meters and MIFRS

DEPRECIATION EXPENSE - IMPACT of SMART METER AND MIFRS								
	CGAAP						MIFRS	
Description	2009 OEB Approved *(Note 1)*	2009 ACTUAL	2010 ACTUAL	2011 ACTUAL	2012 BRIDGE	2013 TEST	2012 BRIDGE	2013 TEST
Amortization Expense (before MIFRS & Smart Meter) *(Note 2)*	$15,437,100	15,077,495	15,950,097	16,859,795	$17,818,600	$18,431,000	$17,818,600	$18,431,000
Variance %			*5.8%*	*5.7%*	*5.7%*	*3.4%*		
Impact of:								
Transition (1575) Recovery	-	-	-	-	-	-	-	118,000
New Service Lives - PP&E	-	-	-	-	-	-	144,000	(4,876,000)
Incremental Smart Meter Amortization	-	-	-	-	2,193,400	2,233,200	2,193,400	2,233,200
TOTAL AMORTIZATION EXPENSE	**$15,437,100**	**$15,077,495**	**$15,950,097**	**$16,859,795**	**$20,012,000**	**$20,664,200**	**$20,156,000**	**$15,906,200**

Note 1 - 2009 OEB Approved Amortization of $15,919,000 adjusted by $481,900 for V&E depreciation. In 2010 an accounting change was made to include V&E depreciation in overhead rates allocated to operating and capital. Comparative figures are revised for comparability.

Note 2 - Bridge and Test Years are rounded to the nearest $100.

Table 4-51, Page 110 provides a summary of the useful service lives and amortization periods (in years) used in this application by asset category for both CGAAP and MIFRS presentations. Sub component useful service lives are listed in Tables 4-57 to 4-60, on Pages 126 to 129 (OEB required Depreciation Appendices 2-CE to 2-CH).

Smart Meter Depreciation:

In 2012 and 2013, depreciation related to the smart meters is now included in on-going depreciation expense. The smart meter depreciation in 2012 is being recovered via the Smart Meter Incremental Rate Rider ("SMIRR"), however, in 2013 it becomes part of the on-going amortization expense within Total Distribution Expense (before PILs).

Vehicle and Equipment Depreciation Accounting Change:

Subsequent to 2009 (the last rebasing year), an accounting change was made whereby vehicle and equipment depreciation, previously included in depreciation expense was allocated to operating and capital activities via an hourly overhead rate. The 2009 Board approved depreciation expense of $15,919,000 included vehicle and equipment depreciation of $481,900 and therefore it has been restated to $15,437,100 for comparative purposes. Historical Actuals, 2012 Bridge, and 2013 Test Years all exclude vehicle and equipment depreciation expense.

Table 4-51 - Useful Service Lives Summary

Summary of Rate of Depreciation/Amortization (in years)

		CGAAP 2009 - 2013	MIFRS 2012 - 2013
		(years)	
1805	Land	n/a	n/a
1806	Land Rights	15-25	25
1808	Buildings (Substations)	25-50	30-75
1820	Equipment (Substations)	30	15-45
1610	Intangible Wholesale Meters	30	30
1830	Poles, Towers & Fixtures	25	45
1835	OH Conductors & Devices	15-25	45-50
1840	UG Conduit	25	30-60
1845	UG Conductors & Devices	25-40	26.5-30
1850	Transformers	15-35	35
1855	Services	25	30-60
1860	Electric Meters	15-35	15-30
1908	Buildings (General Plant Area)	25-55	12-65
1915	General Office	10	5
1920	Computer Equipment - Hardware	5	3
1925	Computer Equipment - Software	5	3-5
1930	Transportation	5-10	8-12
1935	Stores Department	10	8
1940	Tools, Shop, Garage Equipment	10	8
1945	Meter Department	10	8
1950	Power Operated (Major) Equipment	8	8
1955	Communication Equipment	15-35	15-35
1960	Miscellaneous	10	10
1980	System Supervisory Equip (Scada)	15	10-20
1995	Contributed Capital	25	40

Note 1 - London Hydro has adopted the Board's general policy for electricity distribution rate setting and used the 1/2 year rule when calculating depreciation in the year of addition

Depreciation/Amortization Policy:

Historical (CGAAP 2009 – 2012):

Although London Hydro did not have a formalized depreciation/amortization policy, it can confirm that historically, under CGAAP, it has complied with both the OEB's APH and the CICA Handbook, with respect to the amortization of capital assets. There has been no change in the standard amortization rates used over the years being reviewed in this Exhibit under the historical accounting standard (CGAAP). The amortization rates used by London Hydro were in accordance with the rates set out in the OEB's *2006 Electricity Distribution Rate Handbook*, and are provided in Table 4-51, Page 110 with only minor exceptions due to mandated changes effective January 1, 1986 by the previous regulator, Ontario Hydro. Assets affected were acquired prior to this change and continued to be amortized at the rate prescribed at the time of acquisition.

Bridge and Test Year (MIFRS 2012 – 2013):

In preparation for the adoption of International Financial Reporting Standards ("IFRS"), London Hydro completed a formal capitalization policy reflecting the new requirements under that accounting standard. Although London Hydro opted to defer the transition to IFRS until January 1, 2013, this policy is used as the basis under which amortization is calculated for the 2012 Bridge and proposed 2013 Test Years.

Both the MIFRS 2012 Bridge and proposed 2013 Test Years depreciation forecasts are based on the new useful service lives, and, are calculated in a rational and systematic manner as required as follows:

- Using a straight line basis over the estimated remaining useful life of the assets;
- Half-Year rule is applied in year of addition; and
- Spare transformers and electric meters are accounted for as property, plant and equipment assets and subject to amortization from the date of acquisition

London Hydro has applied both professional judgment and an independent review of the local infrastructure and incorporated factors such as technical or commercial obsolescence, expected usage, expected physical wear and tear, and maintenance programs, among others in determining asset service lives in accordance with International Accounting Standard ("IAS") 16.

The net book value of the asset as at January 1, 2012 is the basis of the depreciation calculation. The calculated average remaining service life is applied to the net book value after the removal of fully depreciated assets from the preceding year.

The capitalization policy referred to in the above discussion is included in Exhibit 10, Appendix 10B.

"Half-Year" Rule:

London Hydro can confirm that it has complied with the Board's general policy for electricity distribution rate setting under which capital additions would attract six months of depreciation expense when they are put into service. Both the forecast for the 2012 Bridge and the proposed 2013 Test Years are developed this way. Tables 4-57 to 4-60, on Pages 125 to 128 can be referenced as supporting evidence in this regard. Historical actual depreciation expense is calculated automatically using London Hydro's fixed asset system. Actual additions to capital assets are updated on a quarterly basis, as assets are put into service.

Kinectrics Study and the London Hydro Useful Service Lives:

Overview:

As previously discussed, London Hydro engaged Kinectrics to conduct a study for a small consortium of utilities to assist in making changes to the existing service lives utilized in the calculation of depreciation expense. This report was completed in January 2010. As well, the OEB sponsored a Kinectrics study which was completed in July 2010. Table 4-52, Page 118 provides a comparison of the two Kinectrics studies with section references as well as the established London Hydro useful service lives. In some cases there are significant differences between the two Kinectrics studies which illustrate that useful service lives can vary among LDCs.

Not all asset components were included in the study completed for the London Hydro consortium, and therefore the comparisons of these components will use the Kinectrics report completed for the OEB. This section of the Kinectrics report *(Table F – 2)* established useful life ranges based on the experience of the Ontario LDCs interviewed, and no further analysis of these assets was considered necessary.

In order to comply with IFRS requirements, London Hydro utilized information from the aforementioned studies, and incorporated professional judgment and expertise related to its specific environment and operating and maintenance programs when formulating useful service lives. The results differ slightly from both the Kinectrics reports' Typical Useful Lives ("TUL"), however are generally, within a relatively close range.

Within *Section 1.4.4* of the study prepared for London Hydro, "Typical Life" is described as:

> *"…the typical age that an asset or component fails. This may vary depending on a utility's maintenance practices, environmental conditions, and operational stresses".*

The study also states it incorporates typical time based maintenance intervals in *Section 1.4.5* of the study and concludes that:

> *"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".*

Both of these statements support the fact that the TUL can vary from one utility to another. London Hydro believes that its in-depth review of each asset component resulted in the establishment of the most appropriate service lives for its current environment. As required under IFRS, London Hydro will conduct annual reviews and update service lives accordingly in the future.

London Hydro has an established Asset Sustainment Plan (Exhibit 2, Appendix 2C) that forecasts replacement requirements from a long term perspective. This plan reviews the optimal timeframes for replacement with the goal of replacing certain assets before failure to ensure continued reliability of the system. The established useful lives are also supported by this Plan.

Impact of New Useful Service Lives:

The implementation of new service lives under MIFRS has resulted in a reduction of Amortization Expense in the amount of $4,876,000 for the proposed 2013 Test Year.

Variances to Typical Useful Life:

The following commentary is provided to support variances in TUL as required in Section 2.7.7 of the Board's Filing Requirements:

1805 - Substation Building (Overall)

London Hydro has chosen a useful life of 75 years for this asset component.

The Kinectrics report completed for the OEB did not provide a Typical Useful Live (“TUL”), however provided a range of 50 to 75 years. The Kinectrics report completed for London Hydro provided a TUL of 50 years and a full range of 30 to 80 years.

The condition of the substation buildings and the construction methods that were used when they were built indicate that the useful service life should be estimated at the high end of the range and that the TUL is not appropriate. There is the possibility that changes to system plans could eliminate the need for some substation buildings and this may have an impact on service life; therefore, the maximum years in the range was not chosen

1805 - Substation Roof

London Hydro has chosen a useful life of 30 years for this asset component.

The Kinectrics report completed for the OEB did not provide a Typical Useful Live (“TUL”), however provided a range of 20 to 30 years. The Kinectrics report completed for London Hydro provided a TUL of 20 years and a full range of 15 to 30 years.

London Hydro is establishing the useful life based on actual experience and the grade of roofing material used during replacement projects.

1835 - Primary Conductor

London Hydro has chosen a useful life of 50 years for this asset component.

The Kinectrics report completed for the OEB and for London Hydro provided for a TUL of 60 years in both studies and an overall range of 50 to 77 years, and 50 to 75 years respectively.

Generally, when a pole line is rebuilt it is London Hydro’s practice to replace the primary conductor at the same time as the poles. Therefore the TUL used is just slightly higher than the TUL used for poles as in some cases, the conductor may be transferred to new poles and not replaced.

1845 - PILC Primary Cable

London Hydro has chosen a useful life of 30 years for this asset component.

The Kinectrics report completed for the OEB and for London Hydro provided for a TUL of 65 and 75 years and an overall range of 70 to 80 years, and 60 to 75 years respectively.

This cable is sheathed in lead which is considered a "designated substance". It is London Hydro's strategy to eliminate lead products from the workplace and not reuse this type of cable. Current plans are to replace this cable over a period of time significantly lower than the TUL.

1850 - Line Transformers (Pad Mount and Overhead Transformers)

London Hydro has chosen a useful life of 35 years for these asset components.

The Kinectrics report completed for the OEB and for London Hydro provided for a TUL of 40 years in both studies and an overall range of 25 to 60 years, and 20 to 60 years respectively.

It is London Hydro's replacement practice to not return pad mount and overhead transformers back into service if the unit was built prior to 1989. This was the year London Hydro began specifying lower loss transformers and this practice is used to conserve energy and minimize system losses. Also, certain styles of older transformers (no external tap changer or non-switchable, for example) are also not reused when they come in from the field. This results in a lower average life than the TUL.

1860 - Metering CT's and PT's

London Hydro has chosen a useful life of 30 years for these asset components.

The Kinectrics report completed for the OEB did not provide a Typical Useful Live ("TUL"), however provided a range of 35 to 50 years. The Kinectrics report completed for London Hydro provided a TUL of 45 years and a full range of 30 to 50 years.

Metering CT's and PT's are used exclusively for commercial locations and the useful life is impacted by the customer profile, requirements, and demand. It is London Hydro's experience that the useful life of these components is significantly lower than the TUL reported by Kinectrics and therefore is estimated at the minimum of the range.

1905 - Buildings and Fixtures (Parking)

London Hydro has chosen a useful life of 30 years for this asset component.

The Kinectrics report completed for the OEB did not provide any information related to a Typical Useful Live ("TUL") for this component however provided a range of 25 to 30 years for this sub-component of Buildings and Fixtures (Distribution - Substations). The Kinectrics report completed for London Hydro provided a TUL of 20 years and a full range of 15 to 30 years.

It has been London Hydro's experience that the TUL provided in the Kinectrics report is low. Parking lot replacements have typically occurred at 30 years.

1905 - Buildings and Fixtures (Fences)

London Hydro has chosen a useful life of 60 years for this asset component.

The Kinectrics report completed for the OEB did not provide any information related to a Typical Useful Live ("TUL") for this component however provided a range of 25 to 60 years for this sub-component of Buildings and Fixtures (Distribution - Substations). The Kinectrics report completed for London Hydro provided a TUL of 35 years and a full range of 30 to 60 years. Significant variances exist between the ranges in these two reports.

It has been London Hydro's experience that the TUL provided by Kinectrics is low. Fencing on utility property, installed in the 1960's is still not requiring replacement.

1905 - Buildings and Fixtures (Electronic/Mechanical Systems)

London Hydro has chosen a useful life of 12 years for this asset component.

The Kinectrics report completed for the OEB did not provide any information for this sub-component. The Kinectrics report completed for London Hydro provided a TUL of 20 years and a full range of 12 to 30 years.

Electronic systems are subject to technology changes, and therefore the low end of the range has been chosen as it London Hydro's professional judgement and experience that replacement will likely be required between 10 and 15 years.

1955 - Communication Equipment (Towers)

London Hydro has chosen a useful life of 35 years for this asset component.

The Kinectrics report completed for the OEB did not provide a Typical Useful Live ("TUL"), however provided a range of 60 to 70 years. The Kinectrics report completed for London Hydro provided a TUL of 63 years and a full range of 35 to 100 years. Significant variances exist between the ranges in these two reports.

Although London Hydro concurs with the TUL and overall possible ranges related to the service life of communication towers, it is believed that foreseeable changes in technology will affect these assets significantly. With the movement to a smart grid system, current wireless technology will surely change and may even become obsolete, impacting the towers' usefulness.

Other Components

The useful service lives for components not reviewed as part of the scope of the Kinectrics study for the London Hydro consortium such as office furniture and equipment, computer hardware and software, transportation and power operated equipment, among others, are all established within the range reported by Kinectrics to the OEB.

Other components such as Distribution Equipment (Digital Relays), Poles, Towers and Fixtures, Underground Conduit and Devices (Air Insulated Switchgear and Vault and Manhole Roofs) differ slightly from the Kinectrics study for the London Hydro consortium as London Hydro has experienced fewer issues than the TUL indicates. In these cases, the established TUL is longer than the reported TUL.

Other variances exist, however, are considered immaterial. London Hydro has applied professional judgement and expertise in establishing all the new estimated useful lives as it prepared for the adoption of IFRS and this Application.

Table 4-52 - Comparison of London Hydro and Kinectrics Studies

(Useful Lives by Asset Component)

			London Hydro ("LH") Life Span		Kinectrics for LH Life span				Kinectrics for OEB (Jul 2010) Life span			
OEB	Asset Category	Component	(CGAAP)	(IFRS)	Min.	Typical	Max.	Reference	Min.	Typical	Max.	Reference
1800	Land	Land	n/a	n/a	n/a	n/a	n/a		n/a	n/a	n/a	
1806	Land Rights	Land Rights (Easements)	15-25	25	-	-	-		-	-	-	
1808	Buildings & Fixtures (Distribution)	Substation Building	25-50	75	30	50	80	16	50	-	75	F-2,5
		Substation Roof	25-50	30	15	20	30	16	20	-	30	F-2,5
1820	Distribution Equipment <50kV	Substation Equipment	30	45	20-40	30-60	50-100	12-14	10-35	20-50	30-90	12-14,22&23
		Battery Banks & Chargers	30	15	10-20	15-20	15-30	15	10-30	15-20	15-30	15
		Digital Relays	30	20	10	15	25	14	15	20	20	21
		Intangible -w holesale mtr	30	30	20	30	60	29	15	-	30	F-2,11
1830	Poles, Tow ers & Fixtures	Poles, Tow ers & Fixtures	25	45	40	44	80	2	35	45	75	1
1835	OH Conductor & Devices	OH Primary Conductor	15-25	50	50	60	77	10	50	60	75	8
		Sw itches & Reclosers	15-25	45	15-30	20-50	20-60	7-8	15-35	25-45	25-60	4,5 & 7
1840	Underground Conduit	Vaults & Manholes	25-40	60	50	60	80	23,24&26	40	60	80	37
		Vault & Manhole Roofs	25-40	30	20	25	40	23,24	20	30	45	37
1845	UG Conductor & Devices	TR-XB-TRXLPE Cable-Primary (direct buried)	25-40	26.5	20	25	40	21	25	30	35	28
		TR-XB-TRXLPE Cable-Primary (in duct)	25-40	26.5	40	40	60	21	35	40	55	29
		SF6 & Vacuum Sw itchgear	25	30	30	30	50	25	20	30	45	39
		PILC Primary Cable	25-40	30	70	75	80	21	60	65	75	24
		Air Insulated Sw itchgear	25	25	20	20	40	25	20	30	45	39
1850	Line Transformers	Pad Mount Transformers	15-30	35	30	40	40	18	25	40	45	34
		Netw ork Transformers	15-30	35	20	35	40-50	19	20	35	40-50	33
		Overhead Transformers	15-30	35	30	40	60	17	30	40	60	9
1855	Services	UG Secondary Services (direct buried)	25	30	20	25	25	22	25	35	40	31
		UG Secondary Services (in duct)	25	30	40	40	60	22	35	40	60	32
		OH Secondary Services	25	60	50	60	77	10	50	60	75	8
1860	Meters	Regular Meters	15-35	30	20	30	45	29	25	-	35	F-2,9
		Smart Meters	15	15	15	15	20	30	5	-	15	F-2,13
		Metering CT's & PT's	15-35	30	30	45	50	29	35	-	50	F-2,12
1908	Buildings and Fixtures	Buildings - Civil	25-55	65	30	50-60	100	32	50	-	75	F-2,3
		Buildings - Roof	25-55	25	15	20	30	32	-	-	-	
		Building - Parking	25-55	30	15	20	30	32	-	-	-	
		Building - Fences	55	60	30	35	60	32	-	-	-	
		Electronic/Mechanical Systems	25	12	12	20	30	32	-	-	-	
		Electric / Mechanical Systems	25-55	30	12	20	40	32	-	-	-	
1915	Office Furniture and Equipment	Office Furniture and Equipment	10	5	-	-	-		5	-	15	F-2,1
1920	Computer Equipment - Hardw are	Computer Equipment - Hardw are	5	3	-	-	-		3	-	5	F-2,6
1925	Computer Equipment - Softw are	Major Applications	5	5	-	-	-		2	-	5	F-2,6
		Minor Application	5	3	-	-	-		2	-	5	F-2,6
1930	Transportation - Cars/Vans	Transportation - Cars/Vans	5	8	-	-	-		5	-	10	F-2,2
	Transportation - Major Vehicles	Transportation - Major Vehicles	8	12	-	-	-		5	-	15	F-2,2
	Trailers	Trailers	10	10	-	-	-		5	-	20	F-2,2
1935	Stores Equipment	Stores Equipment	10	8	-	-	-		5	-	10	F-2,7
1940	Tools, Shop, and Garage Equipment	Tools, Shop, and Garage Equipment	10	8	-	-	-		5	-	10	F-2,7
1945	Measurement and Test Equipment	Measurement and Test Equipment	10	8	-	-	-		5	-	10	F-2,7
1950	Pow er Operated Equipment	Pow er Operated Equipment	8	8	-	-	-		5	-	10	F-2,7
1955	Communication Equipment	Communication Tow ers	35	35	35	63	100	30	60	-	70	F-2,8
		Communication - Wireless	15	15	5-10	10-20	15-20	30	2	-	10	F-2,8
1980	System Supervisory Equipment	Scada RTU's	15	20	15	20	30	31	15	20	20	6
		Scada Master Station	15	10	-	-	-		15	20	30	43
1995	Contribution & Grants Credit	Contribution & Grants Credit	25	40	-	-	-		-	-	-	

Asset Retirement Obligations ("AROs"):

London Hydro does not have any Asset Retirement Obligations ("AROs") or associated depreciation or accretion expenses in relation to the AROs to report as part of this application.

Depreciation Expense by Asset Group with Variances:

A summary of London Hydro's depreciation expense by asset group and variances for the 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, 2012 Bridge Year and the proposed 2013 Test Year is provided in Tables 4-53 and 4-54, Pages 120 and 121. Depreciation expense has been reconciled to the fixed asset continuity schedules provided in Exhibit 2, Appendix 2A and is presented under both CGAAP and MIFRS standards.

Significant year over year variances in depreciation expense by asset group fall into 4 main categories

1. Due to MIFRS in 2013
2. Due to Smart Meter Transfer from deferral account to capital assets in 2012
3. Due to Continued investment in Information Technology (hardware and software) with relatively short useful lives
4. Due to Continued investment in Transportation and Power Operated Equipment with relatively short useful lives

A full discussion related to the impacts of MIFRS and Smart Meters to depreciation expense has been provided in the preceding sections, Pages 108 to 109.

Depreciation expense and variances year on year is related to the Asset Management and IT Strategy Plans. Refer to Exhibit 2, Appendix 2B and 2I for justification of the purchase of these assets.

Table 4-53 - Depreciation Expense Summary (2009 – 2013)

DEPRECIATION EXPENSE 2009 TO 2013 - Summary

		CGAAP						MIFRS	
		2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	2012 Bridge	2013 Test
Distribution Plant		$12,682,263	$12,551,867	$12,913,574	$13,358,466	$14,787,001	$15,129,689	$12,017,120	$ 9,236,143
General Plant		1,241,662	1,298,428	1,581,484	1,861,043	2,243,951	2,475,708	3,726,277	2,229,412
Information Systems		2,943,875	2,654,670	2,899,697	3,247,830	4,832,590	5,626,003	5,314,117	5,867,596
Total Additions before Contributed Capital		**16,867,800**	**16,504,965**	**17,394,755**	**18,467,339**	**21,863,542**	**23,231,400**	**21,057,514**	**17,333,151**
1995 Contributions and Grants		(948,800)	(969,197)	(1,082,475)	(1,204,147)	(1,362,714)	(1,439,575)	(769,587)	(817,624)
		$15,919,000	**$15,535,769**	**$16,312,280**	**$17,263,192**	**$20,500,828**	**$21,791,825**	**$20,287,927**	**$16,515,527**
Add: Depreciation on Stranded Meters	*Note 1*	-	-	191,248	374,333	437,000	-	437,000	-
Add: Amortization of 1575 MIFRS Transition	*Note 2*	-	-	-	-	-	-	-	118,000
Less: V&E (included in OH Allocation)	*Note 3*	(481,967)	(458,274)	(553,431)	(777,730)	(926,101)	(1,127,578)	(568,923)	(726,773)
Rounding		67	-	-	-	273	(47)	(4)	(554)
		$15,437,100	**$15,077,495**	**$15,950,097**	**$16,859,795**	**$20,012,000**	**$20,664,200**	**$20,156,000**	**$15,906,200**

Note 1 - Continue to amortize stranded meters until rebasing in 2013. Offset to regulatory asset (stranded meters) for future recovery through SMDRR. Not recorded on FA continuity schedule and explains difference between these schedules

Note 2 - Amortization of 1575 over 4 years begins in 2013. This is offset to regulatory asset and not recorded on FA continuity schedule, and explains the difference between these schedules

Note 3 - V&E depreciation is included in overhead allocation and is therefore excluded from depreciation expense. The 2009 OEB approved, and 2009 Actuals are restated for comparibility to future years due to an accounting change in 2010. Previously, the V&E depreciation was not included in the overhead rate, and in 2010 this was changed and the overhead rate has included V&E depreciation and allocated to operating, and capital activities.

1 **Table 4-54 - Depreciation Variances Summary (2009 – 2013)**

ANNUAL CHANGE IN DEPRECIATION EXPENSE 2009 TO 2013 - Summary																
	CGAAP (Year to Year Change)												MIFRS (Incremental Change)			
	2009 OEB Approved to 2009 Actual		2009-2008 Actual		2010-2009 Actual		2011-2010 Actual		2012 Bridge-2011 Actual		2013 Test - 2012 Bridge		2012 Bridge MIFRS - 2012 Bridge CGAAP		2013 Test MIFRS - 2013 Test CGAAP	
Distribution Plant	$(130,396)	*-1.03%*	$ 730,998	*6.18%*	$ 361,707	*2.88%*	$ 444,892	*3.45%*	$1,428,535	*10.69%*	$ 342,688	*2.32%*	$(2,769,881)	*-18.73%*	$(5,893,546)	*-38.95%*
General Plant	56,766	*4.57%*	163,948	*14.45%*	283,056	*21.80%*	279,559	*17.68%*	382,908	*20.57%*	231,757	*10.33%*	1,482,326	*66.06%*	(246,296)	*-9.95%*
Information Systems	(289,205)	*-9.82%*	(888,482)	*-25.08%*	245,027	*9.23%*	348,133	*12.01%*	1,584,760	*48.79%*	793,413	*16.42%*	481,527	*9.96%*	241,593	*4.29%*
Total Additions before Contributed Capital	(362,835)	*-2.15%*	6,464	*0.04%*	889,790	*5.39%*	1,072,584	*6.17%*	3,396,203	*18.39%*	1,367,858	*6.26%*	(806,028)	*-3.69%*	(5,898,249)	*-25.39%*
1995 Contributions and Grants	(20,397)	*2.15%*	(165,479)	*20.59%*	(113,279)	*11.69%*	(121,672)	*11.24%*	(158,567)	*13.97%*	(76,861)	*5.64%*	593,127	*-43.53%*	621,951	*-43.20%*
	$(383,231)	***-2.41%***	**$(159,016)**	***-1.01%***	**$ 776,511**	***5.00%***	**$ 950,912**	***5.83%***	**$3,237,636**	***18.75%***	**$1,290,997**	***6.30%***	**$ (212,901)**	***-1.04%***	**$(5,276,298)**	***-24.21%***

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Table 4-55 - Depreciation Expense by Asset Group

DEPRECIATION EXPENSE 2009 TO 2013									
		CGAAP						MIFRS	
(Note 4)		2009 OEB Approved	2009 Actual	2010 Actual	2011 Actual	2012 Bridge	2013 Test	2012 Bridge	2013 Test
Distribution Plant									
1806 / 1612 Land Rights		$ 40,021	$ 15,135	$ 13,120	$ 13,036	$ 11,835	$ 11,835	$ 15,009	$ 15,009
1808 Buildings - Substations		165,433	155,861	27,872	27,885	29,807	32,807	17,772	12,592
1820 /1610 Substation Equipment		287,785	319,966	326,362	379,582	443,811	446,325	325,470	310,562
1830 Poles, Towers & Fixtures		460,224	524,906	1,394,771	1,451,539	1,505,461	1,563,993	540,059	594,985
1835 OH Conductors & Devices		3,062,195	2,956,663	1,937,974	2,061,140	2,157,692	2,265,896	753,640	822,496
1840 UG Conduit		748,548	847,727	1,075,869	1,155,185	1,276,038	1,358,697	476,478	503,296
1845 UG Conductor & Devices		4,320,308	4,053,966	4,102,582	4,153,383	4,171,527	4,172,634	6,451,975	3,383,304
1850 Line Transformers		2,500,000	2,577,827	2,800,945	2,892,693	2,932,035	2,960,818	1,640,882	1,786,062
1855 Services (OH & UG)		332,970	387,660	691,255	752,727	815,144	850,879	391,970	423,138
1860 Meters		764,779	712,157	542,824	471,296	1,443,651	1,465,805	1,403,865	1,384,699
		12,682,263	12,551,867	12,913,574	13,358,466	14,787,001	15,129,689	12,017,120	9,236,143
General Plant									
1908 Buildings & Fixtures		340,201	396,432	560,820	608,055	638,895	659,104	1,874,530	832,892
1915 Office Furniture & Equipment		97,281	106,191	113,228	103,162	102,684	107,425	331,112	156,331
1930 Transportation Equipment		445,267	421,197	508,277	701,306	825,063	1,014,978	467,744	614,032
1935 Stores Equipment		29,397	29,448	29,586	29,290	9,446	5,346	12,239	8,118
1940 Tools, Shop & Garage Equipment		98,318	106,306	114,242	114,769	112,247	118,560	184,383	139,334
1945 Measurement & Testing Equipment		10,524	10,545	10,483	6,847	9,036	14,432	13,593	14,809
1950 Power Operated Equipment		36,700	37,077	45,154	76,424	101,038	112,600	101,179	112,741
1955 Communication Equipment		-	-	-	340	225,895	230,800	225,893	230,598
1960 Miscellaneous Equipment		-	-	-	-	-	-	-	
1980 System Supervisory Equipment		183,974	191,232	199,693	220,850	219,647	212,463	515,604	120,557
		1,241,662	1,298,428	1,581,484	1,861,043	2,243,951	2,475,708	3,726,277	2,229,412
Information Systems									
1920 Computer - Hardware		722,319	602,562	481,514	380,552	433,722	417,261	728,776	510,931
1925 /1611 Computer - Software		2,221,556	2,052,108	2,418,182	2,867,278	4,398,868	5,208,742	4,585,341	5,356,665
		2,943,875	2,654,670	2,899,697	3,247,830	4,832,590	5,626,003	5,314,117	5,867,596
Total Additions before Contributed Capital		**16,867,800**	**16,504,965**	**17,394,755**	**18,467,339**	**21,863,542**	**23,231,400**	**21,057,514**	**17,333,151**
1995 Contributions and Grants		(948,800)	(969,197)	(1,082,475)	(1,204,147)	(1,362,714)	(1,439,575)	(769,587)	(817,624)
		$15,919,000	**$15,535,769**	**$16,312,280**	**$17,263,192**	**$20,500,828**	**$21,791,825**	**$20,287,927**	**$16,515,527**
Add: Depreciation on Stranded Meters	*(Note 1)*	-	-	191,248	374,333	437,000	-	437,000	-
Add: Amortization of 1575 MIFRS Transition	*(Note 2)*								118,000
Less: V&E (included in OH Allocation	*(Note 3)*	(481,967)	(458,274)	(553,431)	(777,730)	(926,101)	(1,127,578)	(568,923)	(726,773)
Rounding		67	-	-		273	(47)	(4)	(554)
		$15,437,100	**$15,077,495**	**$15,950,097**	**$16,859,795**	**$20,012,000**	**$20,664,200**	**$20,156,000**	**$15,906,200**

Note 1,2,3 - See Table ##, Page ##
Note 4 - OEB objects for some assets groups will change under MIFRS. Where necessary both OEB objects are showing. Note that in some cases the new object only pertains to a portion of the previous object account.

Table 4-56 - Annual Variances in Depreciation by Asset Group

ANNUAL CHANGE IN DEPRECIATION EXPENSE 2009 TO 2013																
	CGAAP (Year to Year Change)												MIFRS (Incremental Change)			
	2009 OEB Approved to 2009 Actual		2009-2008 Actual		2010-2009 Actual		2011-2010 Actual		2012 Bridge-2011 Actual		2013 Test - 2012 Bridge		2012 Bridge MIFRS - 2012 Bridge CGAAP		2013 Test MIFRS - 2013 Test CGAAP	
Distribution Plant																
1806 Land Rights	$ (24,886)	*-62.18%*	$ (24,663)	*-62.0%*	$ (2,015)	*-13.3%*	$ (84)	*-0.6%*	$ (1,201)	*-9.2%*	$ -	*0.0%*	$ 3,174	*26.8%*	$ 3,174	*26.8%*
1808 Buildings - Substations	(9,572)	*-5.79%*	4,025	*2.7%*	(127,989)	*-82.1%*	13	*0.0%*	1,922	*6.9%*	3,000	*10.1%*	(12,035)	*-40.4%*	(20,215)	*-61.6%*
1820 Substation Equipment	32,181	*11.18%*	32,514	*11.3%*	6,397	*2.0%*	53,220	*16.3%*	64,229	*16.9%*	2,514	*0.6%*	(118,341)	*-26.7%*	(135,763)	*-30.4%*
1830 Poles, Towers & Fixtures	64,682	*14.05%*	75,514	*16.8%*	869,865	*165.7%*	56,768	*4.1%*	53,922	*3.7%*	58,532	*3.9%*	(965,402)	*-64.1%*	(969,008)	*-62.0%*
1835 OH Conductors & Devices	(105,532)	*-3.45%*	69,991	*2.4%*	(1,018,689)	*-34.5%*	123,166	*6.4%*	96,552	*4.7%*	108,204	*5.0%*	(1,404,052)	*-65.1%*	(1,443,400)	*-63.7%*
1840 UG Conduit	99,179	*13.25%*	147,692	*21.1%*	228,143	*26.9%*	79,316	*7.4%*	120,853	*10.5%*	82,659	*6.5%*	(799,560)	*-62.7%*	(855,401)	*-63.0%*
1845 UG Conductor & Devices	(266,342)	*-6.16%*	145,112	*3.7%*	48,616	*1.2%*	50,801	*1.2%*	18,144	*0.4%*	1,107	*0.0%*	2,280,448	*54.7%*	(789,330)	*-18.9%*
1850 Line Transformers	77,827	*3.11%*	201,689	*8.5%*	223,118	*8.7%*	91,748	*3.3%*	39,342	*1.4%*	28,783	*1.0%*	(1,291,153)	*-44.0%*	(1,174,756)	*-39.7%*
1855 Services (OH & UG)	54,690	*16.43%*	62,128	*19.1%*	303,595	*78.3%*	61,472	*8.9%*	62,417	*8.3%*	35,735	*4.4%*	(423,174)	*-51.9%*	(427,741)	*-50.3%*
1860 Meters	(52,622)	*-6.88%*	16,996	*2.4%*	(169,333)	*-23.8%*	(71,528)	*-13.2%*	972,355	*206.3%*	22,154	*1.5%*	(39,786)	*-2.8%*	(81,106)	*-5.5%*
	(130,396)	*-1.03%*	730,998	*6.2%*	361,707	*2.9%*	444,892	*3.4%*	1,428,535	*10.7%*	342,688	*2.3%*	(2,769,881)	*-18.7%*	(5,893,546)	*-39.0%*
General Plant																
1908 Buildings & Fixtures	56,231	*16.53%*	72,281	*22.3%*	164,389	*41.5%*	47,235	*8.4%*	30,840	*5.1%*	20,209	*3.2%*	1,235,635	*193.4%*	173,788	*26.4%*
1915 Office Furniture & Equipment	8,910	*9.16%*	11,388	*12.0%*	7,037	*6.6%*	(10,066)	*-8.9%*	(478)	*-0.5%*	4,741	*4.6%*	228,428	*222.5%*	48,906	*45.5%*
1930 Transportation Equipment	(24,070)	*-5.41%*	145,318	*52.7%*	87,080	*20.7%*	193,029	*38.0%*	123,757	*17.6%*	189,915	*23.0%*	(357,319)	*-43.3%*	(400,946)	*-39.5%*
1935 Stores Equipment	51	*0.18%*	(5,320)	*-15.3%*	138	*0.5%*	(296)	*-1.0%*	(19,844)	*-67.8%*	(4,100)	*-43.4%*	2,793	*29.6%*	2,772	*51.9%*
1940 Tools, Shop & Garage Equipment	7,988	*8.12%*	12,679	*13.5%*	7,935	*7.5%*	527	*0.5%*	(2,522)	*-2.2%*	6,313	*5.6%*	72,136	*64.3%*	20,774	*17.5%*
1945 Measurement & Testing Equipment	21	*0.20%*	(19,494)	*-64.9%*	(61)	*-0.6%*	(3,636)	*-34.7%*	2,189	*32.0%*	5,396	*59.7%*	4,557	*50.4%*	377	*2.6%*
1950 Power Operated Equipment	377	*1.03%*	11,279	*43.7%*	8,077	*21.8%*	31,270	*69.3%*	24,614	*32.2%*	11,562	*11.4%*	141	*0.1%*	141	*0.1%*
1955 Communication Equipment	-	-	-	*0.0%*	-	*0.0%*	340	*0.0%*	225,555	*66339.7%*	4,905	*2.2%*	(2)	*0.0%*	(202)	*-0.1%*
1960 Miscellaneous Equipment	-	-	-	*0.0%*	-	*0.0%*	-	*0.0%*	-	*0.0%*	-	*0.0%*	-	*0.0%*	-	*0.0%*
1980 System Supervisory Equipment	7,258	*3.95%*	(64,183)	*-25.1%*	8,461	*4.4%*	21,157	*10.6%*	(1,203)	*-0.5%*	(7,184)	*-3.3%*	295,957	*134.7%*	(91,906)	*-43.3%*
	56,766	*4.57%*	163,948	*14.5%*	283,056	*21.8%*	279,559	*17.7%*	382,908	*20.6%*	231,757	*10.3%*	1,482,326	*66.1%*	(246,296)	*-9.9%*
Information Systems																
1920 Computer - Hardware	(119,757)	*-16.58%*	(106,404)	*-15.0%*	(121,048)	*-20.1%*	(100,962)	*-21.0%*	53,170	*14.0%*	(16,461)	*-3.8%*	295,054	*68.0%*	93,670	*22.4%*
1925 Computer - Software	(169,448)	*-7.63%*	(782,078)	*-27.6%*	366,074	*17.8%*	449,096	*18.6%*	1,531,590	*53.4%*	809,874	*18.4%*	186,473	*4.2%*	147,923	*2.8%*
	(289,205)	*-9.82%*	(888,482)	*-25.1%*	245,027	*9.2%*	348,133	*12.0%*	1,584,760	*48.8%*	793,413	*16.4%*	481,527	*10.0%*	241,593	*4.3%*
Total Additions before Contributed Capital	(362,835)	*-2.15%*	6,464	*0.0%*	889,790	*5.4%*	1,072,584	*6.2%*	3,396,203	*18.4%*	1,367,858	*6.3%*	(806,028)	*-3.7%*	(5,898,249)	*-25.4%*
1995 Contributions and Grants	(20,397)	*2.15%*	(165,479)	*20.6%*	(113,279)	*11.7%*	(121,672)	*11.2%*	(158,567)	*14.0%*	(76,861)	*5.6%*	593,127	*-43.5%*	621,951	*-43.2%*
	$(383,231)	***-2.41%***	**$(159,016)**	***-1.0%***	**$ 776,511**	***5.0%***	**$ 950,912**	***5.8%***	**$3,237,636**	***18.8%***	**$1,290,997**	***6.3%***	**$ (212,901)**	***-1.0%***	**$(5,276,298)**	***-24.2%***

Gross Asset Amounts by Asset Group:

See Exhibit 2, Table 2-6, on Page 8 for annual asset amounts by Asset Group.

Depreciation Tables (OEB 2-CE to 2-CH):

London Hydro has chosen to adopt IFRS for financial reporting in 2013, and has provided the following appendices in compliance with the Filing Requirements.

There are no significant variances between London Hydro's amortization expense for the 2012 Bridge and the 2013 Test Year.

For the 2013 Test Year under MIFRS small variances exist for four asset categories (*OEB 1850, 1860, 1611, and 1955*). This is mainly related to the complexities associated with the reclass (transfer) of smart meters from the deferral accounts to regular fixed assets.

London Hydro's forecasted amortization expense for the proposed 2013 Test Year is calculated to be slightly lower ($25,670) than the calculations in Table 4-61, Page 129.

Table 4-57 - Depreciation and Amortization Expense – CGAAP for 2011

(OEB Appendix 2-CE)

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2011 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2011 Depreciation Expense (h) = (e) / (f)	2011 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1805	Land	385,690		385,690	-	385,690			$0		0
1806	Land Rights	315,951		315,951	6,283	319,093	24.48	4.08%	$13,035	13,036	-1
1808	Buildings (Substations)	1,128,336	199,958	928,378	-	928,378	33.29	3.00%	$27,888	27,885	3
1820	Distribution Station Equipment <50 kV	12,511,914	3,023,680	9,488,234	3,867,323	11,421,896	30.09	3.32%	$379,591	379,582	9
1830	Poles, Towers & Fixtures	35,556,585	538,477	35,018,108	2,329,323	36,182,770	24.927	4.01%	$1,451,549	1,451,539	10
1835	Overhead Conductors & Devices	48,199,822	395,616	47,804,206	3,526,704	49,567,558	24.048	4.16%	$2,061,193	2,061,140	53
1840	Underground Conduit	28,407,977	374,605	28,033,372	3,201,981	29,634,363	25.653	3.90%	$1,155,201	1,155,185	16
1845	Underground Conductors & Devices	109,646,839	2,701,146	106,945,693	4,777,384	109,334,385	26.324	3.80%	$4,153,411	4,153,383	28
1850	Line Transformers	69,527,135	1,461,838	68,065,297	4,274,795	70,202,695	24.27	4.12%	$2,892,690	2,892,693	-3
1855	Services (Overhead & Underground)	18,044,316	164,840	17,879,476	2,134,439	18,946,696	25.17	3.97%	$752,749	752,727	22
1860	Meters (3)	10,276,803	343,167	9,933,636	823,821	10,345,547	21.95	4.56%	$471,323	471,296	27
1908	Buildings & Fixtures (General Plant)	21,427,472	267,220	21,160,252	1,155,981	21,738,243	35.75	2.80%	$608,063	608,055	8
1915	Office Furniture & Equipment	1,284,755	181,231	1,103,524	134,227	1,170,638	11.35	8.81%	$103,140	103,162	-22
1920	Computer Hardware	3,157,337	1,121,029	2,036,308	406,298	2,239,457	5.884	17.00%	$380,601	380,552	49
1925	Computer Software	14,370,807	490,790	13,880,017	2,481,132	15,120,583	5.274	18.96%	$2,867,277	2,867,278	-1
1930	Transportation Equipment	9,812,906	5,317,303	4,495,603	223,290	4,607,248	6.57	15.22%	$701,255	701,306	-50
1935	Stores Equipment	295,020		295,020	-	295,020	10.07	9.93%	$29,297	29,290	7
1940	Tools, Shop & Garage Equipment	1,221,834	74,196	1,147,638	181,980	1,238,628	10.79	9.27%	$114,794	114,769	25
1945	Meter Department Equipment	105,506	2,449	103,057	-	103,057	15.05	6.64%	$6,848	6,847	1
1950	Power Operated Equipment	848,024	248,820	599,204	181,113	689,761	9.03	11.07%	$76,385	76,424	-39
1955	Communications Equipment	-		0	6,128	3,064	9.01	11.10%	$340	340	0
1960	Miscellaneous Equipment	-		0		0			$0	-	0
1980	System Supervisor Equipment	3,210,272		3,210,272	194,529	3,307,537	14.98	6.68%	$220,797	220,850	-53
1995	Contributions & Grants	-28,843,633		-28,843,633	-4,218,741	-30,953,004	25.71	3.89%	-$1,204,163	-1,204,147	-16
	Total - offset to Accumulated Amortization	360,891,668	16,906,365	343,985,303	25,687,990	356,829,298			17,263,263	17,263,192	71
						Other:					
						Less Depreciation on Vehicles & Equipment				(777,730)	
						Plus Depreciation for "Stranded Meters"				374,333	
						Sub total Other Items:				(403,397)	
						Grand Total Depreciation Expense				16,859,795	

Notes:

1 Board policy of the "half-year" rule - the applicant must ensure that additions in the year attract a half-year depreciation expense in the first year. London Hydro has complied with this requirement.

2 Year column represents average life spans for the group. Some asset groups contain multiple life spans. Some groups contain assets that become fully depreciation during 2012

3 Significant amount of meters were diposed in the year due to replacement by Smart Meters. The format of this table does not show those disposals. The result impacts the "Years" column

Table 4-58 - Depreciation and Amortization Expense – CGAAP for 2012

(OEB Appendix 2-CF)

Account	Description	Opening Regulatory Gross PP&E as at Jan 1, 2012 (a)	Less Fully Depreciated (b)	Net for Depreciation (c)	Additions (d)	Total for Depreciation (e) = (c) + ½ x (d) [1]	Years (f)	Depreciation Rate (g) = 1 / (f)	2012 Depreciation Expense (h) = (e) / (f)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (h) - (l)
1805	Land	385,690	-	385,690	-	385,690	0.00	n/a	0	-	0
1806	Land Rights	322,234	-	322,234	-	322,234	27.20	0.0368	11,847	11,835	12
1808	Buildings (Substations)	1,128,336	199,958	928,378	75,000	965,878	32.40	0.0309	29,811	29,807	4
1820	Distribution Station Equipment <50	16,379,236	3,161,188	13,218,048	192,500	13,314,298	30.00	0.0333	443,810	443,811	-1
1830	Poles, Towers & Fixtures	37,347,430	797,263	36,550,167	2,172,700	37,636,517	25.00	0.0400	1,505,461	1,505,461	0
1835	Overhead Conductors & Devices	51,330,910	585,744	50,745,166	3,196,400	52,343,366	24.26	0.0412	2,157,600	2,157,692	-92
1840	Underground Conduit	31,235,352	278,304	30,957,048	2,345,000	32,129,548	25.18	0.0397	1,275,995	1,276,038	-43
1845	Underground Conductors & Devices	111,723,077	5,232,554	106,490,523	4,647,600	108,814,323	26.09	0.0383	4,171,529	4,171,527	2
1850	Line Transformers	72,340,094	2,415,478	69,924,616	5,327,300	72,588,266	24.76	0.0404	2,932,030	2,932,035	-5
1855	Services (Overhead & Underground)	20,013,915	244,060	19,769,855	1,217,500	20,378,605	25.00	0.0400	815,144	815,144	0
1860	Meters	24,304,292	238,319	24,065,973	755,400	24,443,673	16.93	0.0591	1,443,723	1,443,651	72
1908	Buildings & Fixtures (General Plant)	22,479,216	162,982	22,316,234	800,000	22,716,234	35.56	0.0281	638,886	638,895	-9
1915	Office Furniture & Equipment	1,237,751	237,722	1,000,029	80,000	1,040,029	10.13	0.0987	102,688	102,684	4
1920	Computer Hardware	2,720,344	504,125	2,216,219	448,000	2,440,219	5.63	0.1777	433,740	433,722	18
1925	Computer Software	20,514,116	526,224	19,987,892	5,320,000	22,647,892	5.15	0.1942	4,398,930	4,398,868	62
1930	Transportation Equipment	9,491,683	4,834,823	4,656,860	1,815,000	5,564,360	6.74	0.1483	825,083	825,063	20
1935	Stores Equipment	295,020	19,122	275,898	5,000	278,398	29.47	0.0339	9,446	9,446	0
1940	Tools, Shop & Garage Equipment	1,329,620	163,139	1,166,481	130,000	1,231,481	10.97	0.0911	112,249	112,247	2
1945	Meter Department Equipment	103,056	59,192	43,864	93,000	90,364	10.00	0.1000	9,036	9,036	0
1950	Power Operated Equipment	1,029,137	258,334	770,803	75,000	808,303	8.00	0.1250	101,038	101,038	0
1955	Communications Equipment	3,343,534	-	3,343,534	445,000	3,566,034	15.79	0.0633	225,899	225,895	4
1960	Miscellaneous Equipment	-	-	0	-	0	10.00	0.1000	0	-	0
1980	System Supervisor Equipment	3,404,802	167,390	3,237,412	114,600	3,294,712	15.00	0.0667	219,647	219,647	0
1995	Contributions & Grants	-33,062,374	-	-33,062,374	-2,011,000	-34,067,874	25.00	0.0400	-1,362,715	-1,362,714	-1
	Total - offset to Accumulated Amortiza	399,396,471	20,085,921	379,310,550	27,244,000	392,932,550			20,500,876	20,500,828	48

Other:	
Less Depreciation on Vehicles & Equipment	(926,101)
Plus Depreciation for "Stranded Meters"	437,000
Rounding	273
Sub total Other Items:	(488,828)
Grand Total Depreiciation Expense	20,012,000

Notes:

1 London Hydro has followed the Board policy of the "half-year" rule for budgeting - the additions in the year attract a half-year depreciation expense in the first year.

2 The Opening asset cost account balance has been adjusted to include the assets to be transferred from Regulatory account 10.1555 from the Smart Meter project

3 Year column represents average life spans for the group. Some asset groups contain multiple life spans. Some groups contain assets that become fully depreciation during 2012

Table 4-59 - Depreciation and Amortization Expense – MIFRS for 2012

(OEB Appendix 2-CG)

Account	Description	Subsidiary	Subsidiary Description	Opening NBV as at Jan 1, 2012 [5] (a)	Additions (d)	Average Remaining Life of Opening NBV [4] (i)	Years (new additions only) [3] (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Opening NBV (j) = (a) / (i)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2012 Depreciation Expense (k) = (j) + (h)	2012 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (l)	Variance [2] (m) = (k) - (l)	Depreciation Expense on 2012 Full Year Additions (n)=((d))/(f)	Less Depreciation Expense on Assets Fully Depreciated during the year (o)	2012 Full Year Depreciation [6] (p) = (j) + (n) - (o)
1805	Land		Land	385,690		n/a		0.00%	$ -	$ -	$ -	$ -	$ -	$ -		$ -
806 (now 1612	Land Rights	410	Land Rights	173,669	0	11.5712	25	4.00%	$ 15,008.73	$ -	$ 15,008.73	$ 15,009.00	-$ 0.27	$ -		$ 15,008.73
1808	Buildings (Substations)	340	SS Building Overall	317,742	75,000	55.0200	75	1.33%	$ 5,775.03	$ 500.00	$ 6,275.03	$ 6,275.00	$ 0.03	$ 1,000.00		$ 6,775.03
1808	Buildings (Substations)	341	SS Roof	125,502	0	10.9163	30	3.33%	$ 11,496.75	$ -	$ 11,496.75	$ 11,497.00	-$ 0.25	$ -	$ 6,179.59	$ 5,317.16
1820	Distribution Station Equipment <50 kV	310	Distr Stn Equip	8,661,625	174,300	38.9559	45	2.22%	$ 222,344.37	$ 1,936.67	$ 224,281.04	$ 224,281.00	$ 0.04	$ 3,873.33		$ 226,217.70
1820	Distribution Station Equipment <50 kV	311	Battery Banks & Charges	174,095	0	4.6393	15	6.67%	$ 37,526.14	$ -	$ 37,526.14	$ 37,525.00	$ 1.14	$ -	$ 12,460.77	$ 25,065.37
1820	Distribution Station Equipment <50 kV	312	Digital Relays	238,925	17,400	11.8431	20	5.00%	$ 20,174.19	$ 435.00	$ 20,609.19	$ 20,609.00	$ 0.19	$ 870.00	$ 6,904.98	$ 14,139.21
820 (now 161(	Distribution Station Equipment <50 kV	313	Intangible - wholesale meter	1,171,429	0	27.2079	30	3.33%	$ 43,054.74	$ -	$ 43,054.74	$ 43,055.00	-$ 0.26	$ -		$ 43,054.74
1830	Poles, Tow ers & Fixtures	210	Poles, and Fixtures	18,521,156	2,119,500	35.8583	45	2.22%	$ 516,509.59	$ 23,550.00	$ 540,059.59	$ 540,059.00	$ 0.59	$ 47,100.00		$ 563,609.59
1835	Overhead Conductors & Devices	220	OH Primary Conductor	23,735,006	2,765,400	42.5033	50	2.00%	$ 558,427.37	$ 27,654.00	$ 586,081.37	$ 586,081.00	$ 0.37	$ 55,308.00		$ 613,735.37
1835	Overhead Conductors & Devices	221	Switches & Reclosers	6,157,463	347,700	37.6153	45	2.22%	$ 163,695.70	$ 3,863.33	$ 167,559.04	$ 167,559.00	$ 0.04	$ 7,726.67		$ 171,422.37
1840	Underground Conduit	110	Vaults & Manholes	21,251,690	2,106,900	54.2160	60	1.67%	$ 391,981.89	$ 17,557.50	$ 409,539.39	$ 409,540.00	-$ 0.61	$ 35,115.00		$ 427,096.89
1840	Underground Conduit	111	Vault & Manhole Roofs	1,147,314	171,300	17.9036	30	3.33%	$ 64,082.87	$ 2,855.00	$ 66,937.87	$ 66,938.00	-$ 0.13	$ 5,710.00	$ 12,248.58	$ 57,544.29
1845	Underground Conductors & Devices	130	TR-XB-TRXLPE Cable	46,003,341	4,117,000	7.5756	26.5	3.77%	$ 6,072,567.32	$ 77,679.25	$ 6,150,246.57	$ 6,150,265.00	-$ 18.43	$ 155,358.49	$ 3,152,873.26	$ 3,075,052.55
1845	Underground Conductors & Devices	131	SF6 & Vacuum Switchgear	1,344,366	93,000	25.8627	30	3.33%	$ 51,980.88	$ 1,550.00	$ 53,530.88	$ 53,531.00	-$ 0.12	$ 3,100.00		$ 55,080.88
1845	Underground Conductors & Devices	132	PILC Primary Cable	2,347,357	324,800	13.5372	30	3.33%	$ 173,400.48	$ 5,413.33	$ 178,813.81	$ 178,813.00	$ 0.81	$ 10,826.67	$ 48,186.82	$ 136,040.33
1845	Underground Conductors & Devices	133	Air Insulated Switchgear	397,041	0	5.7238	25	4.00%	$ 69,366.68	$ -	$ 69,366.68	$ 69,366.00	$ 0.68	$ -	$ 27,247.25	$ 42,119.43
1850	Line Transformers	150	Pad Mount Transformers	25,332,137	3,613,100	27.0270	35	2.86%	$ 937,290.01	$ 51,615.71	$ 988,905.72	$ 991,557.00	-$ 2,651.28	$ 103,231.43		$ 1,040,521.43
1850	Line Transformers	151	Network Transformers	4,731,986	415,200	27.5284	35	2.86%	$ 171,894.70	$ 5,931.43	$ 177,826.13	$ 177,825.00	$ 1.13	$ 11,862.86		$ 183,757.55
1850	Line Transformers	230	Overhead Transformers	12,284,075	974,500	26.8457	35	2.86%	$ 457,580.73	$ 13,921.43	$ 471,502.16	$ 471,500.00	$ 2.16	$ 27,842.86		$ 485,423.59
1855	Services (Overhead & Underground)	160	UG Secondary Services	6,566,593	735,800	25.3871	30	3.33%	$ 258,658.65	$ 12,263.33	$ 270,921.98	$ 270,921.00	$ 0.98	$ 24,526.67		$ 283,185.32
1855	Services (Overhead & Underground)	240	OH Secondary Services	6,055,647	444,700	51.6065	60	1.67%	$ 117,342.72	$ 3,705.83	$ 121,048.55	$ 121,049.00	-$ 0.45	$ 7,411.67		$ 124,754.39
1860	Meters	600	Regular Meters	2,032,127	93,000	11.7593	30	3.33%	$ 172,810.20	$ 1,550.00	$ 174,360.20	$ 174,359.00	$ 1.20	$ 3,100.00	$ 50,141.76	$ 125,768.44
1860	Meters	601	Digital Meters	15,002,219	462,000	13.2945	15	6.67%	$ 1,128,453.04	$ 15,400.00	$ 1,143,853.04	$ 1,143,857.00	-$ 3.96	$ 30,800.00		$ 1,159,253.04
1860	Meters	602	CT's and PT's	1,410,267	197,000	17.1218	30	3.33%	$ 82,366.75	$ 3,283.33	$ 85,650.08	$ 85,649.00	$ 1.08	$ 6,566.67	$ 7,858.94	$ 81,074.48
1908	Buildings & Fixtures (General Plant)	350	Buildings - Civil	4,519,670	475,000	39.6878	65	1.54%	$ 113,880.59	$ 3,653.85	$ 117,534.43	$ 117,535.00	-$ 0.57	$ 7,307.69		$ 121,188.28
1908	Buildings & Fixtures (General Plant)	351	Buildings - Roof	1,086,750	0	8.7069	25	4.00%	$ 124,814.80	$ -	$ 124,814.80	$ 124,814.00	$ 0.80	$ -	$ 80,399.84	$ 44,414.96
1908	Buildings & Fixtures (General Plant)	352	Buildings - Parking	51,681	0	1.3946	30	3.33%	$ 37,057.94	$ -	$ 37,057.94	$ 37,057.00	$ 0.94	$ -	$ 36,303.70	$ 754.24
1908	Buildings & Fixtures (General Plant)	353	Buildings - Fences	5,675	0	12.0027	60	1.67%	$ 472.81	$ -	$ 472.81	$ 473.00	-$ 0.19	$ -		$ 472.81
1908	Buildings & Fixtures (General Plant)	354	Electronic / Mechanical Systems	2,605,066	125,000	5.9874	12	8.33%	$ 435,091.36	$ 5,208.33	$ 440,299.69	$ 440,294.00	$ 5.69	$ 10,416.67	$ 168,276.73	$ 277,231.30
1908	Buildings & Fixtures (General Plant)	355	Electric / Mechanical Systems	4,373,344	200,000	3.7995	30	3.33%	$ 1,151,031.45	$ 3,333.33	$ 1,154,364.78	$ 1,154,357.00	$ 7.78	$ 6,666.67	$ 779,638.67	$ 378,059.45
1915	Office Furniture & Equipment	700	Office Furn & Equip	617,104	80,000	1.9098	5	20.00%	$ 323,124.93	$ 8,000.00	$ 331,124.93	$ 331,112.00	$ 12.93	$ 16,000.00	$ 190,781.08	$ 148,343.85
1920	Computer Hardw are	710	Computer Equip-Hardware	1,066,549	448,000	1.6305	3	33.33%	$ 654,123.89	$ 74,666.67	$ 728,790.56	$ 728,776.00	$ 14.56	$ 149,333.33	$ 372,511.18	$ 430,946.04
925 (now 1611	Computer Softw are	720	Computer Equip-Software = ALL 5 yr	12,874,972	5,195,000	3.2598	5	20.00%	$ 3,949,595.99	$ 519,500.00	$ 4,469,095.99	$ 4,469,095.00	$ 0.99	$ 1,039,000.00	$ 232,966.31	$ 4,755,629.68
925 (now 1611	Computer Softw are	721	Computer Software - 3yr	135,324	125,000	1.4183	3	33.33%	$ 95,412.82	$ 20,833.33	$ 116,246.15	$ 116,246.00	$ 0.15	$ 41,666.67	$ 72,604.25	$ 64,475.23
1930	Transportation Equipment	730	Transportation-Cars, Vans	892,859	390,000	6.1379	8	12.50%	$ 145,466.53	$ 24,375.00	$ 169,841.53	$ 169,849.00	-$ 7.47	$ 48,750.00		$ 194,216.53
1930	Transportation Equipment	740	Transportation-Large Vehicles	2,228,295	1,365,000	10.0515	12	8.33%	$ 221,687.81	$ 56,875.00	$ 278,562.81	$ 278,561.00	$ 1.81	$ 113,750.00		$ 335,437.81
1930	Transportation Equipment	750	Trailers	112,911	60,000	6.9125	10	10.00%	$ 16,334.32	$ 3,000.00	$ 19,334.32	$ 19,334.00	$ 0.32	$ 6,000.00	$ 692.56	$ 21,641.76
1935	Stores Equipment	760	Stores Equipment	31,019	5,000	2.6009	8	12.50%	$ 11,926.26	$ 312.50	$ 12,238.76	$ 12,239.00	-$ 0.24	$ 625.00	$ 4,745.59	$ 7,805.67
1940	Tools, Shop & Garage Equipment	770	Tools,Shop & Garage Equi	618,288	130,000	3.5078	8	12.50%	$ 176,260.90	$ 8,125.00	$ 184,385.90	$ 184,383.00	$ 2.90	$ 16,250.00	$ 61,298.33	$ 131,212.57
1945	Meter Department Equipment	780	Measurement & Test Equip	14,591	93,000	1.8754	8	12.50%	$ 7,780.21	$ 5,812.50	$ 13,592.71	$ 13,593.00	-$ 0.29	$ 11,625.00	$ 5,845.63	$ 13,559.58
1950	Pow er Operated Equipment	790	Power Operated Equipment	616,306	75,000	6.3871	8	12.50%	$ 96,492.30	$ 4,687.50	$ 101,179.80	$ 101,179.00	$ 0.80	$ 9,375.00		$ 105,867.30
1955	Communications Equipment	330	Communication Towers	487,851	0	30.0901	35	2.86%	$ 16,213.01	$ -	$ 16,213.01	$ 16,213.00	$ 0.01	$ -		$ 16,213.01
1955	Communications Equipment	331	Communication - Wireless	2,403,518	445,000	12.3354	15	6.67%	$ 194,847.19	$ 14,833.33	$ 209,680.52	$ 209,680.00	$ 0.52	$ 29,666.67		$ 224,513.85
1960	Miscellaneous Equipment		No assets of this type					0.00%	$ -	$ -	$ -		$ -	$ -		$ -
1980	System Supervisor Equipment	320	Scada RTU's	904,868	37,700	16.7287	20	5.00%	$ 54,090.75	$ 942.50	$ 55,033.25	$ 55,034.00	-$ 0.75	$ 1,885.00		$ 55,975.75
1980	System Supervisor Equipment	321	Scada Master Station	765,099	74,000	1.6747	10	10.00%	$ 456,857.35	$ 3,700.00	$ 460,557.35	$ 460,570.00	-$ 12.65	$ 7,400.00	$ 404,689.64	$ 59,567.71
1995	Contributions & Grants	1995	Contribution & Grants Credit	-26,094,597	-2,011,000	35.0520	40	2.50%	-$ 744,453.87	-$ 25,137.50	-$ 769,591.37	-$ 769,587.00	-$ 4.37	-$ 50,275.00		-$ 794,728.87
								0.00%	$ -	$ -	$ -		$ -	$ -		$ -
	Total Offset to Accumulated Amortization			215,885,605	26,559,300				19,281,899	1,003,386	$ 20,285,285.36	$ 20,287,927.00	-$ 2,641.64	$ 2,006,772.99	$ 5,734,855.46	$ 15,553,816.40

Other:	
Less Depreciation on Vehicles & Equipment	(568,923)
Plus Depreciation for "Stranded Meters"	437,000
Depreciation expense from amortization of Account 1575	-
Rounding	(4)
Sub total Other Items:	(131,927)
Grand Total Depreciation Expense	20,156,000

Table 4-60 - Depreciation and Amortization Expense – MIFRS for 2013

(OEB Appendix 2-CH)

Account	Description	Subsidiary	Subsidiary Description	Additions (d)	Years (new additions only) (f)	Depreciation Rate on New Additions (g) = 1 / (f)	Depreciation Expense on Additions [1] (h)=((d)*0.5)/(f)	2013 Depreciation Expense [1] (i)=2012 Full Year Depreciation + (h)	2013 Depreciation Expense per Appendix 2-B Fixed Assets, Column K (J)	Variance [2] (m) = (i) - (J)
1805	Land		Land			0.00%	$ -	$ -	$ -	$ -
1806 (now 1612)	Land Rights	410	Land Rights	0	25	4.00%	$ -	$ 15,008.73	$ 15,009.00	-$ 0.27
1808	Buildings (Substations)	340	SS Building Overall	75,000	75	1.33%	$ 500.00	$ 7,275.03	$ 7,275.00	$ 0.03
1808	Buildings (Substations)	341	SS Roof	0	30	3.33%	$ -	$ 5,317.16	$ 5,317.00	$ 0.16
1820	Distribution Station Equipment <50 kV	310	Distr Stn Equip	153,300	45	2.22%	$ 1,703.33	$ 227,921.04	$ 227,920.00	$ 1.04
1820	Distribution Station Equipment <50 kV	311	Battery Banks & Charges	0	15	6.67%	$ -	$ 25,065.37	$ 25,065.00	$ 0.37
1820	Distribution Station Equipment <50 kV	312	Digital Relays	15,300	20	5.00%	$ 382.50	$ 14,521.71	$ 14,522.00	-$ 0.29
1820 (now 1610)	Distribution Station Equipment <50 kV	313	Intangible - wholesale meter	0	30	3.33%	$ -	$ 43,054.74	$ 43,055.00	-$ 0.26
1830	Poles, Tow ers & Fixtures	210	Poles, and Fixtures	2,823,800	45	2.22%	$ 31,375.56	$ 594,985.15	$ 594,985.00	$ 0.15
1835	Overhead Conductors & Devices	220	OH Primary Conductor	3,320,500	50	2.00%	$ 33,205.00	$ 646,940.37	$ 646,940.00	$ 0.37
1835	Overhead Conductors & Devices	221	Switches & Reclosers	372,100	45	2.22%	$ 4,134.44	$ 175,556.81	$ 175,556.00	$ 0.81
1840	Underground Conduit	110	Vaults & Manholes	1,929,800	60	1.67%	$ 16,081.67	$ 443,178.55	$ 443,179.00	-$ 0.45
1840	Underground Conduit	111	Vault & Manhole Roofs	154,400	30	3.33%	$ 2,573.33	$ 60,117.62	$ 60,117.00	$ 0.62
1845	Underground Conductors & Devices	130	TR-XB-TRXLPE Cable	3,710,700	26.5	3.77%	$ 70,013.21	$ 3,145,065.76	$ 3,145,084.00	-$ 18.24
1845	Underground Conductors & Devices	131	SF6 & Vacuum Switchgear	93,200	30	3.33%	$ 1,553.33	$ 56,634.22	$ 56,634.00	$ 0.22
1845	Underground Conductors & Devices	132	PILC Primary Cable	205,600	30	3.33%	$ 3,426.67	$ 139,466.99	$ 139,468.00	-$ 1.01
1845	Underground Conductors & Devices	133	Air Insulated Switchgear	0	25	4.00%	$ -	$ 42,119.43	$ 42,118.00	$ 1.43
1850	Line Transformers	150	Pad Mount Transformers	3,327,400	35	2.86%	$ 47,534.29	$ 1,088,055.72	$ 1,096,796.00	-$ 8,740.28
1850	Line Transformers	151	Network Transformers	262,700	35	2.86%	$ 3,752.86	$ 187,510.41	$ 187,510.00	$ 0.41
1850	Line Transformers	230	Overhead Transformers	1,143,300	35	2.86%	$ 16,332.86	$ 501,756.44	$ 501,756.00	$ 0.44
1855	Services (Overhead & Underground)	160	UG Secondary Services	637,200	30	3.33%	$ 10,620.00	$ 293,805.32	$ 293,805.00	$ 0.32
1855	Services (Overhead & Underground)	240	OH Secondary Services	549,400	60	1.67%	$ 4,578.33	$ 129,332.72	$ 129,333.00	-$ 0.28
1860	Meters	600	Regular Meters	214,200	30	3.33%	$ 3,570.00	$ 129,338.44	$ 129,337.00	$ 1.44
1860	Meters - digital	601	Digital Meters	445,000	15	6.67%	$ 14,833.33	$ 1,174,086.38	$ 1,172,921.00	$ 1,165.38
1860	Meters	602	CT's and PT's	82,000	30	3.33%	$ 1,366.67	$ 82,441.14	$ 82,441.00	$ 0.14
1908	Buildings & Fixtures (General Plant)	350	Buildings - Civil	75,000	65	1.54%	$ 576.92	$ 121,765.20	$ 121,766.00	-$ 0.80
1908	Buildings & Fixtures (General Plant)	351	Buildings - Roof	0	25	4.00%	$ -	$ 44,414.96	$ 44,414.00	$ 0.96
1908	Buildings & Fixtures (General Plant)	352	Buildings - Parking	200,000	30	3.33%	$ 3,333.33	$ 4,087.57	$ 4,086.00	$ 1.57
1908	Buildings & Fixtures (General Plant)	353	Buildings - Fences	0	60	1.67%	$ -	$ 472.81	$ 473.00	-$ 0.19
1908	Buildings & Fixtures (General Plant)	354	Electronic / Mechanical Systems	75,000	12	8.33%	$ 3,125.00	$ 280,356.30	$ 280,351.00	$ 5.30
1908	Buildings & Fixtures (General Plant)	355	Electric / Mechanical Systems	225,000	30	3.33%	$ 3,750.00	$ 381,809.45	$ 381,802.00	$ 7.45
1915	Office Furniture & Equipment	700	Office Furn & Equip	80,000	5	20.00%	$ 8,000.00	$ 156,343.85	$ 156,331.00	$ 12.85
1920	Computer Hardw are	710	Computer Equip-Hardware	480,000	3	33.33%	$ 80,000.00	$ 510,946.04	$ 510,931.00	$ 15.04
1925 (now 1611)	Computer Softw are - 5 yr	720	Computer Equip-Software	5,405,000	5	20.00%	$ 540,500.00	$ 5,296,129.68	$ 5,273,022.00	$ 23,107.68
1925 (now 1611)	Computer Softw are - 3 yr	721	Computer Software - 3yr	115,000	3	33.33%	$ 19,166.67	$ 83,641.90	$ 83,643.00	-$ 1.10
1930	Transportation Equipment	730	Transportation-Cars, Vans	375,000	8	12.50%	$ 23,437.50	$ 217,654.03	$ 217,662.00	-$ 7.97
1930	Transportation Equipment	740	Transportation-Large Vehicles	835,000	12	8.33%	$ 34,791.67	$ 370,229.47	$ 370,229.00	$ 0.47
1930	Transportation Equipment	750	Trailers	90,000	10	10.00%	$ 4,500.00	$ 26,141.76	$ 26,141.00	$ 0.76
1935	Stores Equipment	760	Stores Equipment	5,000	8	12.50%	$ 312.50	$ 8,118.17	$ 8,118.00	$ 0.17
1940	Tools, Shop & Garage Equipment	770	Tools,Shop & Garage Equi	130,000	8	12.50%	$ 8,125.00	$ 139,337.57	$ 139,334.00	$ 3.57
1945	Meter Department Equipment	780	Measurement & Test Equip	20,000	8	12.50%	$ 1,250.00	$ 14,809.58	$ 14,809.00	$ 0.58
1950	Pow er Operated Equipment	790	Power Operated Equipment	110,000	8	12.50%	$ 6,875.00	$ 112,742.30	$ 112,741.00	$ 1.30
1955	Communications Equipment	330	Communication Towers	0	35	2.86%	$ -	$ 16,213.01	$ 16,142.00	$ 71.01
1955	Communications Equipment	331	Communication - Wireless	0	15	6.67%	$ -	$ 224,513.85	$ 214,456.00	$ 10,057.85
1960	Miscellaneous Equipment		No assets of this type			0.00%	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	320	Scada RTU's	37,000	20	5.00%	$ 925.00	$ 56,900.75	$ 56,901.00	-$ 0.25
1980	System Supervisor Equipment	321	Scada Master Station	81,500	10	10.00%	$ 4,075.00	$ 63,642.71	$ 63,656.00	-$ 13.29
1995	Contributions & Grants	1995	Contribution & Grants Credit	-1,832,000	40	2.50%	-$ 22,900.00	-$ 817,628.87	-$ 817,624.00	-$ 4.87
										$ -
	Total Offset to Accumulated Amortization			26,021,400			987,381	16,541,197	16,515,527	25,670

Other:	
Less Depreciation on Vehicles & Equipment	(726,773)
Plus Depreciation for "Stranded Meters"	-
Depreciation expense from amortization of Account 1575	118,000
Rounding	(754)
Sub total Other Items:	(609,527)
Grand Total Depreciation Expense	15,906,000

TAXES OR PAYMENTS IN LIEU OF TAXES (“PILs”)

Income and Capital Tax:

As a wholly owned subsidiary of the Corporation of the City of London, London Hydro is exempt from income taxes under the Income Tax Act (Canada). Pursuant to Section 93 of the Electricity Act, 1998, as amended, London Hydro is required to make payments in lieu of taxes (“PILs”) to the Ontario Electricity Financial Corporation.

The amount of PILs payable is equivalent to the income and capital taxes that would be paid if London Hydro was a taxable corporation under the Income Tax Act (Canada).

Table 4-61, below, provides a summary of income and capital tax for 2009 Board Approved, 2009 Actual, 2010 Actual, 2011 Actual, as well as the 2012 Bridge Year and the proposed 2013 Test Year under both CGAAP and MIFRS.

Table 4-61 – Summary of Income and Capital Taxes 2009 to 2013

Summary of Income and Capital Taxes 2009 to 2013

	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 CGAAP	2013 CGAAP	2012 MIFRS	2013 MIFRS
Income tax rate	33.00%	33.00%	30.99%	28.25%	26.50%	26.50%	26.50%	26.50%
Income taxes - current	1,788,777	3,283,466	2,239,105	1,522,783	740,579	2,019,576	511,511	696,644
Ontario capital tax	473,233	439,535	160,066	-	-	-	-	-
Total PILs	**2,262,010**	**3,723,001**	**2,399,171**	**1,522,783**	**740,579**	**2,019,576**	**511,511**	**696,644**

A Detailed Tax Calculation schedule is provided in Table 4-62, on Page 130 supporting income and capital tax amounts displayed in Table 4-61 above. This schedule calculates and compares income tax expense for rate recovery, as well as capital tax for 2009 to 2013 and excludes non-utility income and expenses.

Utility net income listed for the 2009 Board Approved and proposed 2013 Test Year are at deemed net income amounts for rate making purposes and therefore include deemed interest.

Income tax for the 2009 taxation year was higher than the 2009 Board Approved amount mainly as a result of higher than anticipated utility net income and capital cost allowance (“CCA”). In addition, in order to defer income tax expense, London Hydro began claiming CCA on smart meters in 2009 and, therefore, also began to recognize smart meter net funding adders into taxable income as discussed below.

Table 4-62 – Detailed Tax Calculations 2009 to 2013

Detailed Tax Calculations 2009 to 2013								
Description	**2009 Board Approved**	**2009 (Actual)**	**2010 (Actual)**	**2011 (Actual)**	**2012 Bridge (CGAAP)**	**2013 Test (CGAAP)**	**2012 Bridge (MIFRS)**	**2013 Test (MIFRS)**
Utility net income	**7,219,445**	**8,281,257**	**8,898,022**	**7,792,628**	**6,738,000**	**9,750,453**	**4,807,000**	**9,834,653**
Additions to Accounting Income:								
Income tax expense		2,885,000	2,353,000	1,527,000	556,000		1,808,000	
Depreciation and amortization	15,919,000	15,535,769	16,503,528	17,637,525	20,938,000	21,792,200	20,725,000	16,633,200
Meals and entertainment	30,000	35,580	34,234	34,545	38,700	37,200	38,700	37,200
Non-deductible company pension plans	495,000	376,700	450,000	776,100	525,000	525,000	525,000	525,000
Apprenticeship and Co-op tax credits	70,000	6,000	45,234	39,014	48,000	48,000	48,000	48,000
SRED Tax Credits		237,879	77,367	101,791	105,000	105,000	105,000	105,000
Non-deductible interest / swap agreement loss		(2,133)	369,512	192,256				
Ontario capital tax for accounting purposes		420,000	182,535	72,948				
Smart meter net funding adder		1,600,952	1,277,211	1,839,120	(4,717,283)		(4,717,283)	
Smart meter amortization from deferral account					2,593,363		2,593,363	
Total Additions	**16,514,000**	**21,095,747**	**21,292,621**	**22,220,299**	**20,086,780**	**22,507,400**	**21,125,780**	**17,348,400**
Deductions from Accounting Income:								
Capital Cost Allowance	17,875,731	18,024,504	21,699,551	23,265,094	23,065,599	23,675,614	23,038,007	23,593,010
Gain on disposal of assets	49,300	49,035	104,333	80,377	64,500	64,000	64,500	64,000
Cumulative eligible capital deduction			27,879	43,664	40,608	37,765	40,608	37,765
Sale of scrap for accounting purposes		119,871	170,480	311,357	150,000	150,000	150,000	150,000
Tax credits for accounting purposes		84,851	299,372	110,141				
Ontario capital tax		439,535	160,066					
Roof replacement		359,690		530,328				
Total Deductions	**17,925,031**	**19,077,486**	**22,461,681**	**24,340,961**	**23,320,707**	**23,927,379**	**23,293,115**	**23,844,775**
Total tax adjustments to accounting income	**(1,411,031)**	**2,018,261**	**(1,169,060)**	**(2,120,662)**	**(3,233,927)**	**(1,419,979)**	**(2,167,335)**	**(6,496,375)**
Taxable Income Prior to Adjusting Revenue to PILs	**5,808,414**	**10,299,518**	**7,728,962**	**5,671,966**	**3,504,073**	**8,330,474**	**2,639,665**	**3,338,278**
Corporate Income Tax Rate	33.00%	33.00%	30.99%	28.25%	26.50%	26.50%	26.50%	26.50%
Total PILs before small business deduction	1,916,777	3,398,841	2,395,344	1,602,214	928,579	2,207,576	699,511	884,644
Small business deduction (provincial)	-	-	-	(36,240)	(35,000)	(35,000)	(35,000)	(35,000)
Total PILs before gross up and tax credits	**1,916,777**	**3,398,841**	**2,395,344**	**1,565,974**	**893,579**	**2,172,576**	**664,511**	**849,644**
Tax credits (Apprenticeship Tax Credits)	(70,000)	(45,234)	(39,014)	(34,191)	(39,000)	(39,000)	(39,000)	(39,000)
Tax credits (Co-Op)		-	-	(9,000)	(9,000)	(9,000)	(9,000)	(9,000)
Tax credits (SRED)	(58,000)	(70,141)	(117,225)	-	(105,000)	(105,000)	(105,000)	(105,000)
	(128,000)	**(115,375)**	**(156,239)**	**(43,191)**	**(153,000)**	**(153,000)**	**(153,000)**	**(153,000)**
Total PILs before gross up and Capital Tax	**1,788,777**	**3,283,466**	**2,239,105**	**1,522,783**	**740,579**	**2,019,576**	**511,511**	**696,644**
Calculation of Utility Income Taxes								
Income Taxes (grossed-up)	2,669,816	4,900,695	3,244,693	2,122,284	994,082	2,732,104	683,602	934,484
Ontario Capital Tax	473,233	439,535	160,066	-	-	-	-	-
Total Taxes (PIL's) for rate recovery	**3,143,049**	**5,340,230**	**3,404,759**	**2,122,284**	**994,082**	**2,732,104**	**683,602**	**934,484**
Tax Rates								
Federal Tax	19.00%	19.00%	18.00%	16.50%	15.00%	15.00%	15.00%	15.00%
Provincial Tax	14.00%	14.00%	12.99%	11.75%	11.50%	11.50%	11.50%	11.50%
Total Tax Rate	**33.00%**	**33.00%**	**30.99%**	**28.25%**	**26.50%**	**26.50%**	**26.50%**	**26.50%**
Calculation of Ontario Capital Tax								
Total Rate Base	225,325,979	210,348,889	230,190,000	239,619,869	263,445,774	267,282,141	263,494,929	269,590,258
Less: Exemption	15,000,000	15,000,000	15,000,000	-	-	-	-	-
Taxable Capital / Deemed taxable capital	**210,325,979**	**195,348,889**	**215,190,000**	**239,619,869**	**263,445,774**	**267,282,141**	**263,494,929**	**269,590,258**
Ontario Capital Tax Rate	0.2250%	0.2250%	0.0744%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Ontario Capital Tax	**473,233**	**439,535**	**160,066**	**-**	**-**	**-**	**-**	**-**

Under CGAAP, PILs for rate recovery in the 2013 Test Year of $2,732,104 is $410,945 lower than the 2009 Board Approved amounts and $1,738,022 higher than the 2012 Bridge Year.

Under MIFRS, PILs for rate recovery in the 2013 Test Year of $934,484 is $2,208,565 lower than the 2009 Board Approved amounts and $250,882 higher than the 2012 Bridge Year.

Major factors contributing to this significant reduction in PILs are tax rate reductions from 33.0% in 2009 to 26.5% in 2013, increased CCA on smart meters and lower revenue requirement as a result of implementation of MIFRS.

Reconciliation between actual and regulatory taxable income:

A reconciliation between actual taxable income as reported in annual corporate income tax returns as filed with the Ministry of Finance in comparison to regulatory taxable income for the 2009, 2010 and 2011 taxation years is provided below:

Table 4-63 – Reconciliation of Regulatory Taxable Income

Reconciliation of Regulatory Taxable Income for 2009 to 2011	2009 Actual	2010 Actual	2011 Actual
Taxable income as filed with Ministry of Finance	10,296,226	7,699,018	5,469,972
Remove non-distribution activities:			
London Hydro renewable generation			
Revenues			(89,468)
Operating expenditures		22,692	51,911
CCA			233,809
		22,692	196,252
Non-utility donations	3,292	7,252	5,742
	3,292	29,944	201,994
Regulatory taxable income	**10,299,518**	**7,728,962**	**5,671,966**

Smart meter net funding adder:

As addressed above, London Hydro began to take advantage of tax deferral savings relating to CCA on smart meters commencing in 2009 in order to defer income tax expense and, accordingly, net funding adders received were included in the calculation of taxable income. This provides for an increase to utility net income in the 2009, 2010 and 2011 taxation years, and an equal and offsetting decrease to utility net income in the 2012 taxation year, when the return on smart meter rate base is recognized for accounting purposes. Otherwise, taxable income calculations exclude all other amounts due to timing differences associated with the tax treatment of regulatory assets and liabilities.

Capital tax:

The Ontario capital tax was eliminated effective July 1, 2010 and, accordingly, no associated provision has been made in this Application for the proposed 2013 Test Year.

Income tax credits:

A summary of income tax credits for the 2009, 2010 and 2011 taxation years, as well as projected amounts for the 2012 Bridge Year and 2013 Test Year are provided below. These income tax credits are deducted in the calculation of current taxable payable, and are associated with Scientific Research and Experimental Development ("SR&ED"), Ontario Apprenticeship Training, Federal Apprenticeship Job Creation and Co-operative Education Tax Credits.

There is no claim for a Scientific Research and Experimental Development (SR&ED) tax credit listed in the schedule above for the 2011 taxation year as this claim is in progress, but has not yet been filed with the Ministry of Finance at the time of preparing this Application.

Table 4-64 – Summary of Tax Credits 2009 to 2013

Summary of Tax Credits 2009 - 2013					
	2009 Actual	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Investment tax credits:					
SR&ED	70,141	117,225	-	105,000	105,000
Apprenticeship tax credits:					
Eligible apprentice	8,822	3,781	4,027	7,000	7,000
Eligible apprentice	8,822	1,233	4,164	7,000	7,000
Eligible apprentice	8,822	10,000	10,000	10,000	10,000
Eligible apprentice	6,384	10,000	10,000	10,000	10,000
Eligible apprentice	6,384	10,000	-	-	-
	39,234	35,014	28,191	34,000	34,000
Job creation tax credits:					
Eligible apprentice	2,000	2,000	2,000	2,000	2,000
Eligible apprentice	2,000	2,000	2,000	2,000	2,000
Eligible apprentice	2,000	-	2,000	1,000	1,000
	6,000	4,000	6,000	5,000	5,000
Co-operative education					
Eligible student	-	-	3,000	3,000	3,000
Eligible student	-	-	3,000	3,000	3,000
Eligible student	-	-	3,000	3,000	3,000
	-	-	9,000	9,000	9,000
	115,375	**156,239**	**43,191**	**153,000**	**153,000**

Cumulative eligible capital – CEC:

Details with respect to cumulative eligible capital ("CEC") are provided below. London Hydro has claimed the maximum CEC deduction available for the 2013 Test Year.

Summary of Cumulative Eligible Capital 2010 - 2013

	2010 Actual	2011 Actual	2012 Bridge Year	2013 Test Year
Additions during year	531,019	337,853	-	-
Balance, beginning of year	-	370,386	580,111	539,503
Additions x 3/4	398,265	253,390	-	-
CEC x 7%	**(27,879)**	**(43,664)**	**(40,608)**	**(37,765)**
Balance, end of year	370,386	580,111	539,503	501,738

Capital cost allowance – CCA:

Details with respect to capital cost allowance as displayed in the Detailed Tax Calculation schedule have been provided under Appendix 4F. London Hydro has claimed the maximum CCA deduction available for the proposed 2013 Test Year.

Appendix Items:

In support of its PILs expense, London Hydro has provided the following documentation as Appendices:

- 4E: OEB Income Tax PILS Work Form for the proposed 2013 Test Year
- 4F: Capital Cost Allowance schedules for 2009 Board Approved to 2013 Test Year
- 4G: Corporate tax return filing for the 2011 taxation year
- 4H: Notice of Reassessment for the 2010 taxation year
- 4I: Notice of Assessment for the 2009 taxation year
- 4J: Notice of Reassessment for the 2008 taxation year

The Notice of Assessment for the 2011 taxation year has not been provided in the Appendix since it had not been issued by the Ministry of Finance at the time of preparing this Application.

GREEN ENERGY ACT ("GEA") PLAN O&M COSTS

London Hydro is filing a GEA plan, as part of this Application, in accordance with the Board's Filing Requirements. London Hydro is required to file to the Board in a cost of service rate application a Green Energy Act Plan ("GEA Plan") which is noted in at Exhibit 2, Page 21.

A copy of the GEA Plan, together with the OPA's letter of comment dated August 10, 2012 is provided in Exhibit 2, Appendix 2G and Appendix 2H respectively.

The GEA Plan has been prepared in accordance with the Board's *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-003), dated April 26, 2012.

London Hydro has prepared a Basic Green Energy Act Plan, which was filed with the OPA in June 2012. The OPA has provided their comments on the Basic GEA Plan and acknowledged that: "London Hydro's GEA Plan is reasonably consistent with the OPA's information regarding renewable energy generation applications to date".

Operation and Maintenance costs for renewable generation connection and smart grid have been recorded in compliance with the Green Energy Act and the Filing Requirements as updated May 17, 2012. The following deferral accounts, 1531 Renewable Generation Connection Capital, 1532 Renewable Generation OM&A and 1535 Smart Grid OM&A Deferral Account have been used to record required renewable generation connection and smart grid expenditures.

However, London Hydro is not requesting recovery of operation and maintenance costs for renewable generation connection and smart grid, in this Application. As the renewable generation connection and smart grid developments are in the early stages of development, with minimal amounts having been spent to date, London Hydro respectfully requests in this Application to continue the use of these deferral accounts until such time when substantial account balances are present, then will apply for prudence review and recovery.

These accounts are detailed in Exhibit 9, Table 9-3, on Page 17.

CONSERVATION & DEMAND MANAGEMENT ("CDM") COSTS

Historically, London Hydro conducted conservation and demand management programs that were funded by the Ontario Power Authority ("OPA") as well as from the rate payers. In the 2009 Cost of Service application $134,300 was included in OEB account 5415 Energy Management for recovery from distribution rates. Actual historical costs in 2009 and 2010 were $219,195 and $34,025, respectively.

Effective January 1, 2011, and in accordance with the Board's Conservation and Demand Management Code ("CDM Code") (EB-2010-0215), issued September 16, 2010, funding for distributors for the 2012 – 2014 period will be provided by the OPA. London Hydro has, therefore, excluded all costs related to CDM programs from this Application.

London Hydro will not be applying in this Application for any Board approval for CDM programs that are being offered outside the OPA-Contracted Province-Wide Programs.

LRAM Variance Account ("LRAMVA) for 2011-2014:

London Hydro is seeking approval to use the LRAM Variance Account ("LRAMVA") commencing year 2013 to capture the variance between the Board-approved CDM forecast and the actual results at the customer rate level. The Board has established Account 1568 LRAMVA to capture this variance.

In accordance with the *Guidelines for Electricity Distributor Conservation and Demand Management* [EB-2012-0003], issued April 26, 2012, London Hydro understands that the OPA will measure CDM results attributable to the four year targets on a net basis. Consistent with past practices, it is expected the net level of savings will be used for LRAM calculations. As a result, it is London Hydro's view the units used for the 2013 LRAM variance account should also be on a net basis.

Lost Revenue Adjustment Mechanism ("LRAM") / SSM for pre 2011 CDM Activities:

In its 2012 IRM rate application (EB-2011-0181) London Hydro requested the recoveries of amounts related to the Board's Lost Revenue Adjustment Mechanism ("LRAM"). In its Decision in that proceeding, the Board approved rate riders for the recovery of forgone revenue related to 2010 CDM activity. London did not apply for SSM for pre 2011 CDM activities.

The LRAM Rate Rider is effective until April 30, 2013.

Lost Revenue Adjustment Mechanism ("LRAM") / SSM for 2011 and 2012 CDM Activities:

London Hydro intends to file with its 2014 IRM rate application for recoveries of persistent 2010 LRAM (referenced in the 2012 IRM rate application - EB-2011-0181), as well as recoveries for LRAM for both 2011 and 2012. The Board's Conservation and Demand Management Code ("CDM Code") (EB-2010-0215), issued September 16, 2010, provides that the distributor is required to provide documentation of the distributor's results for OPA Contracted Province-Wide Programs.

London Hydro's decision to await its 2014 IRM rate application to apply for LRAM recoveries is based primarily on the delay of the OPA final evaluation CDM report for 2011. Further, as a rate mitigation consideration reducing impact on our customers, London Hydro requests to delay recoveries from our customers at this time.

APPENDIX 4A – ELECTRICITY SECTOR COUNCIL REPORT

Knowledge Management & Transfer for the Electricity Industry in Canada

Investing Today for a Brighter Future

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Knowledge Management & Transfer for the Electricity Industry in Canada

Investing Today for a Brighter Future

electricity SECTOR COUNCIL

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Canada

EXECUTIVE SUMMARY

> When organizations consume material assets, they often depreciate in value. On the other hand, when organizations use knowledge resources, these assets tend to increase in value given that both the giver and receiver are enriched as a result of the transaction.
>
> *Working Knowledge, Davenport & Prusak, 2000*

THE BUSINESS CASE FOR INVESTING IN KNOWLEDGE MANAGEMENT/KNOWLEDGE TRANSFER

In today's knowledge-based economy *knowledge* is viewed as an organization's best sustainable source for a competitive advantage. In the electricity sector, knowledge has tended to accumulate within an organization primarily because the workforce has been stable with employees making their career in one organization, if not the sector. A growing concern is the estimated 28.8% of the electricity sector's workforce that is projected to retire in the next half decade. The Electricity Sector Council's (ESC) 2008 Labour Market Information (LMI) Study predicted there will be an insufficient supply of workers to fill the demand of the sector to meet the growing consumer demand for electricity. This gap exists at all levels of the industry, from engineers through technicians and trades people. This means that the sector will have to double its hiring of recent post-secondary graduates at a time when the demand for such workers is increasing in many other sectors as well[1].

Today, the demographics and changing dynamics of the Canadian labour force poses a number of risks to the evolution of the electricity sector including:

- ⇒ **The Loss of Knowledge Unique to Organizations**: Legacy systems, innovations in transmission and distribution, trouble shooting, etc. – the loss of which could have significant implications for business competitiveness, productivity, and the overall health and safety in the harnessing and distribution of electricity.
- ⇒ **Ramping up New Employees:** The demographics dictate that new employees will need to be ramped up much faster than in the past in order to replace retiring employees (most likely career employees) who have accumulated years of experience and knowledge.[2]
- ⇒ **New Skill Requirements:** The need to develop new skills in order to deal with emerging technologies such as those related to smart grids and new electricity sub-sectors such as wind and solar.
- ⇒ **Facing the Workforce of the Future:** A new generation of workers who no longer plan to have a career in one industry, let alone the same sector. They are more highly mobile and change jobs frequently, taking their technological savvy and any knowledge they have gained with them.

The productivity level of the workforce is the electricity sector's key competitive driver. Losing many experienced, specialized, technical people and hiring new, knowledgeable but inexperienced, workers may have a detrimental impact on productivity, regulatory compliance and safety levels.

Companies within the sector will need to focus and invest in knowledge management (KM) and knowledge transfer (KT) in order to effectively harness their knowledge and business intelligence and transfer this knowledge to current and new employees.

[1] Electricity Sector Council *Powering Up the Future: 2008 Labour Market Information Study – Full Report. http://www.brightfutures.ca/lmi/etc/en/docs/LMI%20REPORT%20ENGLISH%20FINAL%20LONG%20Nov%2024.pdf*
[2] Greenes, K. & Piktialis, D. (2008a) Bridging the Gaps: How to Transfer Knowledge in Today's Multigenerational Workplace

1. INTRODUCTION

1.1 BACKGROUND

The electricity sector is integral to the economic and social stability of Canada. While reliance on the more traditional hydroelectric power remains high (accounting for over 60% of Canada's electricity supply), experts predict the use of solar, geothermal and tidal power, as well as wind and other renewable sources of electricity, will increase dramatically over the next 10 years.[4]

The electricity sector has primarily relied on the same technology for the last 100 years, with the exception of more recently discovered ways of harnessing electricity such as nuclear, solar, etc. This has led to the requirement to have employees skilled in both legacy systems and technology as well as new innovations and technologies to support both traditional and growing renewable sub-sectors of power generation including wind and solar. At the same time, the focus in Canada is turning toward revitalizing the sector's aging infrastructure including power generation and transmission networks and systems.

Emerging new technologies and aging of current technology and infrastructure are not the sector's only concern. Recent studies conducted by the Electricity Sector Council (ESC), augmented by several other labour market studies[5], anticipate profound changes to the sector's workforce over the next decade. The sector is experiencing substantial structural change in human resources (HR) and technology advances. An estimated 28.8%[6] of the sector workforce is projected to retire in the next half decade. The majority of positions in the sector require some form of post-secondary education. The competencies and skills required in the sector are constantly being upgraded by new technology and management systems that are being introduced. Hiring for the future is not necessarily the same as hiring for today.

This has implications for both maintaining and sustaining a skilled workforce. For power producers, including both private and public, this means new skill sets and knowledge bases at all levels of the business to support research and innovation, changing operations (i.e. service delivery and distribution), and improvements to business processes, services, and products. Technology (automation and computerized systems) and the changing business environment are driving the need for new skill requirements. However, within the energy sector, the "new" doesn't necessarily drive out the old. There will continue to be the need for staff that are experienced and knowledgeable with operating legacy systems. Hence, existing staff need development so that they are ready to fill vacancies in senior and critical specialist/technical positions that require significant experience in the field but also an ability to adapt to new business realities and requirements. New workers require orientation and training to bring them to a competent level of performance. Sector representatives generally note that new graduates require four years on-the-job experience to reach full competency.

Given the changing labour market realities including innovation and changing demographics, if actions are not taken today, then the sector will not be able to maintain its current competitive position. Meeting these unique needs will be a challenge, and despite these changes impacting the sector, the ESC estimated that one-third of the industry does not have workforce planning and knowledge transfer tools and processes in place[7]. Without such tools, strategies and processes in place, corporate memory will be lost which has grave implications for competitive positioning, safety, productivity and business continuity, not to mention the need for understanding company-specific intellectual knowledge and know-how.

[4] Electricity Sector Council http://www.brightfutures.ca/resource-centre/trends.html.
[5] Conference Board of Canada; Ontario Chamber of Commerce to name two.
[6] Electricity Sector Council *Powering Up the Future: 2008 Labour Market Information Study – Full Report*
[7] Electricity Sector Council *Powering Up the Future: 2008 Labour Market Information Study – Full Report*

3. THE KM/KT BUSINESS DRIVERS

Section Highlights

- ⇒ Knowledge is an organization's best sustainable source of competitive advantage.
- ⇒ The threat to most employers is a knowledge shortage – not simply a labour shortage.
- ⇒ The Sector faces a number of recruitment challenges based on the complexity of the sector, new emerging technologies, the need for specialized knowledge, particularly in relation to legacy systems and an aging workforce.
- ⇒ The challenge is to know where knowledge, that is critical to supporting your business's competitive advantage, resides and how to harness it before that knowledge walks out the door.

In today's knowledge-based global economy, businesses and industries depend on progressively higher levels of education, and for many workers, the speed of change has necessitated continuous learning.[9] Increasingly, Canada has recognized the importance of human capital formation and utilization as a critical part of its competitive advantage. The acquisition and application of skills and knowledge (including higher level educational attainment) have become a basis for increased productivity, economic growth, and are associated with better labour market outcomes, such as higher earnings, higher labour force participation rates and lower unemployment rates. Numerous authors have pointed to knowledge as an organization's best sustainable source of competitive advantage and recent academic and popular media attention on organizational knowledge creation, capture, and transfer attest to a widespread acceptance of this idea.[10]

3.1 KEY KM/KT BUSINESS DRIVERS WITHIN THE ELECTRICITY SECTOR

Traditionally, employees in the electricity sector tended to be long term, joining the company upon graduation from university/college or completion of apprenticeship training. Workers learned on-the-job as they were gradually promoted to more experienced and specialized posts. Because of the technical and regulated nature of the majority of occupations in the sector, the industry maintains that even with the right training and qualifications, it takes four years after graduation for a new hire to be fully proficient in their position. During the downsizing and consolidation years (late 80s and early 90's), few companies recruited new employees. This has led to a critical situation whereby remaining employees are leaving (retiring) and there are no employees ready to take their place. The situation is even more serious since the industry is growing, particularly in the newer electricity sub-sectors, and employers not only need to replace retiring workers, but require additional workers with new skills and competencies.

At the same time, experience within the sector is that colleges and other trade education programs are not readily available and will not provide enough graduates to fill the gap in the labour force market. Because technology is evolving at a fast pace, especially in the electricity sector, there is also concern that educational programs are not adapting to the technological changes in the sector and responding to the industry's needs by producing graduates with the appropriate level of technical skills and knowledge[11].

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[9] Kevin Milligan, Assistant Professor of Economics at the University of British Columbia and a Research Fellow with the C.D. Howe Institute

[10] Davenport, T. H., DeLong, D. W., & Beers, M. C. (1998). Successful knowledge management projects. *Sloan Management Review, 39*(2): 43-57.; Costa, Dan. (1999, July). Knowledge is power. Computer Shopper, 252-254.; and Marchand, D. & Davenport, T. H. (2000). Is KM just good information management. In D. Marchand & T. H. Davenport (Eds.), Mastering Information Management. New York: Financial Times-Prentice Hall.

[11] Electricity Sector Council Succession Planning Best Practices and Tools for the Canadian Electricity and Renewable Sector: Final Report. pg. 24, 2008.

COMPLEXITY OF THE SECTOR

The electricity sector covers a wide range of sub-sectors, including hydroelectric, solar, wind and nuclear power; at a broader level the energy sector includes oil, natural gas and fossil fuels, in addition to other renewable sustainable energy resources. The sector is highly regulated, which means it is a complex working environment operating under strict training, certification, health and safety requirements. High health and safety rates are integral to achieving high productivity, which in turn is required to maintain an advantage in a highly competitive global sector. Losing a significant number of long serving employees, coupled with few recent hires, means that the regulatory environment is potentially being compromised, particularly health and safety. It is becoming increasingly critical that organizations within the sector be able to hire graduates now and to somehow fast-track their long learning curve and transfer critical knowledge and expertise so they are ready to replace those who are expected to leave the sector in the coming years.[12]

EMERGING TECHNOLOGIES

The electricity sector has primarily relied on the same technology for the last 100 years, with the exception of more recently discovered ways of harnessing electricity such as nuclear, solar, etc. This has also changed with the introduction of smart grids and new electricity industries such as wind and solar. These technology changes are driving new skill requirements. However, the ongoing reliance on legacy systems, particularly for specialized programs and those that have been custom built in-house, has meant that organizations have to develop this knowledge internally as the legacy technologies are often quite unique and often not part of post-secondary education programs. It is clear that the sector is evolving using a mix of old, new and updated infrastructure and equipment and traditional and non-traditional sources of electricity. For power producers including both private and public, this means new skill sets and knowledge bases at all levels of the business to support changing operations and business requirements.

THE NEED FOR SPECIALIZED KNOWLEDGE

It is widely known that the majority of positions in the sector require some form of post-secondary education and that these workers will need to become lifelong learners. The competencies and skills required are constantly being upgraded by new technology, regulations and management systems that become available. Results from the ESC 2008 Labour Market Information (LMI) Study indicate that employers are increasingly in need of employees who have a broader base of knowledge in computing/ technology and are able and willing to commit to lifelong learning. Employers also want graduates with ‘essential skills’, such as communication and people skills, and math skills. More than ever tradespeople will be required to have the skills and training in new and advanced technologies. These changes are happening swiftly and Power Line and Cable Workers, Power System Operators, and other trades people are increasingly required to have a changed skill set which better reflects the demands of the electricity sector today.

CHANGING DEMOGRAPHICS – THE AGING WORKFORCE AND KNOWLEDGE TRANSFER

Recent studies conducted by the ESC, augmented by several other labour market studies[13], anticipate profound changes to the sector’s workforce over the next few years. The portion of the population aged 55 and older increased from just over 15% in 1971 to approximately 20% by the end of 1991 and it has risen to approximately 25% today, with a further projected increase to 30% by 2016.[14]

This change in demographics, coupled with slowing growth in the population due to declining fertility rates, have resulted in a declining growth rate in the working age population,[15] which, in turn, is predicted by some

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[12] Refer to the US coal industry study in Part B to this Toolkit - Best Practices for information about how one sub sector is currently dealing with the challenge of accelerated learning.
[13] Conference Board of Canada; Ontario Chamber of Commerce
[14] (1976 – 2005) Statistics Canada Annual Demographic Statistics, (2006 – 2051) HRSDC - SPRD, Labour Market and Skills Forecasting and Analysis Unit, 2006 Reference Scenario
[15] Statistics Canada (2005) Population Projections for Canada, Provinces and Territories 2005-2031. Catalogue No. 91-520-XIE. (December) at p. 1

observers to adversely affect Canada's productivity growth[16]. As for the electricity sector, data based on reporting by employers estimates that approximately 30% of the current electricity workforce are expected to retire between 2007 and 2012. This has serious implications for both maintaining and sustaining the skilled workforce within the sector.

Under current trends, the 2008 ESC LMI Study predicts there will be an insufficient supply of workers to fill the demand of the sector to meet the growing consumer demand for electricity. This gap exists at all levels of the industry, from engineers, through technicians and trades people. This means that the sector will have to double its hiring of recent post-secondary graduates at a time when the demand for such workers is increasing in many other sectors as well.

> "Some technical jobs are difficult to recruit, primarily because of the specialized knowledge and new technical requirements that continue to expand. Utility companies are all competing for the same relatively small labour pool".
>
> *Northeastern Utilities*

Even if companies can hire the required employees, younger workers cannot be counted on to fill the void, as they lack the depth of experience that is required in the sector.[17] In addition, younger workers today tend to be more highly mobile and change jobs frequently, taking their technological savvy and any knowledge they have gained with them. Conventional expectations that knowledge will simply pass down through long tenured employees simply no longer holds true. The mobility and lack of loyalty of the modern workforce, and the fact that in many workplaces, as many as four generations work side-by-side, means knowledge is not always filtered well throughout the organization.[18]

Existing staff need development so that they are ready to fill vacancies in senior and critical specialist/ technical positions that require significant experience in the field. New workers require orientation and training to bring them to a competent level of performance, particularly in heavily regulated industries such as the electricity sector. Sector participants generally note that new engineering and technical graduates require four years of on-the-job experience to reach full competency. Managers, usually with engineering backgrounds, generally require 10 to 12 years of experience in the field, which is why management retirements are a particularly worrying issue for the industry. This is leading to an emerging critical situation whereby remaining employees are leaving (retiring) and there is an insufficient pool of well-trained and experienced employees ready to take their place. The situation is even more serious since the sector is growing, particularly in the newer electricity sub-sectors, and employers not only need to replace retiring workers, but require additional workers with new skills and competencies to sustain business growth.

DEVELOPING THE NEXT GENERATION OF ELECTRICITY WORKERS & POST-SECONDARY EDUCATION

The sector needs to invest substantially in human capital development. In some areas of the industry, workers (such as engineers, specialized technicians and management) typically have a life-long career in the electricity sector, and these workers possess a tremendous amount of corporate memory and experience. Sector workers have, on average, a higher level of education than workers in other industries. Specifically, 76% of electricity workers have a certificate, degree or post-secondary degree, compared to 57% for all industries. This is positive since globally all labour experts predict that employees in the future, whatever the sector, will be required to have some form of post-secondary education. Having a skilled and trained workforce means that industry organizations within the sector will be competing aggressively with each other to recruit and retain many of these graduates.

Within this backdrop, the sector has faced an "image" problem a result of cyclical downturns in the sector that led to slow downs and a lack of demand for labour and subsequent declines in enrolment in electrical

[16] OECD (Organization for Economic Co-operation and Development) (2005a), Aging and Employment Policies: Canada, Paris: OECD.
[17] Greenes, K. & Piktialis, D. (2008a) Bridging the Gaps: How to Transfer Knowledge in Today's Multigenerational Workplace
[18] Retrieved from: http://www.management-issues.com/2008/8/27/research/organisations-ignoring-the-transfer-of-knowledge.asp

engineering programs, except in British Columbia. This may be changing with the predicted rise in demand for electricity and a greater interest in greener/renewable sources of electricity including: solar, geothermal, wind and tidal power. However, even with a changed image, there is an issue with the number and calibre of graduates ready to work in the sector. In recent years, universities have not invested in electricity-related programming and faculty are reaching retirement ages. In some cases positions are not being replaced with academic experts in the electricity sector. Many national and international sector councils within broader energy industries have noted that the number of engineering graduates has been declining, particularly in the nuclear and electrical fields, which in turn has been compounded by the fact that the engineering faculty in these disciplines are also of a retirement age and are not being replaced. This means that there are not enough universities offering electricity-related specialized programs since the numbers of professors in these fields are also declining and not being replaced. In turn the programs are not being sufficiently updated and fuelled by new academic research. The US, the UK as well as the Nuclear, Solar and Wind sectors are actively working through their respective international sector councils with governments, educational institutions and other stakeholders to remedy this issue.

The approach to developing workers in the sector is also changing. According to the International Atomic Energy Agency (IAEA), traditional worker training programs have addressed explicit knowledge that is contained in written documents, policies, and procedures. However, tacit knowledge that is held in a person's mind has not typically been either captured or transferred in any formal manner. Rather, new workers have acquired such knowledge over time (if at all) through working with those who already possess it. As those workers, who are in possession of this tacit knowledge, leave the workplace for retirement, the effective capture and transfer of that information becomes even more critical.[19]

Although this need has always existed as individuals transferred to other jobs or leave the organization, there have usually been others in the organization that also had the tacit knowledge to provide continuity of operation. It is the increased rate of current and expected worker departures, along with the decreasing numbers of qualified replacements that has made KT a more significant problem.

The potential risks associated with impending demographic shifts, emerging and legacy technologies, potential economic downturns, increasing competition and, in some cases, a mismatch within the sector between the supply and demand of employees with the right skills and expertise include an increasing lack of knowledge to maintain legacy systems and/or have and apply sophisticated technology skills at all levels of the workforce (from power line workers to electrical engineers). There is also the potential for a decrease in innovation and productivity due to critical gaps in the workforce, a lower level of skills, knowledge and expertise, which could lead to an increase in health and safety incidents, both on the job, for the sector and for the Canadian public.

Clearly the sector is diverse with different life cycles and approaches to harnessing and distributing electricity using a variety of technologies and systems - some legacy and others leading edge. The business drivers and needs of organizations within each sub-sector will vary as will the solutions to KM/KT issues.

[19] International Atomic Energy Agency (IAEA). "The Nuclear Power Industry's Aging Workforce, Transfer of Knowledge to the Next Generation", in the June 2004 Journal of Knowledge Management Practice.

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APPENDIX 4B – 2011 MANAGEMENT SALARY SURVEY REPORT

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The MEARIE Group - 3700 Steeles Ave West, Suite 1100, Vaughan, Ontario, L4L 8K8

2011/2012 Management Salary Survey

Survey of Ontario’s Local Distribution Companies

Survey Overview

We are pleased to provide you with a copy of The MEARIE Group's 2011/2012 ***Management Salary Survey of Ontario's Local Distribution Companies***. We had the best participation in the last decade this year, with a total of 47 utilities participating in the survey. This helps to make the data more robust for all users.

We provided the survey in a web-based format which was available to all LDCs. This is also the second time we have offered the Board of Directors Compensation Survey as an adjunct to the main survey. The surveys are compiled by a third party provider, Cyr & Associates Inc., to ensure confidentiality and consistency of the information. The consolidated results are compiled and provided to The MEARIE Group for distribution and printing.

We added two new positions this year, based on feedback from participants. The new positions are: Billing Supervisor and Conservation and Demand Management Officer. We have also made some minor changes to the groupings of utilities in sections of Employee Size and Customer Size, to better reflect changes and growth within some of the utitlities.

Portions of the data have been marked with an asterisk* where responses were insufficient to report. Not every utility provides complete data for all positions. In some cases, the data isn't available or it is not applicable at that utility. In these cases, the data is marked with an asterisk.

The report has been divided into the following sections:

- All LDCs consolidated
- By Customer Size (electrical metered customers only)
- Revenue Grouping – all gross revenues including the cost of power
- By District
- By Employee Size

Reporting in this manner allows a complete representation of data to better assist you with your compensation and organisational planning. In the interests of continually striving to serve you better, please forward any suggestions or comments on this survey to - Connie McLaren, Sales and Marketing Manager, H.R. and Business Services at cmclaren@mearie.ca or by contacting her directly at The MEARIE Group's offices (905) 265-5327.

We are always looking for your suggestions on any positions or changes that you feel should be included in the survey to better serve you. Remember, positions have to be commonly represented across the utilities to be included in the survey.

Table of Contents:

Participant List (Alphabetical Order)

Local Distribution Company	District	Customer Size	Employee Base
Bluewater Power Distribution	WE - Western	35,704	118
Brant County Power Inc.	NG - Niagara Grand	9,645	29
Burlington Hydro Inc.	UC - Upper Canada	65,000	94
Chatham-Kent Energy	WE - Western	32,645	81
City of Brantford (Brantford Power)	NG - Niagara Grand	38,159	84
Collingwood Utility Services	GB - Georgian Bay	15,430	46
Enwin Utilities Ltd.	WE - Western	86,428	192
Erie Thames Powerlines	NE - Northeastern	14,376	37
Essex Power Corporation	WE - Western	28,270	57
Festival Hydro Inc	NG - Niagara Grand	19,750	45
Fort Frances Power Corporation	NW - Northwestern	3,770	9
Greater Sudbury Utilities	NE - Northeastern	47,500	112
Grimsby Power Incorporated	NG - Niagara Grand	10,231	17
Guelph Hydro Electric Systems Inc.	NG - Niagara Grand	50,250	99
Haldimand County Hydro Inc.	NG - Niagara Grand	20,972	48
Hydro Ottawa Group of Companies	NE - Northeastern	302,306	550
Innisfil Hydro Distribution Systems Ltd	GB - Georgian Bay	14,797	32
Kenora Hydro Electric Corporation Ltd	NW - Northwestern	5,600	16
Kitchener-Wilmot Hydro Inc.	NG - Niagara Grand	86,939	172
Lakeland Holding Ltd	GB - Georgian Bay	9,532	35
London Hydro Inc.	WE - Western	149,200	307
Midland Power Utility Corporation	GB - Georgian Bay	6,900	15
Milton Hydro Distribution Inc	UC - Upper Canada	29,789	45
Newmarket-Tay Power Distribution Ltd.	NE - Northeastern	31,000	52
Niagara Peninsula Energy	NG - Niagara Grand	51,048	113
Niagara-on-the-Lake Hydro Inc.	NG - Niagara Grand	7,882	18
Norfolk Power Distribution Inc.	NG - Niagara Grand	19,058	47
North Bay Hydro	NE - Northeastern	23,000	46
Northern Ontario Wires Inc.	NE - Northeastern	6,100	14
Orangeville Hydro	GB - Georgian Bay	11,347	20
Orillia Power Corporation	GB - Georgian Bay	12,900	46
Oshawa PUC Networks, Inc.	UC - Upper Canada	55,000	64
Ottawa River Power Corporation	UC - Upper Canada	10,518	28
Peterborough Utilities	NE - Northeastern	35,000	158
PowerStream	UC - Upper Canada	330,000	450
PUC Services Inc.	NE - Northeastern	33,000	180
Sioux Lookout Hydro Inc.	NW - Northwestern	2,750	8
St. Thomas Energy Services Inc.	WE - Western	16,420	35
Thunder Bay Hydro	NW - Northwestern	49,587	123
Utilities Kingston	UC - Upper Canada	26,940	378

Participant List (Alphabetical Order)

Local Distribution Company	District	Customer Size	Employee Base
Veridian	NE - Northeastern	112,915	217
Wasaga Distribution Inc.	GB - Georgian Bay	12,095	19
Waterloo North Hydro Inc.	NG - Niagara Grand	51,934	116
Welland Hydro-Electric System Corp.	NG - Niagara Grand	22,000	39
Westario Power Inc.	GB - Georgian Bay	22,007	35
Whitby Hydro	UC - Upper Canada	40,000	66
Woodstock Hydro Services Inc.	WE - Western	15,000	37

Using the Survey Results

The 2011/2012 Management Salary Survey for Ontario LDCs represents data submitted by 47 organizations covering approximately 4549 incumbents in 37 different executive, managerial, professional and administrative positions. All salary data is based on rates effective June 1st, 2011. We reserve the right to exclude data which is considered statistically invalid or incorrect and have contacted individual participants for clarification in some instances. Where job matches were clearly incorrect or single incumbent jobs were reported in several positions, data may have been modified to correct the entry.

Salary surveys can be a tremendously valuable tool to assist you in your workforce planning, salary administration and budgeting. However, results can vary from year to year depending upon the number of participants in the survey and the data provided.

Keep in mind that compensation surveys can only reflect 'benchmark' positions. **Benchmark** positions are those jobs that are commonly found across the industry, where primary responsibilities and incumbent requirements are consistent for approximately 80% of the primary responsibilities. You should also be sensitive to variables in jobs that are affected by the scope of the role, location or size of organization.

Generally, if you can match 40% to 50% of your key jobs to external data – such as this report, you will have a strong basis on which to plan your compensation program. When using the data, match your jobs to the survey based on job content and not the job title. Other unique positions do not have significant enough representation to provide accurate compensation data. Please note the following:

To preserve the confidentiality of data supplied by participating organizations, compensation data is reported only where a minimum of three organizations and three incumbents are included in the sample. Compensation medians, P25 and P75 for actual salaries are reported only where there is a minimum of four organizations and four incumbents included in the data. Where there was insufficient data, information was not reported.

Survey Definitions

# of Companies	The actual number of companies reporting information for the position.
# of Incumbents	The actual number of **incumbents in the role.**
Average Range Maximum	The average maximum rate of the salary ranges for all respondents.
Average Range Minimum	The average minimum rate of the salary ranges for all respondents.
Bonus	An after-the-fact reward or payment based on the performance of an individual, a group of workers operating as a unit, a division or an entire work force.
Executive	The group of individuals who head major operating functions of the organization and typically report to the President/CEO.
Gainsharing	A bonus plan aimed at improving productivity or costs through improved work methods.
Gross Revenues	Total revenues from inflow of assets, including revenues from sales of products or services.
Average Incentive Maximum%	The maximum annual cash incentive for the job as a percentage of base salary.
Average Incentive Target %	The target annual cash incentive for the job as a percentage of base salary.
Individual Incentive	Any form of variable payment tied to performance. The payment is a monetary award. Incentives are contrasted with bonuses in that performance goals for incentives are predetermined.
Mean (Average Actual)	The sum of the actual average salary reported divided by the number of respondents.
Median (Median of the actual salaries reported).	Median is the middle rate when data are arranged in order and there is an odd number of observations (i.e. 3, 5, 7 etc.). It is the mean of the two middle observations when the data is arranged in order for even number observations (2, 10 etc.); most compensation professionals prefer to make comparisons on this basis since it is less easily influenced by extreme values.
Middle Management	The group of managers and/or professionals directly reporting to the Executive.
P25 (25th percentile of actual salaries reported)	25th Percentile (1st Quartile) – The rate within the sample of actual reported base salaries which is higher than 25% of all rates reported.
P75 (75th percentile of actual salaries reported)	75th Percentile (3rd Quartile) – The rate within the sample of actual reported base salaries which is higher than 75% of all rates reported.
Profit Sharing	An automatic fixed percentage of total profits or of profits above a certain threshold awarded to employees strictly on the performance of the entire organization.
Team Based Incentive	A specified project or operational team may receive an incentive based upon results, deliverables or an increase in productivity.
Variable Pay	Compensation that is contingent on discretion, performance or results achieved. It may be referred to as pay at risk.

Compensation Analysis: <u>All Local Distribution Companies</u>

Table 1: Annual Salaries – All LDCs

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	47	40	$130,701	$171,856	$160,573	$138,000	$181,200	$155,197	19	25
V.P. Operations & Engineering/COO	47	23	$115,365	$148,286	$140,616	$121,161	$149,959	$135,000	16	21
Director/V.P. Operations	47	16	$108,531	$134,429	$127,074	$112,770	$134,213	$128,454	12	15
Director/V.P. Engineering	47	13	$110,286	$134,240	$124,370	$113,547	$132,120	$124,110	12	18
Engineering Manager	47	26	$86,496	$109,348	$102,631	$95,431	$109,361	$104,428	7	10
Distribution Engineer	47	19	$77,265	$103,602	$92,923	$86,896	$100,271	$91,305	5	8
Engineering Supervisor	47	25	$72,961	$95,523	$88,870	$83,371	$93,832	$87,568	5	9
Operations Manager or Superintendent	47	43	$83,198	$105,865	$98,123	$92,739	$101,299	$97,900	5	10
Control Centre Supervisor	47	17	$79,603	$99,408	$94,580	$89,777	$100,555	$92,438	6	10
Meter Shop Supervisor	47	23	$76,032	$94,715	$90,252	$85,425	$95,878	$90,230	6	8
Line Supervisor	47	91	$74,896	$94,642	$88,657	$84,838	$90,721	$88,169	6	10
Purchasing/Procurement Manager	47	19	$74,468	$95,035	$87,182	$78,649	$96,423	$85,051	7	11
Stores/Inventory Control Supervisor	47	10	$65,482	$82,358	$81,849	$78,998	$91,021	$79,552	8	8
Executive Assistant (to President)	47	33	$56,830	$71,145	$67,550	$63,168	$72,629	$66,631	5	8
Administrative Assistant	47	40	$49,603	$61,385	$58,353	$54,166	$63,150	$59,535	6	7
Director/VP Finance/CFO	47	37	$109,196	$141,457	$131,626	$109,273	$141,370	$130,816	14	22
Controller/Manager Finance	47	25	$86,535	$110,417	$100,353	$91,519	$106,161	$97,448	8	12
General Accounting Manager	47	14	$78,565	$100,891	$92,399	$83,563	$97,516	$91,783	7	12
Accounting Supervisor	47	21	$66,912	$85,518	$79,820	$72,990	$84,686	$80,470	8	9
Billing Supervisor	47	18	$67,697	$85,036	$79,553	$75,168	$82,937	$79,552	7	10
Director or VP, Customer Service	47	16	$96,884	$126,227	$119,488	$106,534	$128,091	$113,050	11	15
Manager, Customer Service	47	20	$78,924	$103,224	$93,455	$87,467	$102,964	$91,416	7	11
Customer Service Supervisor	47	30	$63,778	$81,661	$74,532	$69,137	$81,454	$75,611	6	8
Financial/Business Analyst	47	35	$63,778	$81,661	$75,777	$70,703	$82,090	$76,491	6	9
Director or VP, Regulatory Affairs	47	10	$107,397	$143,828	$131,861	$122,981	$135,325	$129,246	14	20
Manager, Regulatory Affairs	47	19	$71,257	$94,672	$86,207	$76,608	$91,748	$82,775	5	9

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	47	18	$66,859	$81,102	$77,269	$69,617	$82,371	$72,916	6	7
Conservation & DM Officer	47	21	$69,106	$85,437	$77,501	$68,959	$86,236	$79,854	7	9
I.S. Director/VP	47	11	$105,297	$135,502	$129,327	$118,512	$133,258	$121,055	13	19
I.S. Manager	47	18	$76,923	$100,343	$92,605	$83,165	$102,402	$89,150	9	13
I.S. Supervisor/Computer Operations	47	9	$74,688	$98,776	$87,926	$81,167	$95,159	$89,337	5	8
Systems Administrator/Apps Support	47	33	$62,730	$80,590	$76,554	$70,562	$82,306	$79,166	5	8
Human Resources Director/VP	47	11	$106,192	$125,031	$126,208	$107,487	$136,732	$127,182	15	19
Human Resources Manager	47	14	$80,533	$105,896	$94,879	$84,348	$103,509	$91,332	8	14
Human Resources Generalist/Officer	47	18	$62,052	$81,596	$74,453	$66,731	$78,442	$73,930	8	8
Human Resources Assistant/Coord.	47	16	$51,512	$65,185	$59,684	$58,512	$64,168	$61,402	6	7
Manager Health & Safety/Loss Control	47	20	$76,775	$96,828	$91,370	$85,981	$97,041	$90,667	8	12

Compensation Analysis: By Customer Size

Table 2: Customer Size – LDCs (1 to 10,000 Customers)

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	8	8	98,496	122,100	115,292	106,540	118,436	114,202	*	*
V.P. Operations & Engineering/COO	*	*	*	*	*	*	*	*	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	*	*	*	*	*	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	8	6	*	*	90,948	88,523	96,574	91,273	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	*	*	*	*	*	*	*	*	*
Line Supervisor	8	3	*	*	84,677	*	*	*	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	*	*	*	*	*	*	*	*	*	*
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	8	5	*	*	95,653	86,990	98,318	89,105	*	*
Controller/Manager Finance	8	3	*	*	78,608	*	*	*	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	*	*	*	*	*	*	*	*	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Customer Size
Table 3: Customer Size – LDCs (10,001 to 20,000 Customers)

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	12	11	126,557	160,653	147,731	134,664	151,450	139,435	*	*
V.P. Operations & Engineering/COO	12	4	106,303	128,161	120,620	110,012	128,573	117,965	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	12	6	79,904	99,977	92,792	89,146	99,152	90,500	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	12	7	81,606	105,111	97,664	96,036	99,878	98,340	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	12	3	74,929	92,476	89,007	*	*	*	*	*
Line Supervisor	12	8	74,301	95,186	86,178	84,524	87,720	86,623	*	*
Purchasing/Procurement Manager	12	3	63,020	83,399	76,676	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	12	5	*	*	61,362	57,350	64,900	63,220	*	*
Administrative Assistant	12	3	47,339	56,755	54,040	*	*	*	*	*
Director/VP Finance/CFO	12	8	98,197	126,169	114,797	105,137	130,740	109,697	*	*
Controller/Manager Finance	12	5	85,896	102,358	95,317	94,370	99,152	98,492	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	12	3	62,162	87,952	76,309	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	12	3	*	*	91,322	*	*	*	*	*
Customer Service Supervisor	12	3	*	*	67,841	*	*	*	*	*
Financial/Business Analyst	12	5	61,419	80,938	75,020	68,581	79,310	72,870	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	12	3	69,224	91,274	82,484	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	12	3	52,264	78,325	60,740	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	12	3	*	*	84,360	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Customer Size
Table 4: Customer Size – LDCs (20,001 to 30,000 Customers)

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	7	6	123,803	158,893	155,345	150,931	156,764	155,598	13	20
V.P. Operations & Engineering/COO	*	*	*	*	*	*	*	*	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	*	4	87,098	112,665	102,421	95,431	104,140	97,149	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	3	70,018	88,561	*	*	*	*	*	*
Operations Manager or Superintendent	*	5	81,906	105,682	95,950	87,006	94,870	90,359	6	7
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	3	75,369	93,664	89,269	*	*	*	*	*
Line Supervisor	*	11	74,630	95,553	89,023	84,517	92,644	84,838	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	*	6	55,908	69,614	69,872	67,906	72,788	71,775	*	*
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	*	6	100,112	124,715	120,113	108,654	114,777	112,429	7	10
Controller/Manager Finance	*	*	*	*	*	*	*	*	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	3	*	*	76,919	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	*	4	60,673	74,550	69,670	61,577	76,579	68,486	*	*
Financial/Business Analyst	*	8	61,640	78,586	71,148	62,505	78,550	68,297	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	3	64,664	79,833	73,740	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	3	67,114	84,432	75,831	*	*	*	*	*
Conservation & DM Officer	*	3	*	*	64,565	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	3	67,482	88,958	74,831	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	10	60,052	74,943	68,026	62,557	73,093	72,831	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Customer Size
Table 5: Customer Size – LDCs (30,001 to 40,000 Customers)

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	7	6	144,263	185,639	181,462	163,145	194,206	181,200	19	19
V.P. Operations & Engineering/COO	*	5	109,250	136,875	132,485	128,041	133,397	131,943	*	*
Director/V.P. Operations	*	5	96,276	115,154	113,565	106,200	115,465	107,212	*	*
Director/V.P. Engineering	*	3	*	116,852	116,852	*	*	*	*	*
Engineering Manager	*	3	88,160	111,423	109,329	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	4	80,099	100,437	95,266	87,629	95,597	87,959	*	*
Operations Manager or Superintendent	*	6	82,025	100,719	99,559	93,433	101,661	96,635	4	4
Control Centre Supervisor	*	3	*	99,932	99,932	*	*	*	*	*
Meter Shop Supervisor	*	4	73,925	93,593	92,535	89,541	95,227	92,232	*	*
Line Supervisor	*	11	71,872	88,703	86,961	84,628	89,683	86,285	4	4
Purchasing/Procurement Manager	*	3	71,525	88,641	86,262	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	*	7	54,338	66,699	65,840	63,231	68,173	64,963	4	4
Administrative Assistant	*	7	45,874	54,898	54,403	56,180	59,096	56,303	*	*
Director/VP Finance/CFO	*	7	285,632	136,446	136,669	131,380	141,051	133,397	10	10
Controller/Manager Finance	*	5	70,705	95,295	93,060	89,747	98,687	95,374	4	4
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	4	92,278	117,416	113,096	105,673	117,679	110,256	*	*
Manager, Customer Service	*	5	75,040	98,245	97,186	89,150	102,402	99,346	4	4
Customer Service Supervisor	*	5	58,420	79,555	80,147	78,300	82,078	80,231	4	4
Financial/Business Analyst	*	6	61,837	77,144	74,807	72,467	81,772	76,491	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	6	68,779	90,390	87,099	81,053	90,854	88,530	4	4

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	5	70,298	88,433	86,362	*	*	*	*	*
Conservation & DM Officer	*	5	58,206	64,669	67,706	60,000	79,854	68,959	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	5	71,225	94,865	91,466	83,165	102,402	89,150	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	7	58,360	75,655	80,673	76,983	83,508	79,818	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	4	59,869	74,754	73,063	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	4	71,753	88,257	85,555	80,084	88,811	83,340	*	*

Compensation Analysis: By Customer Size
Table 6: Customer Size – LDCs (40,001-80,000 Customers)

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	7	5	144,579	186,186	175,539	161,790	179,495	174,900	*	*
V.P. Operations & Engineering/COO	*	5	128,949	158,910	143,035	139,564	146,914	140,692	12	16
Director/V.P. Operations	*	3	111,126	125,191	125,192	*	*	*	*	*
Director/V.P. Engineering	*	3	115,460	129,525	128,071	*	*	*	*	*
Engineering Manager	*	5	87,444	111,748	105,975	103,070	109,089	107,627	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	7	69,790	100,013	89,777	86,272	94,035	90,529	*	*
Operations Manager or Superintendent	*	8	86,727	110,008	101,762	98,239	106,123	100,531	5	7
Control Centre Supervisor	*	5	76,519	99,614	92,799	90,002	97,365	91,360	*	*
Meter Shop Supervisor	*	5	76,350	97,266	88,483	86,398	90,230	90,002	*	*
Line Supervisor	*	21	74,993	96,254	90,260	89,125	90,222	89,460	5	7
Purchasing/Procurement Manager	*	5	72,921	92,624	85,059	81,439	86,113	84,348	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	*	8	56,003	68,949	69,526	65,212	72,629	68,500	4	5
Administrative Assistant	*	7	47,095	60,940	58,616	*	*	*	*	*
Director/VP Finance/CFO	*	5	116,901	151,377	145,080	133,935	141,370	139,254	*	*
Controller/Manager Finance	*	5	83,930	104,376	100,410	95,244	105,096	99,930	*	*
General Accounting Manager	*	3	83,045	112,008	101,432	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	6	67,842	85,768	77,753	73,930	81,496	74,911	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	*	4	79,336	106,205	94,198	89,598	99,190	94,591	5	8
Customer Service Supervisor	*	6	67,000	82,218	74,678	70,712	81,930	71,989	*	*
Financial/Business Analyst	*	4	67,970	86,783	77,112	75,433	79,605	77,926	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	3	76,437	104,403	94,765	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	3	63,967	*	73,835	*	*	*	*	*
Conservation & DM Officer	*	4	71,149	85,522	85,522	81,744	89,173	85,394	*	*
I.S. Director/VP	*	3	100,922	124,316	117,342	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	3	77,073	*	92,015	*	*	*	*	*
Systems Administrator/Apps Support	*	5	68,284	84,037	83,747	79,561	85,879	81,693	*	*
Human Resources Director/VP	*	3	*	*	130,645	*	*	*	*	*
Human Resources Manager	*	4	81,803	105,518	94,995	88,587	101,880	95,472	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	6	74,754	90,150	88,454	88,067	95,412	91,746	*	*

Compensation Analysis: By Customer Size
Table 7: Customer Size – LDCs (80,001 to 120,000 Customers)

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	*	*	*	*	*	*	*	*	*	*
V.P. Operations & Engineering/COO	*	*	*	*	*	*	*	*	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	3	4	95,054	114,097	105,688	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	*	*	*	*	*	*	*	*	*	*
Control Centre Supervisor	3	3	81,250	92,762	86,837	*	*	*	*	*
Meter Shop Supervisor	3	3	80,198	88,771	88,772	*	*	*	*	*
Line Supervisor	3	15	80,198	91,470	88,814	*	*	*	*	*
Purchasing/Procurement Manager	3	3	86,162	104,459	100,103	*	*	*	*	*
Stores/Inventory Control Supervisor	3	3	69,034	81,188	81,188	*	*	*	*	*
Executive Assistant (to President)	3	3	67,722	78,534	78,548	*	*	*	*	*
Administrative Assistant	3	6	60,224	69,729	65,305	*	*	*	*	*
Director/VP Finance/CFO	3	3	128,114	164,681	156,153	*	*	*	*	*
Controller/Manager Finance	*	*	*	*	*	*	*	*	*	*
General Accounting Manager	3	3	83,705	101,583	91,126	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	3	3	*	135,188	130,165	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	3	4	70,275	81,654	80,709	*	*	*	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	3	4	65,162	75,904	74,489	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	3	3	101,989	123,942	119,519	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	3	3	82,227	95,579	95,579	*	*	*	*	*

Compensation Analysis: By Customer Size
Table 8: Customer Size – LDCs (120,001+ Customers)

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	3	*	*	*	*	*	*	*	*	*
V.P. Operations & Engineering/COO	3	3	135,243	196,860	192,733	*	*	*	25	33
Director/V.P. Operations	3	3	114,704	157,959	149,273	*	*	*	*	*
Director/V.P. Engineering	3	3	112,266	152,139	141,461	*	*	*	*	*
Engineering Manager	3	4	88,741	118,503	110,396	*	*	*	*	*
Distribution Engineer	3	10	82,224	109,085	102,706	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	3	8	85,885	114,940	105,558	*	*	*	*	*
Control Centre Supervisor	3	4	76,882	102,401	99,095	*	*	*	*	*
Meter Shop Supervisor	3	5	75,912	101,195	93,863	*	*	*	*	*
Line Supervisor	3	22	77,839	103,608	97,894	*	*	*	*	*
Purchasing/Procurement Manager	3	3	81,045	108,894	101,327	*	*	*	*	*
Stores/Inventory Control Supervisor	3	4	66,598	88,509	87,707	*	*	*	*	*
Executive Assistant (to President)	3	3	54,845	72,952	66,434	*	*	*	*	*
Administrative Assistant	3	15	52,508	70,030	63,653	*	*	*	*	*
Director/VP Finance/CFO	3	3	*	*	200,769	*	*	*	27	36
Controller/Manager Finance	3	3	98,705	136,396	126,267	*	*	*	*	*
General Accounting Manager	3	3	78,589	106,504	98,759	*	*	*	*	*
Accounting Supervisor	3	8	66,865	88,835	84,848	*	*	*	*	*
Billing Supervisor	3	5	67,561	89,709	84,459	*	*	*	*	*
Director or VP, Customer Service	3	3	103,793	143,644	134,577	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	3	6	66,598	88,509	82,325	*	*	*	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	3	3	108,585	150,233	138,604	*	*	*	*	*
Manager, Regulatory Affairs	3	3	82,873	111,174	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	3	3	79,974	107,541	99,974	*	*	*	*	*
I.S. Director/VP	3	3	113,633	163,014	153,461	*	*	*	*	*
I.S. Manager	3	3	96,340	129,477	119,265	*	*	*	*	*
I.S. Supervisor/Computer Operations	3	4	75,637	100,855	89,954	*	*	*	*	*
Systems Administrator/Apps Support	3	6	69,510	92,142	89,341	*	*	*	*	*
Human Resources Director/VP	3	3	105,160	151,821	141,996	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	3	7	54,366	72,353	66,553	*	*	*	*	*
Manager Health & Safety/Loss Control	3	5	87,012	117,828	102,718	*	*	*	*	*

Compensation Analysis: By Gross Revenue Grouping

Table 9: LDCs Gross Revenue Under $20 Million

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	11	10	105,166	147,928	122,608	113,161	122,720	116,163	*	*
V.P. Operations & Engineering/COO	*	*	*	*	*	*	*	*	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	11	3	85,921	106,353	*	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	11	7	80,433	107,265	94,002	91,273	99,476	95,000	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	*	*	*	*	*	*	*	*	*
Line Supervisor	11	6	68,263	96,179	84,995	82,671	86,506	85,688	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	11	5*	*	*	59,329	53,055	64,900	57,350	*	*
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	11	6	90,261	126,475	104,510	88,042	121,330	93,712	*	*
Controller/Manager Finance	11	4	84,351	*	89,975	85,259	92,378	87,663	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	11	4	*	*	77,720	63,614	90,465	76,360	*	*
Customer Service Supervisor	11	4	*	*	66,303	59,768	74,031	67,496	*	*
Financial/Business Analyst	11	3	56,844	79,533	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Gross Revenue Grouping

Table 10: LDCs Gross Revenue $20,000,001 to $50,000,000 Million

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	10	10	135,579	158,736	149,351	139,854	154,547	145,900	*	*
V.P. Operations & Engineering/COO	10	5	95,763	114,474	114,318	110,849	118,450	115,000	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	10	3	76,454	94,441	92,933	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	10	6	76,203	93,761	93,541	88,660	98,230	94,200	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	*	*	*	*	*	*	*	*	*
Line Supervisor	10	9	74,611	88,674	86,046	84,419	87,870	86,546	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	10	3	*	*	68,365	*	*	*	*	*
Administrative Assistant	10	3	47,339	56,755	54,040	*	*	*	*	*
Director/VP Finance/CFO	10	8	99,418	118,155	110,319	105,137	115,296	109,060	*	*
Controller/Manager Finance	10	4	*	*	88,129	85,903	98,657	96,431	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	10	3	*	*	78,227	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	10	3	*	*	104,681	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	*	*	*	*	*	*	*	*	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	10	3	*	*	63,588	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	10	3	*	*	84,360	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Gross Revenue Grouping

Table 11: LDCs Gross Revenue $50,000,001 to $100,000,000 Million

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	10	8	120,830	161,795	161,131	149,509	161,510	155,824	13	15
V.P. Operations & Engineering/COO	10	5	113,581	136,967	135,300	131,943	139,564	133,397	*	*
Director/V.P. Operations	10	4	97,681	117,018	108,300	*	*	*	*	*
Director/V.P. Engineering	10	4	104,788	123,432	122,014	113,499	129,994	121,479	*	*
Engineering Manager	10	6	85,016	107,959	99,900	95,057	106,487	97,149	*	*
Distribution Engineer	10	4	71,899	100,203	90,089	*	*	*	*	*
Engineering Supervisor	10	4	74,742	98,491	96,444	87,104	101,243	91,904	*	*
Operations Manager or Superintendent	10	10	82,370	102,137	97,102	92,778	100,531	94,870	4	4
Control Centre Supervisor	10	3	*	94,626	94,626	*	*	*	*	*
Meter Shop Supervisor	10	6	73,773	91,157	88,960	83,626	91,833	90,306	*	*
Line Supervisor	10	16	73,621	92,496	88,065	84,638	90,780	88,002	*	*
Purchasing/Procurement Manager	10	3	72,045	88,021	85,800	*	*	*	*	*
Stores/Inventory Control Supervisor	10	3	60,815	77,377	76,651	*	*	*	*	*
Executive Assistant (to President)	10	8	54,289	66,426	66,087	63,085	71,049	64,592	*	*
Administrative Assistant	10	5	42,205	54,333	51,094	*	*	*	*	*
Director/VP Finance/CFO	10	9	228,792	129,947	129,942	114,955	133,935	131,943	5	5
Controller/Manager Finance	10	6	76,274	101,285	95,873	89,747	103,977	97,851	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	10	3	64,275	78,496	73,736	*	*	*	*	*
Director or VP, Customer Service	10	3	91,498	119,287	119,287	*	*	*	*	*
Manager, Customer Service	10	5	77,696	100,769	100,769	99,346	107,066	102,402	4	4
Customer Service Supervisor	10	7	60,772	76,958	74,756	68,819	80,892	75,000	*	*
Financial/Business Analyst	10	9	61,877	78,794	72,741	60,723	82,292	71,198	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	10	5	64,919	85,337	82,418	73,752	91,100	79,089	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	10	7	65,396	81,850	77,836	72,569	80,480	77,000	*	*
Conservation & DM Officer	10	6	59,868	73,065	66,144	54,330	78,835	66,965	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	10	7	72,647	94,444	89,316	81,170	101,467	88,551	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	10	7	59,196	75,223	72,849	71,828	78,833	75,000	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	10	3	59,722	76,113	69,562	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	10	3	73,690	91,996	88,513	*	*	*	*	*

Compensation Analysis: By Gross Revenue Grouping

Table 12: LDCs Gross Revenue $100,000,001 to $200,000,000 Million

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	11	9	148,012	191,802	182,385	174,900	183,860	181,200	17	20
V.P. Operations & Engineering/COO	11	6	123,651	157,931	137,697	129,781	145,359	137,846	14	17
Director/V.P. Operations	11	7	109,779	134,573	127,163	119,282	133,918	128,454	11	11
Director/V.P. Engineering	11	4	115,115	134,162	126,943	123,973	129,017	126,046	*	*
Engineering Manager	11	8	88,598	113,587	108,231	105,107	110,844	106,774	*	*
Distribution Engineer	11	4	77,913	97,781	86,280	*	*	*	*	*
Engineering Supervisor	11	10	72,487	94,837	85,496	82,563	87,674	87,178	4	7
Operations Manager or Superintendent	11	11	86,054	109,490	102,843	96,408	110,178	100,070	5	6
Control Centre Supervisor	11	6	79,714	100,818	94,122	86,583	99,549	94,363	*	*
Meter Shop Supervisor	11	8	76,968	96,729	90,711	86,382	95,125	88,535	*	*
Line Supervisor	11	32	75,929	95,892	89,790	85,987	90,681	89,460	5	6
Purchasing/Procurement Manager	11	8	72,499	92,407	86,001	83,434	89,423	85,582	4	6
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	11	12	56,566	70,551	69,875	65,675	72,978	71,647	4	4
Administrative Assistant	11	12	48,812	60,088	59,267	57,001	60,606	59,223	*	*
Director/VP Finance/CFO	11	9	110,425	142,798	137,247	130,625	141,370	139,254	11	14
Controller/Manager Finance	11	6	81,382	102,939	97,280	94,075	102,385	96,639	6	7
General Accounting Manager	11	6	76,998	99,644	91,186	83,563	98,744	89,234	5	5
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	11	7	68,308	87,632	80,953	76,071	85,204	80,524	4	5
Director or VP, Customer Service	11	5	95,733	117,146	112,119	107,212	114,915	113,300	*	*
Manager, Customer Service	11	5	78,474	103,265	93,188	89,150	97,370	91,811	5	7
Customer Service Supervisor	11	8	63,785	81,856	78,087	73,880	81,445	79,772	5	6
Financial/Business Analyst	11	10	65,952	83,156	75,128	71,581	78,830	76,491	4	5
Director or VP, Regulatory Affairs	11	3	102,087	143,290	131,426	*	*	*	*	*
Manager, Regulatory Affairs	11	7	72,503	96,328	88,003	80,493	91,039	86,946	5	6

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	11	5	68,161	82,759	79,690	70,012	84,261	79,552	5	5
Conservation & DM Officer	11	7	68,868	84,131	81,648	76,005	85,394	82,410	*	*
I.S. Director/VP	11	6	101,065	124,725	120,393	118,502	120,466	118,615	11	13
I.S. Manager	11	4	72,268	89,268	83,875	80,719	89,314	86,158	*	*
I.S. Supervisor/Computer Operations	11	3	77,073	*	92,015	*	*	*	*	*
Systems Administrator/Apps Support	11	16	63,803	81,034	82,203	76,192	87,463	81,081	4	4
Human Resources Director/VP	11	4	110,520	103,594	123,356	118,264	130,899	125,807	13	16
Human Resources Manager	11	5	79,557	101,971	94,262	90,000	100,944	91,332	6	7
Human Resources Generalist/Officer	11	5	56,888	73,082	66,413	64,343	68,801	66,731	*	*
Human Resources Assistant/Coord.	11	4	50,613	67,777	57,176	*	*	*	*	*
Manager Health & Safety/Loss Control	11	9	73,178	88,981	87,859	84,280	93,490	91,332	5	6

Compensation Analysis: By Gross Revenue Grouping

Table 13: LDCs Gross Revenue Over $200,000,001 Million

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	5	3	176,923	222,942	257,418	*	*	*	32	35
V.P. Operations & Engineering/COO	5	5	143,909	192,266	186,348	175,275	179,795	178,269	26	32
Director/V.P. Operations	5	4	115,888	154,964	145,133	132,263	147,888	135,019	15	22
Director/V.P. Engineering	5	4	109,580	145,125	132,971	112,035	145,759	124,824	15	20
Engineering Manager	5	7	91,279	115,820	107,083	107,827	115,339	108,022	10	14
Distribution Engineer	5	10	82,224	109,085	102,706	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	5	9	86,211	112,846	103,881	98,422	108,863	103,403	10	13
Control Centre Supervisor	5	6	77,915	98,914	94,595	89,100	98,469	93,516	10	12
Meter Shop Supervisor	5	7	77,458	96,612	92,213	85,425	98,521	95,878	8	9
Line Supervisor	5	28	78,615	99,678	95,165	92,248	97,136	96,260	10	12
Purchasing/Procurement Manager	5	5	84,374	108,079	100,926	93,500	111,583	107,147	11	14
Stores/Inventory Control Supervisor	5	6	68,650	85,908	85,427	78,998	92,030	91,021	7	9
Executive Assistant (to President)	5	5	61,954	76,412	72,509	64,750	80,995	71,541	8	9
Administrative Assistant	5	18	57,873	71,650	65,170	63,012	64,750	63,196	6	7
Director/VP Finance/CFO	5	5	149,476	199,215	191,170	175,275	202,044	178,269	28	34
Controller/Manager Finance	5	5	101,968	134,438	125,707	113,400	132,710	117,025	14	16
General Accounting Manager	5	5	81,426	104,920	96,980	90,100	98,521	94,500	12	13
Accounting Supervisor	5	12	68,810	86,103	82,619	72,990	85,560	84,686	7	9
Billing Supervisor	5	6	69,252	88,396	83,825	81,130	84,955	82,260	*	*
Director or VP, Customer Service	5	5	103,225	143,559	135,862	112,800	159,805	136,100	*	*
Manager, Customer Service	5	4	90,533	119,221	103,238	90,063	115,386	102,211	12	15
Customer Service Supervisor	5	9	69,394	86,188	81,910	78,118	84,457	81,875	8	9
Financial/Business Analyst	5	11	68,965	89,593	87,278	84,903	89,793	87,556	*	*
Director or VP, Regulatory Affairs	5	5	109,635	142,741	133,110	117,025	136,100	132,710	15	20
Manager, Regulatory Affairs	5	3	82,873	111,174	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	5	5	68,489	80,064	78,649	*	*	*	6	7
Conservation & DM Officer	5	4	85,361	111,677	103,181	96,774	112,950	106,544	10	11
I.S. Director/VP	5	5	110,376	148,434	140,048	132,710	150,416	133,806	17	22
I.S. Manager	5	5	94,052	123,749	113,669	105,331	119,185	110,848	13	18
I.S. Supervisor/Computer Operations	5	4	75,637	100,855	89,954	*	*	*	*	*
Systems Administrator/Apps Support	5	7	69,229	89,117	87,016	84,582	90,430	87,997	*	*
Human Resources Director/VP	5	5	105,292	141,718	133,169	107,827	152,891	132,710	17	22
Human Resources Manager	5	4	89,052	127,150	107,682	*	*	*	13	18
Human Resources Generalist/Officer	5	10	68,964	94,222	86,162	77,617	92,069	83,523	9	9
Human Resources Assistant/Coord.	5	9	55,355	68,976	64,271	61,402	66,540	61,973	5	7
Manager Health & Safety/Loss Control	5	7	86,831	109,644	100,578	89,897	107,147	97,758	11	15

Compensation Analysis: By District

Table 14: LDCs in District 'Georgian Bay'

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	8	7	135,579	163,562	149,469	136,219	153,150	141,500	*	*
V.P. Operations & Engineering/COO	8	3	*	*	113,650	*	*	*	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	8	3	83,824	98,158	96,650	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	8	6	78,878	94,041	93,681	88,660	98,230	94,200	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	*	*	*	*	*	*	*	*	*
Line Supervisor	8	5	*	*	85,692*	82,750	88,727	85,785	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	*	*	*	*	*	*	*	*	*	*
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	8	6	101,431	122,955	111,710	107,625	116,368	109,060	*	*
Controller/Manager Finance	8	4	*	*	88,580	85,903	99,439	96,761	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	*	*	*	*	*	*	*	*	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	8	3	*	*	84,360	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By District

Table 15: LDCs in District 'Northeastern'

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	9	8	135,002	183,728	166,645	153,901	176,675	163,742	22	22
V.P. Operations & Engineering/COO	9	6	115,823	159,835	151,118	135,221	170,330	143,603	20	24
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	9	7	88,175	115,986	107,053	100,702	115,810	110,178	9	10
Distribution Engineer	9	7	74,027	101,841	90,719	*	*	*	*	*
Engineering Supervisor	9	4	81,361	107,311	99,773	*	*	*	*	*
Operations Manager or Superintendent	9	11	85,566	112,241	100,073	96,329	108,512	100,930	7	8
Control Centre Supervisor	9	6	80,556	102,464	95,101	90,306	98,469	97,365	*	*
Meter Shop Supervisor	9	6	78,020	97,295	92,944	90,610	95,878	93,380	*	*
Line Supervisor	9	23	76,158	99,318	90,726	86,920	94,254	90,610	*	*
Purchasing/Procurement Manager	9	1	91,543	107,147	107,147	85,025	108,710	97,738	10	12
Stores/Inventory Control Supervisor	9	4	63,208	83,556	82,754	*	*	*	*	*
Executive Assistant (to President)	9	7	57,810	73,705	69,712	64,080	76,661	71,197	*	*
Administrative Assistant	9	16	51,996	66,400	63,113	59,719	63,859	61,919	*	*
Director/VP Finance/CFO	9	7	122,668	162,864	143,449	131,820	159,036	133,397	21	26
Controller/Manager Finance	9	8	82,612	111,390	102,365	97,970	111,050	102,402	9	10
General Accounting Manager	9	3	82,639	107,362	101,062	*	*	*	*	*
Accounting Supervisor	9	6	64,725	85,198	81,399	79,073	84,905	82,578	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	9	4	97,637	141,257	132,688	123,376	142,770	133,458	*	*
Manager, Customer Service	9	8	77,490	99,464	90,952	87,467	98,628	90,086	9	10
Customer Service Supervisor	9	5	65,330	85,426	81,698	80,350	82,521	81,173	*	*
Financial/Business Analyst	9	12	60,018	80,418	76,499	71,198	82,249	81,772	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	9	4	72,724	100,655	93,642	87,358	97,323	91,039	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	9	4	71,556	99,111	85,920	73,463	101,378	88,920	*	*
I.S. Director/VP	9	3	104,100	143,542	129,380	*	*	*	18	23
I.S. Manager	9	5	78,340	110,939	97,998	83,250	102,402	89,150	10	13
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	9	8	60,258	81,361	79,260	77,639	81,877	80,256	*	*
Human Resources Director/VP	9	3	96,814	98,362	124,492	*	*	*	18	23
Human Resources Manager	9	4	85,215	125,289	109,484	*	*	*	*	*
Human Resources Generalist/Officer	9	9	58,744	87,100	73,667	68,223	80,318	74,875	*	*
Human Resources Assistant/Coord.	9	7	52,976	69,005	60,226	*	*	*	*	*
Manager Health & Safety/Loss Control	9	4	89,467	117,555	106,855	101,144	110,485	104,775	13	17

Compensation Analysis: By District

Table 16: LDCs in District 'Niagara Grand'

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	12	11	122,637	149,771	144,879	127,938	158,807	142,538	*	*
V.P. Operations & Engineering/COO	12	5	114,134	126,867	123,785	119,790	131,943	125,080	*	*
Director/V.P. Operations	12	5	107,966	127,823	122,920	115,465	128,454	123,560	*	*
Director/V.P. Engineering	12	6	110,566	130,423	118,723	117,489	127,014	123,835	*	*
Engineering Manager	12	4	85,029	102,719	98,911	92,368	105,513	98,970	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	12	6	72,930	93,128	87,985	86,362	89,477	87,854	*	*
Operations Manager or Superintendent	12	10	83,100	104,621	98,154	94,968	99,008	96,740	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	12	8	73,766	91,099	86,671	81,065	90,733	86,619	*	*
Line Supervisor	12	29	72,959	91,093	86,340	84,570	87,903	85,925	*	*
Purchasing/Procurement Manager	12	7	72,863	92,626	87,381	79,495	96,025	84,348	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	12	10	53,432	67,781	65,630	60,941	68,500	66,387	*	*
Administrative Assistant	12	7	45,955	55,676	54,762	*	*	*	*	*
Director/VP Finance/CFO	12	10	96,532	121,104	116,729	102,216	131,207	114,580	*	*
Controller/Manager Finance	12	3	79,250	*	91,198	*	*	*	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	12	7	68,587	85,538	79,696	76,456	82,833	80,524	*	*
Director or VP, Customer Service	12	4	97,516	115,672	110,233	101,498	117,214	108,479	*	*
Manager, Customer Service	12	4	74,385	99,982	88,747	85,116	98,937	95,306	*	*
Customer Service Supervisor	12	11	63,241	80,283	70,240	61,761	77,989	72,608	*	*
Financial/Business Analyst	12	12	63,231	79,894	77,227	71,581	83,584	78,830	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	12	4	75,438	95,649	89,813	75,546	102,012	87,745	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	12	5	62,906	77,443	73,614	*	*	*	*	*
Conservation & DM Officer	12	7	63,726	77,105	72,566	62,369	83,379	80,778	*	*
I.S. Director/VP	12	3	101,602	117,410	117,411	*	*	*	*	*
I.S. Manager	12	5	70,855	89,048	84,628	73,400	89,804	88,551	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	12	10	60,665	78,708	74,375	64,400	81,081	79,166	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	12	4	*	*	55,925	*	*	*	*	*
Manager Health & Safety/Loss Control	12	6	69,679	90,191	82,989	76,227	90,856	86,461	*	*

Compensation Analysis: By District

Table 17: LDCs in District 'North Western'

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	4	4	*	*	124,713	109,526	133,629	118,442	*	*
V.P. Operations & Engineering/COO	*	*	*	*	*	*	*	*	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	*	*	*	*	*	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	4	4	78,605	*	94,359	*	*	*	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	*	*	*	*	*	*	*	*	*
Line Supervisor	*	*	*	*	*	*	*	*	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	*	*	*	*	*	*	*	*	*	*
Administrative Assistant	4	4	*	*	44,821	*	*	*	*	*
Director/VP Finance/CFO	*	*	*	*	*	*	*	*	*	*
Controller/Manager Finance	*	*	*	*	*	*	*	*	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	*	*	*	*	*	*	*	*	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By District

Table 18: LDCs in District 'Upper Canada'

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	7	4	*	216,130	206,664	171,808	220,000	200,000	17	23
V.P. Operations & Engineering/COO	7	3	*	*	170,397	*	*	*	*	*
Director/V.P. Operations	7	4	119,844	144,254	144,615	*	*	*	*	*
Director/V.P. Engineering	7	3	122,567	143,447	139,945	*	*	*	*	*
Engineering Manager	7	5	87,803	119,918	109,019	105,698	111,145	107,825	6	8
Distribution Engineer	7	5	85,723	109,312	100,958	*	*	*	5	8
Engineering Supervisor	7	10	73,110	96,641	85,792	81,121	87,863	83,192	5	8
Operations Manager or Superintendent	7	7	86,867	111,860	104,033	93,300	111,583	102,067	5	7
Control Centre Supervisor	7	3	75,903	99,594	95,920	*	*	*	4	8
Meter Shop Supervisor	7	5	79,016	104,762	96,742	94,577	101,777	99,612	5	8
Line Supervisor	7	17	76,683	99,736	91,817	88,024	97,000	90,640	5	7
Purchasing/Procurement Manager	7	3	77,139	103,437	94,249	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	7	7	57,725	70,442	65,463	63,194	71,594	71,000	4	6
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	7	6	119,220	161,339	153,793	118,536	176,763	157,650	10	15
Controller/Manager Finance	7	5	93,879	122,965	112,420	93,300	108,292	104,030	7	9
General Accounting Manager	7	3	87,471	*	101,297	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	7	6	67,446	87,923	80,568	72,183	91,507	83,122	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	7	5	86,486	119,397	100,848	87,687	107,600	104,650	6	9
Customer Service Supervisor	7	5	*	85,737	81,161	73,928	88,183	80,950	5	7
Financial/Business Analyst	7	5	69,825	90,743	77,273	69,348	83,758	75,833	5	7
Director or VP, Regulatory Affairs	7	3	112,693	154,053	143,200	*	*	*	*	*
Manager, Regulatory Affairs	7	4	72,137	95,283	88,093	81,406	93,397	86,710	5	7

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	7	5	69,870	87,309	77,907	70,012	84,261	77,000	6	7
Conservation & DM Officer	7	3	*	80,878	77,481	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	7	10	69,416	87,711	72,655	66,438	81,883	75,666	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	7	4	81,230	108,318	98,465	90,999	103,604	96,138	6	8
Human Resources Generalist/Officer	7	3	63,835	82,506	75,304	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	7	5	78,175	95,810	95,048	*	*	*	6	7

Compensation Analysis: By District

Table 19: LDCs in District 'Western'

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	7	6	146,986	179,425	179,702	157,432	200,129	181,240	22	30
V.P. Operations & Engineering/COO	7	5	126,345	158,163	143,366	122,532	169,125	139,050	23	27
Director/V.P. Operations	7	4	107,662	137,567	126,640	124,995	133,461	131,816	13	13
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	7	6	85,411	108,698	99,907	95,811	106,397	102,301	8	10
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	7	5	82,268	105,384	96,632	93,833	98,850	97,136	8	9
Control Centre Supervisor	7	3	80,638	98,594	96,179	*	*	*	*	*
Meter Shop Supervisor	7	3	74,325	88,235	86,745	*	*	*	*	*
Line Supervisor	7	13	75,301	92,838	88,702	85,413	91,005	89,893	7	8
Purchasing/Procurement Manager	7	3	69,873	85,559	81,203	*	*	*	*	*
Stores/Inventory Control Supervisor	7	3	65,193	78,462	79,130	*	*	*	*	*
Executive Assistant (to President)	7	6	60,065	75,535	70,410	64,803	75,383	68,915	4	5
Administrative Assistant	7	8	54,155	64,681	59,967	58,398	60,978	59,408	*	*
Director/VP Finance/CFO	7	7	115,971	144,440	138,827	122,790	158,463	135,960	18	22
Controller/Manager Finance	*	*	*	*	*	*	*	*	*	*
General Accounting Manager	7	5	71,876	88,837	84,665	82,596	90,100	83,165	*	*
Accounting Supervisor	7	8	63,519	80,653	74,536	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	7	4	93,220	115,070	110,285	107,673	112,925	110,314	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	7	7	62,519	80,762	77,181	75,434	78,917	77,170	4	6
Financial/Business Analyst	7	5	63,914	82,555	71,375	69,736	75,373	73,734	*	*
Director or VP, Regulatory Affairs	7	5	104,802	137,992	127,176	122,403	132,710	125,781	17	21
Manager, Regulatory Affairs	7	4	70,549	89,160	77,250	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	7	3	70,671	83,971	82,462	*	*	*	*	*
Conservation & DM Officer	7	4	74,667	93,093	86,962	77,130	92,877	83,045	*	*
I.S. Director/VP	7	3	105,873	129,558	129,190	*	*	*	*	*
I.S. Manager	7	4	82,910	*	97,864	*	*	*	*	*
I.S. Supervisor/Computer Operations	7	4	72,352	95,045	84,879	*	*	*	*	*
Systems Administrator/Apps Support	7	4	64,257	79,322	85,203	*	*	*	*	*
Human Resources Director/VP	7	4	101,355	121,294	117,497	106,329	128,888	117,721	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	7	4	73,520	85,424	86,042	83,810	88,167	85,935	*	*

Compensation Analysis: By Employee Size

Table 20: LDCs 1 to 20 Employees

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	9	8	101,779	125,176	114,322	106,540	119,490	114,509	*	*
V.P. Operations & Engineering/COO	*	*	*	*	*	*	*	*	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	9	3	85,347	98,070	94,280	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	9	5	78,875	*	91,857	89,951	97,900	92,594	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	*	*	*	*	*	*	*	*	*
Line Supervisor	*	*	*	*	*	*	*	*	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	*	*	*	*	*	*	*	*	*	*
Administrative Assistant	9	3	47,209	55,229	*	*	*	*	*	*
Director/VP Finance/CFO	9	3	*	*	87,165	*	*	*	*	*
Controller/Manager Finance	9	6	84,333	98,997	86,592	84,603	96,799	87,663	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	*	*	*	*	*	*	*	*	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Employee Size

Table 21: LDCs 21 to 40 Employees

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	9	9	121,585	156,403	144,220	139,435	155,197	141,500	*	*
V.P. Operations & Engineering/COO	9	6	98,073	123,606	118,440	111,887	119,455	116,725	*	*
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	9	3	77,027	102,724	*	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	9	6	78,653	101,321	94,440	88,660	99,256	94,577	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	*	*	*	*	*	*	*	*	*
Line Supervisor	9	10	71,581	88,801	83,909	81,570	86,080	84,419	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	9	4	*	*	65,804	61,436	75,306	70,938	*	*
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	9	8	95,479	120,708	108,526	98,251	115,296	107,750	*	*
Controller/Manager Finance	*	*	*	*	*	*	*	*	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	9	4	66,587	88,383	78,932	74,360	82,535	77,964	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	9	4	*	*	65,027	61,367	65,406	61,746	*	*
Financial/Business Analyst	*	*	*	*	*	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Employee Size

Table 22: LDCs 41 to 70 Employees

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	11	8	128,085	170,160	163,269	142,538	157,019	150,300	*	*
V.P. Operations & Engineering/COO	11	3	*	*	131,159	*	*	*	*	*
Director/V.P. Operations	11	4	101,195	118,420	106,657	*	*	*	*	*
Director/V.P. Engineering	11	3	110,996	126,087	124,197	*	*	*	*	*
Engineering Manager	11	5	82,557	105,597	94,788	94,870	98,681	95,618	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	11	3	84,236	102,760	96,030	*	*	*	*	*
Operations Manager or Superintendent	11	9	83,228	106,033	96,028	92,700	97,072	94,870	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	*	4	69,752	89,699	83,800	81,065	84,185	81,450	*	*
Line Supervisor	*	11	74,585	96,385	88,703	86,700	91,288	87,570	*	*
Purchasing/Procurement Manager	*	*	*	*	*	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	11	8	55,093	68,870	67,447	63,655	71,310	67,950	*	*
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	11	9	104,073	131,617	128,077	110,120	140,789	129,000	*	*
Controller/Manager Finance	11	6	77,026	101,165	95,898	93,300	104,030	94,370	*	*
General Accounting Manager	11	3	80,445	102,809	92,425	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	11	5	79,840	105,949	101,109	98,800	107,066	104,650	5	7
Customer Service Supervisor	11	6	58,995	78,299	74,866	71,359	79,736	74,150	*	*
Financial/Business Analyst	11	9	61,522	79,746	71,236	61,821	76,099	70,665	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	11	5	60,067	81,835	79,195	73,752	83,230	79,089	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	11	3	69,330	*	80,580	*	*	*	*	*
Conservation & DM Officer	11	4	66,449	79,422	66,220	58,110	73,941	65,831	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	11	5	64,731	89,292	78,430	73,400	83,250	79,089	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	11	5	56,030	74,573	67,941	64,400	73,093	70,562	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	11	3	*	*	88,360	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	*	*	*	*	*	*	*	*	*	*

Compensation Analysis: By Employee Size

Table 23: LDCs 71 to 100 Employees

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	4	3	*	*	179,008				*	*
V.P. Operations & Engineering/COO	4	4	126,610	162,442	138,598	129,590	148,437	139,429	*	*
Director/V.P. Operations	4	3	100,291	115,233	112,560	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	*	*	*	*	*	*	*	*	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	4	6	75,002	101,224	86,467	86,272	87,869	87,674	*	*
Operations Manager or Superintendent	4	3	79,911	109,556	97,084	*	*	*	*	*
Control Centre Supervisor	*	*	*	*	*	*	*	*	*	*
Meter Shop Supervisor	4	3	79,112	108,295	96,170	*	*	*	*	*
Line Supervisor	4	8	73,158	98,160	85,829	84,106	87,015	85,292	*	*
Purchasing/Procurement Manager	4	3	75,851	103,413	92,721	*	*	*	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	4	5	52,577	66,637	63,363	61,866	64,121	62,624	*	*
Administrative Assistant	*	*	*	*	*	*	*	*	*	*
Director/VP Finance/CFO	4	3	115,831	170,723	152,587	*	*	*	*	*
Controller/Manager Finance	*	*	*	*	*	*	*	*	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	*	*	*	*	*	*	*	*	*	*
Manager, Customer Service	4	3	78,407	106,864	91,372	*	*	*	*	*
Customer Service Supervisor	*	*	*	*	*	*	*	*	*	*
Financial/Business Analyst	4	4	67,244	88,827	77,691	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	4	4	75,139	106,864	91,919	80,740	102,012	90,833	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	*	*	*	*	*	*	*	*	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	*	*	*	*	*	*	*	*	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	4	3	73,685	93,542	81,613	*	*	*	*	*

Compensation Analysis: By Employee Size

Table 24: LDCs 101 to 150 Employees

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	5	5	149,698	176,821	176,821	161,790	179,495	174,900	*	*
V.P. Operations & Engineering/COO	*	*	*	*	*	*	*	*	*	*
Director/V.P. Operations	5	3	110,492	132,096	132,096	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	5	4	89,166	106,314	107,064	105,208	109,361	107,505	*	*
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	5	6	87,211	103,598	102,998	100,070	110,178	100,531	*	*
Control Centre Supervisor	5	4	78,784	95,687	94,569	88,749	99,504	93,684	*	*
Meter Shop Supervisor	5	4	75,526	88,661	86,776	84,011	90,965	88,200	*	*
Line Supervisor	5	17	76,312	91,470	91,291	89,460	90,721	89,804	*	*
Purchasing/Procurement Manager	5	4	68,947	80,835	79,397	78,296	82,166	81,065	*	*
Stores/Inventory Control Supervisor	*	*	*	*	*	*	*	*	*	*
Executive Assistant (to President)	5	5	56,375	67,689	69,782	64,963	73,610	66,387	*	*
Administrative Assistant	5	8	47,051	59,781	58,038	55,439	60,425	57,827	*	*
Director/VP Finance/CFO	5	5	112,587	135,602	135,602	132,824	139,254	133,935	*	*
Controller/Manager Finance	5	3	81,769	96,617	94,660	*	*	*	*	*
General Accounting Manager	*	*	*	*	*	*	*	*	*	*
Accounting Supervisor	*	*	*	*	*	*	*	*	*	*
Billing Supervisor	5	4	68,906	81,573	80,622	*	*	*	*	*
Director or VP, Customer Service	5	3	*	122,979	121,531	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	5	5	61,205	75,940	76,896	*	*	*	*	*
Financial/Business Analyst	5	3	67,318	80,392	79,084	*	*	*	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	5	3	66,758	79,219	77,717	*	*	*	*	*
Conservation & DM Officer	5	5	68,413	82,209	82,209	73,930	86,440	84,348	*	*
I.S. Director/VP	*	*	*	*	*	*	*	*	*	*
I.S. Manager	*	*	*	*	*	*	*	*	*	*
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	5	5	66,016	78,658	86,325	79,561	93,615	86,851	*	*
Human Resources Director/VP	*	*	*	*	*	*	*	*	*	*
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	*	*	*	*	*	*	*	*	*	*
Human Resources Assistant/Coord.	*	*	*	*	*	*	*	*	*	*
Manager Health & Safety/Loss Control	5	5	70,792	85,207	85,930	82,400	93,490	90,002	*	*

Compensation Analysis: By Employee Size

Table 25: LDCs 151 to 300 Employees

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	5	4	*	*	190,424	179,116	194,238	182,930	*	*
V.P. Operations & Engineering/COO	5	4	126,295	164,376	157,025	141,896	176,024	160,895	17	20
Director/V.P. Operations	*	*	*	*	*	*	*	*	*	*
Director/V.P. Engineering	*	*	*	*	*	*	*	*	*	*
Engineering Manager	5	6	92,275	114,128	107,826	105,786	116,280	112,840	8	10
Distribution Engineer	*	*	*	*	*	*	*	*	*	*
Engineering Supervisor	*	*	*	*	*	*	*	*	*	*
Operations Manager or Superintendent	5	5	83,147	105,127	100,230	*	*	*	8	8
Control Centre Supervisor	5	3	81,250	92,762	86,837	*	*	*	*	*
Meter Shop Supervisor	5	5	75,721	89,498	88,652	86,332	90,610	86,840	8	8
Line Supervisor	5	20	75,896	91,344	88,545	85,670	90,610	89,893	10	10
Purchasing/Procurement Manager	5	4	83,581	102,211	97,160	92,207	101,534	96,582	12	12*
Stores/Inventory Control Supervisor	5	4	63,990	77,178	77,178	71,030	82,419	76,271	7	7
Executive Assistant (to President)	5	5	62,068	75,227	74,840	72,400	80,995	73,406	8	8
Administrative Assistant	5	8	54,558	66,025	62,584	59,720	61,025	60,825	6	6
Director/VP Finance/CFO	5	5	125,021	154,890	147,815	130,816	175,275	139,802	20	20
Controller/Manager Finance	5	4	93,763	117,949	112,396	101,164	120,946	109,714	11	11
General Accounting Manager	5	3	83,705	101,583	91,126	*	*	*	*	*
Accounting Supervisor	5	5	67,936	81,494	79,673	*	*	*	7	7
Billing Supervisor	*	*	*	*	*	*	*	*	*	*
Director or VP, Customer Service	5	5	95,130	128,902	124,474	112,800	130,816	114,915	12	15
Manager, Customer Service	5	4	79,779	98,609	92,441	88,660	93,866	90,086	10	10
Customer Service Supervisor	5	6	66,964	81,542	80,518	79,552	80,470	79,991	8	8
Financial/Business Analyst	5	5	62,121	77,974	73,830	68,616	81,891	76,677	*	*
Director or VP, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*
Manager, Regulatory Affairs	*	*	*	*	*	*	*	*	*	*

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	5	5	65,861	79,581	78,520	72,437	82,317	76,234	6	6
Conservation & DM Officer	5	3	76,733	96,625	91,893	*	*	*	*	*
I.S. Director/VP	5	4	103,431	126,869	122,283	115,812	131,110	124,638	17	17
I.S. Manager	5	4	79,673	101,138	96,144	*	*	*	8	8
I.S. Supervisor/Computer Operations	*	*	*	*	*	*	*	*	*	*
Systems Administrator/Apps Support	5	7	60,420	77,624	77,624	77,273	80,148	79,797	*	*
Human Resources Director/VP	5	3	98,960	84,412	113,638	*	*	*	17	17
Human Resources Manager	*	*	*	*	*	*	*	*	*	*
Human Resources Generalist/Officer	5	4	67,693	80,236	75,822	*	*	*	*	*
Human Resources Assistant/Coord.	5	3	53,392	62,645	59,666	*	*	*	*	*
Manager Health & Safety/Loss Control	5	4	80,871	97,285	97,285	90,898	103,588	97,202	10	8

Compensation Analysis: By Employee Size

Table 26: LDCs 301+ Employees

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
President/CEO/GM	4	3	*	*	239,564	*	*	*	22	25
V.P. Operations & Engineering/COO	4	3	*	*	192,733	*	*	*	25	33
Director/V.P. Operations	4	4	114,628	155,488	148,974	135,726	155,949	142,701	12	17
Director/V.P. Engineering	4	3	112,266	152,139	141,461	*	*	*	*	*
Engineering Manager	4	5	89,836	119,006	112,926	107,973	116,633	111,681	7	10
Distribution Engineer	4	12	80,778	107,320	98,228	91,895	104,601	98,268	*	*
Engineering Supervisor	4	9	75,468	101,673	90,319	85,754	96,812	94,173	*	*
Operations Manager or Superintendent	4	9	87,694	116,334	109,298	105,251	113,816	109,770	7	10
Control Centre Supervisor	4	4	76,882	102,401	99,095	*	*	*	*	*
Meter Shop Supervisor	4	6	77,458	102,458	96,959	93,265	101,777	98,083	*	*
Line Supervisor	4	23	78,904	104,267	98,421	96,917	100,072	98,568	*	*
Purchasing/Procurement Manager	4	4	78,427	104,503	97,258	83,538	112,037	98,317	*	*
Stores/Inventory Control Supervisor	4	4	66,598	88,509	87,707	*	*	*	*	*
Executive Assistant (to President)	4	4	55,153	72,852	67,963	64,316	71,793	68,146	*	*
Administrative Assistant	4	15	52,508	70,030	63,653	*	*	*	*	*
Director/VP Finance/CFO	4	4	126,769	180,678	178,230	154,497	209,317	185,585	21	28
Controller/Manager Finance	4	4	91,672	125,130	115,849	91,285	128,022	103,458	8	12
General Accounting Manager	4	3	78,589	106,504	98,759	*	*	*	*	*
Accounting Supervisor	4	8	66,865	88,835	84,848	*	*	*	*	*
Billing Supervisor	4	6	68,315	90,115	86,177	81,635	91,507	86,964	*	*
Director or VP, Customer Service	4	3	103,793	143,644	134,577	*	*	*	*	*
Manager, Customer Service	*	*	*	*	*	*	*	*	*	*
Customer Service Supervisor	4	6	66,598	88,509	82,325	*	*	*	*	*
Financial/Business Analyst	4	10	67,069	89,626	81,660	*	*	*	*	*
Director or VP, Regulatory Affairs	4	3	108,585	150,233	138,604	*	*	*	*	*
Manager, Regulatory Affairs	4	4	78,301	103,968	97,451	89,476	106,844	100,287	7	10

Position	# of Companies	# of Incumbents	Average Range Minimum	Average Range Maximum	Mean (Average Actual)	P25	P75	Median	Average Incentive Target%	Average Incentive Maximum%
Settlement/Rate Analyst	*	*	*	*	*	*	*	*	*	*
Conservation & DM Officer	4	4	76,127	101,243	93,020	82,716	103,565	93,262	*	*
I.S. Director/VP	4	3	113,633	163,014	153,461	*	*	*	*	*
I.S. Manager	4	4	88,401	117,996	107,794	99,457	119,185	110,848	10	15
I.S. Supervisor/Computer Operations	4	4	75,637	100,855	89,954	*	*	*	*	*
Systems Administrator/Apps Support	4	12	68,278	89,995	85,214	82,780	90,430	87,997	*	*
Human Resources Director/VP	4	3	105,160	151,821	141,996	*	*	*	*	*
Human Resources Manager	4	4	83,513	122,072	108,093	*	*	*	*	*
Human Resources Generalist/Officer	4	8	62,935	95,412	85,163	*	*	*	*	*
Human Resources Assistant/Coord.	4	8	52,745	70,634	62,483	58,620	67,835	63,971	*	*
Manager Health & Safety/Loss Control	4	6	82,902	111,204	99,872	90,973	103,444	94,545	10	15

Perquisites – All LDCs

Table 27: Perquisites by Position Level

Perquisite:	CEO/President	Executive	Middle Management	Not Applicable
Company car for business or personal use	17	12	11	22
Association or professional membership dues	39	42	37	4
Supplemental Group Life Insurance	28	27	26	14
Executive training programs or coaching	39	36	25	4
Personal computer for home use	20	16	13	21
Cellular phone for business or personal use	46	45	40	0
Employee Assistance Programs (EAPs)	41	41	40	5
Educational reimbursement	43	44	42	2
Extended vacation allowance	9	8	6	29
Outplacement counselling	11	11	11	30
Flex time	16	17	14	24
Fitness or recreational club memberships or access	17	17	15	25
Financial or legal counselling	8	7	8	32

No. of companies reporting = 47

- *Actual prevalence response - multiple responses accepted*

Table 28: Other Perquisites Noted

Other Perquisites
Three annual vacation floaters
1 week in lieu of overtime
Energy Efficient Interest Free Loans up to $5000 / Computer Interest free loans up to $4000 / Health Club Memberships up to $400 / Wellness Fund reimbursements up to $300 / Tuition Subsidies and Volunteer Subsidies
STD paid @ 100%, Group RSP,
6 weeks after 26 years
Health Services Spending Account - $1,100
Every third Friday off, 2 floater days per calendar year
Computer Acquistion Program
1 additional floater holiday upon start date; 1 additiional floater holiday after 25 years of service

Table 29: Mileage & Auto

CEO Average Monthly car allowance (26 respondents)	**$610.00**
Executive Average Monthly car allowance (18 respondents)	**$515.00**
Average Mileage Reimbursement (47 respondents)	**0.486**

Table 30: Service Periods for Vacation Entitlement

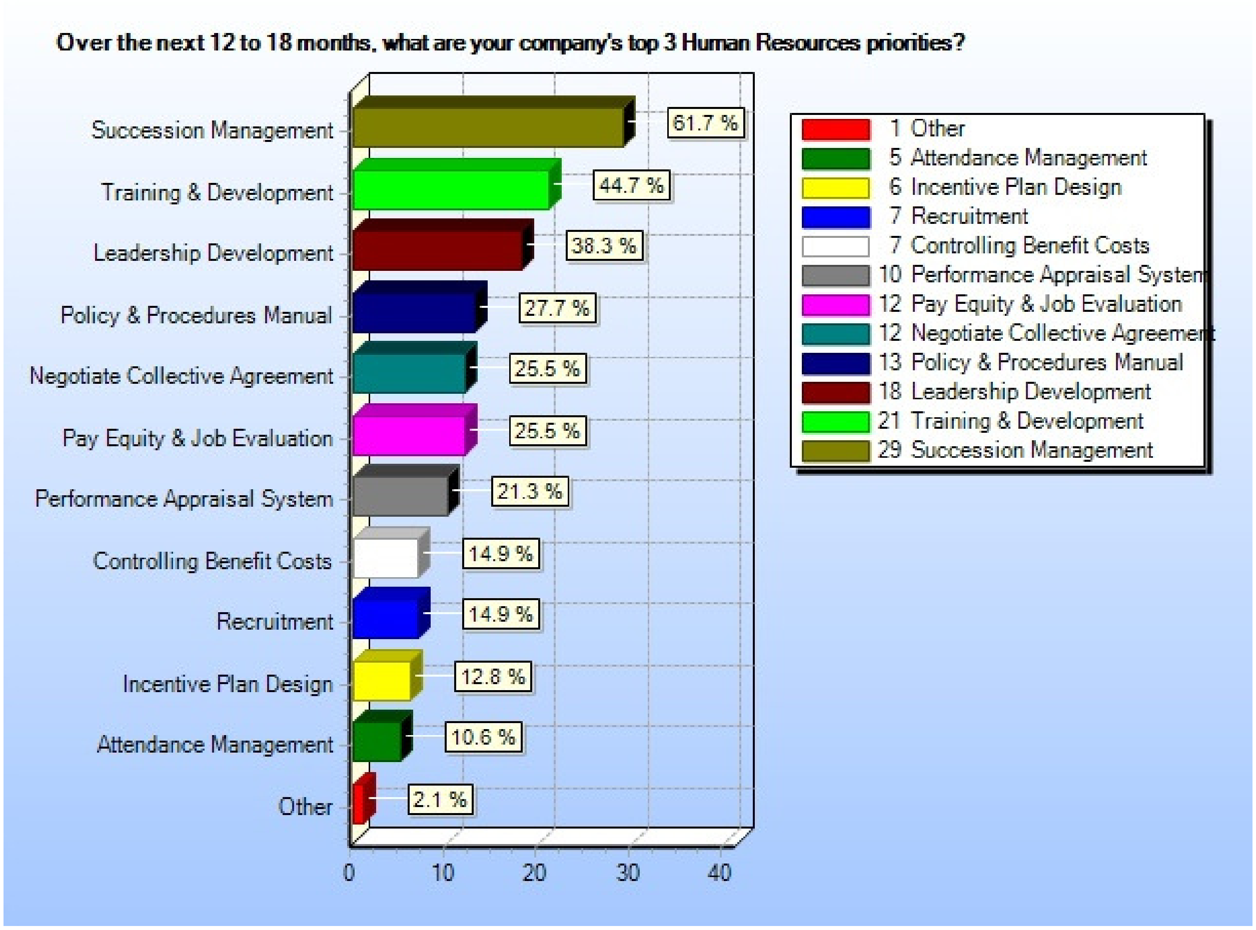
Years of Service:	Eligible for 2 weeks	Eligible for 3 weeks	Eligible for 4 weeks	Eligible for 5 weeks	Eligible for 6 or more weeks
CEO/Pres - 3 years service	5	18	12	8	1
CEO/Pres - 5 years service		21	11	8	3
CEO/Pres - 10 years service		1	4	11	7
CEO/Pres - 15 years service			16	17	9
CEO/Pres - 20 years service				26	15
CEO/Pres - 25 years service				8	33
Executive- 3 years service	6	24	11	2	
Executive- 5 years service		27	12	3	1
Executive- 10 years service		1	31	7	5
Executive- 15 years service			20	17	5
Executive- 20 years service				30	11
Executive- 25 years service				9	33
Middle Management- 3 years service	6	32	5	1	
Middle Management- 5 years service		33	9	2	
Middle Management- 10 years service		1	35	5	2
Middle Management- 15 years service			21	19	3
Middle Management- 20 years service			1	32	8
Middle Management- 25 years service				9	34
Professionals - 3 years service	8	27	4		
Professional - 5 years service		31	8		
Professional - 10 years service		1	34	4	
Professional - 15 years service			20	17	1
Professional - 20 years service				31	7
Professional - 25 years service				9	29
Admin - 3 years service	8	28	3		
Admin - 5 years service		34	6		
Admin - 10 years service		1	36	3	
Admin - 15 years service			22	16	1
Admin - 20 years service			32	32	6
Admin - 25 years service				10	28

Base Compensation Planning

2011 Actual Average Base Pay Increase: Out of 44 respondents, the actual average base pay increase for 2011 was 3.27%. Increases ranged from a low of 1.88% to a high of 8%.	
Percentile	**% Increase**
N	44
25th Percentile	2.73
50th Percentile	3.00
75th Percentile	3.00
Average	3.27
2011 Compensation Structure Adjustment: If your company uses a formal salary range (compensation) structure, by what percentage did you increase the structure in 2011? (E.g. 1%; 2% etc.). 30 Respondents indicated that the structure was adjusted by 2.54% on average. The range was from 0 to 3.25%.	
Percentile	**% Increase**
N	30
25th Percentile	2.13
50th Percentile	3.00
75th Percentile	3.00
Average	2.54
2012 Projected Average Salary Increase: The average response indicates that the projected 2012 average base pay increase will be 2.97%. Increases range from a low of 1.5% to a high of 5.3%.	
Percentile	**% Increase**
N	31
25th Percentile	2.75
50th Percentile	3.00
75th Percentile	3.00
Average	2.97
2012 Projected Compensation Structure Adjustment: By what percentage does your organization plan to increase the salary range/compensation structure in 2012? The average increase in the salary structure will increase by 2.64%. The range was from 0 to 3%.	
Percentile	**% Increase**
N	22
25th Percentile	2.55
50th Percentile	3.00
75th Percentile	3.00
Average	2.64

Top HR Priorities – 2012

The top 3 priorities indicated for 2012 are:
1) Succession Management;
2) Training & Development and
3) Leadership Development.



Appendix:

MEARIE Management Salary Survey – Position Profiles 2011/2012

The following is the 2011-2012 listing of benchmark positions for the survey. Please use them to guide you in identifying job matches.

Please note:

- ❖ Match your jobs to the survey jobs based on content, rather than job title
- ❖ Recognize that your incumbent need not perform all of the functions described in the survey job profile in order to have a valid job match. If 80% of job responsibilities are the same, then you likely have a good match. If not, another job match may be more appropriate or there may not be a good match in this survey.

The survey has not been designed to cover every possible job in your organization - the selected jobs are intended to be benchmarks, so please treat them accordingly. Generally, if you match between 40 to 50 percent of your key jobs to external data, you will be able to compare your salary st MEARIE Management & Board of Directors Compensation Survey –

<u>President, General Manager or CEO</u>

Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.This position may be titled 'General Manager' in smaller utilities.

<u>Vice President Operations & Engineering or Chief Operating Officer</u>

Highest ranking operations position. Reporting to the President/CEO, directs both the operations and engineering functions. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.

<u>Director or Vice President Operations</u>

Reporting to the President/CEO,2 plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.

Director or Vice President Engineering

Highest ranking engineering position. Plans and directs the overall engineering activities and engineering staff of the organization. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.

Engineering Manager

Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P.Eng.

Distribution Engineer

Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P.Eng. Typically reports to the Engineering Manager.

Engineering Supervisor

Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to a professional engineer.

Operations Manager or Superintendent

Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role. In larger utilities, this function may be split into separate sections, each with a non-professional superintendent reporting to a Professional Engineer. Typically reports to VP Engineering and/or VP Operations.

Control Centre Supervisor

Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.

Meter Shop Supervisor

Responsible for overall operation of the Meter department, including operations, budgeting and direction and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Line Supervisor

Coordinates and directs the Field Supervisor/s or lead journey person in the construction and maintenance of transmission and distribution lines and equipment. Works with Field Supervisors or lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the power transmission and distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.

Purchasing or Procurement Manager

Responsible for all purchasing for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Supervises and directs the work of the purchasing or buyers and stores personnel.

Stores or Inventory Control Supervisor

Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with purchasing manager/buyer approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists purchasing department in the sale of obsolete equipment and material.

Executive Assistant to President

Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President/CEO/General Manager and may provide support to other executives.

Administrative Assistant

Performs advanced, diversified and confidential administrative duties for executives and/ or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. This is a non-union position and reports to a senior executive or executive team.

Director or VP Finance or CFO

Highest ranking financially-oriented position within the company. Reporting to the President/CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.

Controller or Manager, Finance

Responsible for all financial reporting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. May be the most senior financial position in a small to mid-size corporation or reporting to a Director/VP Finance in a mid to large corporation.

General Accounting Manager

Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Generally reports to the Controller or CFO.

Accounting (A/R, A/P) Supervisor

Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.

Director or VP Customer Service

The highest ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets; manages activities of CS managers and/or supervisory staff for mid to large size organizations.

Manager Customer Service

Manages a team of customer service representatives in providing information, receiving and responding to customer inquiries, complaint or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls in a medium size organization.

Customer Service Supervisor

Supervises customer service representatives and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated work-flow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Billing Supervisor
This position is responsible for overseeing and management of staff, processes and systems to collect and validate meter reading data, calculate and issue customer invoices and conduct settlement activities in the wholesale and retail markets. The incumbent also monitors compliance with regulation(s) and company policies for billing processes.

Financial or Business Analyst

Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; Process and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents.

Director or V.P., Regulatory Affairs

Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President or Sr. Executive in large organization.

Manager, Regulatory Affairs

Manages the organization's regulatory programs and activities to ensure compliance. Assists the President on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Co-ordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to the President in a small to mid-size organization.

Settlement or Rate Analyst

Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models. Participates in the development of policies.

Conservation and Demand Management Officer

This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.

Information Systems Director or V.P.

Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President or CFO in a mid to large size organization.

Information Systems Manager

Manages and directs staff in areas of computer operations, systems planning, design, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements. Typically reports to Director of Finance in a small to mid-sized organization.

Information Systems Supervisor or Computer Operations Supervisor

Supervises employees who monitor and control computer equipment and data processing. Schedules all production runs including processing of bills, updating inventory system, meter record and all other data processing applications. Maintains hardware and troubleshoots when necessary. May report to a Director/VP, Information Systems.

Systems Administrator or Applications/Systems Support Professional

Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware. Typically reports to the Manager, IS in a large utility or Director or V.P. Information Systems or V.P Finance in a smaller utility.

Human Resources Director or VP

Provides support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors. Generally reports to the President of a mid to large size organization.

Human Resources Manager

Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. May be the most senior HR professional in a small to mid-size organization or report to the top HR professional in a large organization.

Human Resources Generalist or Officer

Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. May assist in the preparation of negotiations. Reports to HR Manager or Senior Executive.

Human Resources Coordinator

Not an administrative assistant role, but rather with the focus on administrative support to one or more functional areas of HR. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications. Reports to HR Manager/Director/V.P.

Manager, Health & Safety or Loss Control

Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

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APPENDIX 4C – ACTUARIAL for POST-RETIREMENT OBLIGATION

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REPORT ON NON-PENSION POST RETIREMENT BENEFIT COST AND DISCLOSURE FOR THE FISCAL YEAR ENDING 31 DECEMBER 2011 UNDER CICA SECTION 3461 AND DISCLOSURE IN RELATION TO THE TRANSITION TO IAS 19 AT 01 JANUARY 2011

LONDON HYDRO INC.

07 FEBRUARY 2012

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Report Highlights

This report has been prepared by Mercer (Canada) Limited at the request of London Hydro Inc. This report provides information on non-pension post retirement obligations and benefit cost calculated in accordance with Section 3461 of the Canadian Institute of Chartered Accountants Handbook (“CICA 3461”) to enable London Hydro Inc. to satisfy accounting and disclosure requirements for financial statements pursuant to CICA 3461.

In addition, Mercer has prepared this report to assist the Company and its auditors in preparing financial reports relating to the transition to International Accounting Standard No. 19 (“IAS 19”).

All sections of this report relate to reporting under CICA 3461, unless specified otherwise. All results related to the transition to IAS 19 are shown in Appendix E.

The Non-Pension Post Retirement Benefit Plan which is a defined benefit plan funded on a cash basis by contributions from London Hydro Inc.

London Hydro Inc.’s fiscal year-end date is 31 December. Please note the measurement date for the plan obligations as described in this report has been changed from 30 September to 31 December for the fiscal year ending 31 December 2011. All balances shown for the 2010 year use balances which are based on a 30 September measurement date.

All results presented in this report are in Canadian dollars.

Fiscal Year Ending 31 December 2011

The benefit cost (also referred to as expense in this report) calculated in accordance with CICA 3461 for the 15 month period ending 31 December 2011 is a charge of $1,180,600. This consists of $240,700 for the period 01 October 2010 to 31 December 2010 and $939,900 for the period 01 January 2011 to 31 December 2011.

The Accrued Benefit Liability as calculated in accordance with CICA 3461 is $10,640,200. The employer contributions and employer-paid benefit payments during the period 01 October 2010 to 31 December 2011 were $477,200. This consists of $106,800 for the period 01 October 2010 to 31 December 2010 and $370,400 for the period 01 January 2011 to 31 December 2011.

Please note in 2011, London Hydro Inc. requested that a valuation be done for the liability of service awards, retirement allowances and medical/dental benefits paid while on long term disability (LTD). The results for these benefits are shown separately at the end of report highlights in a section called 'Other Benefits'.

It should be noted that future health care cost trends are especially difficult to predict and actual experience is likely to differ from expected. The use of a health care cost trend of 1% per year above the assumptions used in this valuation for the fiscal year ending 31 December 2011 would result in an increase to the Accrued Benefit Obligation (ABO) calculated in accordance with CICA 3461 of approximately 9%.

Changes in Plan Provisions

There were no changes in plan provisions since the last disclosure as of 31 December 2010.

Changes in Actuarial Assumptions

There have been changes in actuarial assumptions since the last disclosure as of 31 December 2010. Please refer to the Summary of Assumptions in Appendix C for a description of these changes.

Changes in Actuarial Methods

There were no changes in actuarial methods since the last disclosure as of 31 December 2010.

Transition to International Financial Reporting Standards

The Company will be adopting International Financial Reporting Standards ("IFRS") on 01 January 2012. Due to the requirement to provide comparative information in the first set of IFRS financial statements, the Company will transition to IFRS from current Canadian GAAP on 01 January 2011. On that date, a transition adjustment will be made to retained earnings to bring the existing current CICA 3461 balances in line with the requirements of IAS 19. The Company will continue to report under current Canadian GAAP in 2011. Two sets of financial results will be maintained for 2011, one for current Canadian GAAP and another for IFRS. In 2012, current Canadian GAAP will cease to exist and IFRS will commence with comparative information for 2011.

Under IFRS, the Company will follow the requirements of IAS 19 with respect to the non-pension post retirement benefits plan.

Appendix E contains detailed information on balance sheet entries under IAS 19 at 01 January 2011, on the non-pension post retirement benefit cost and amounts to report in other comprehensive income for 2011 and balance sheet entries at the end of the first comparator year. In addition, it contains information on the principal accounting policies adopted by the Company in relation to the transition to IAS 19.

Other Benefits

In 2011, London Hydro Inc. requested that a valuation be done for the liabilities of service awards, retirement allowances and medical/dental benefits while on LTD. The liability for medical and dental benefits while on LTD as at 31 December 2011 based on a discount rate of 5.0% per annum is $167,518. The liability for service awards and retirement allowances as at 31 December 2011 based on a discount rate of 5.0% per annum is $153,648. These liabilities should be recognized in expense resulting in a total additional expense for other benefits of $321,166 as at 31 December 2011.

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Principal Expense and Disclosure Information

A summary of the principal expense and disclosure information, required pursuant to CICA 3461, for the current fiscal year and the prior fiscal year follows.

Components of Benefit Cost	**15 Month Period Ending 31.12.11**[1]	**Fiscal Year Ending 31.1210**
Current service cost	$345,600	$209,800
Interest cost	784,400	645,500
Actual return on plan assets	0	0
Actuarial loss (gain)	(1,121,300)	1,498,300
Plan amendments	0	0
Curtailment loss (gain)	0	0
Settlement loss (gain)	0	0
Costs arising in the period	**$8,700**	**$2,353,600**
Differences between costs arising in the period and costs recognized in the period in respect of:		
• Return on plan assets	0	0
• Actuarial loss (gain)	1,171,900	(1,498,300)
• Plan amendments	0	0
• Transitional obligation (asset)	0	0
Benefit cost recognized	**$1,180,600**	**$855,300**

[1] Reporting for the period 01 October 2010 to 31 December 2011 to account for the change in measurement date from 30 September to 31 December.

Weighted-Average Assumptions for Expense	**15 Month Period Ending 31.12.11**	**Fiscal Year Ending 31.1210**
Discount rate	5.40%[2]	6.50%
Rate of compensation increase	4.00%	4.00%
Initial weighted average health care trend rate	6.79%[3]	6.93%
Ultimate weighted average health care trend rate	4.60%	4.60%
Year ultimate rate reached	2028	2028

Weighted-Average Assumptions for Disclosure	**31.12.11**	**31.12.10**
Discount rate	5.00%	5.20%
Rate of compensation increase	4.00%	4.00%
Initial weighted average health care trend rate	6.69%[4]	6.81%
Ultimate weighted average health care trend rate	4.50%	4.60%
Year ultimate rate reached	2028	2028

[2] A discount rate of 5.20% per annum is used for the first 3 months of the 2011 benefit cost determination while a discount rate of 5.40% per annum is used for the remaining 12 months of the 2011 benefit cost determination to account for the change in measurement date from 30 September to 31 December.

[3] A trend rate of 6.81% per annum is used for the first 3 months of the 2011 benefits cost determination while a trend rate of 6.79% per annum is used for the remaining 12 months of the 2011 benefit cost determination.

[4] Trend rate applied to the 2011 claim cost (01 July 2011 mid-point) to trend the claim cost forward twelve months to 01 July 2012 mid-point.

Change in Accrued Benefit Obligation (ABO)	15 Month Period Ending 31.12.11	Fiscal Year Ending 31.1210
ABO at end of prior year	**$11,947,300**[5]	**$10,042,000**[6]
Current service cost	345,600	209,800
Interest cost	784,400	645,500
Plan amendments	0	0
Benefits paid	(477,200)[7]	(448,300)[8]
Increase (decrease) in ABO due to curtailment	0	0
Actuarial loss (gain)	(1,121,300)	1,498,300
ABO at end of year	**$11,478,800**[9]	**$11,947,300**

[5] Based on membership data as of 30 June 2009 projected to 30 September 2010.

[6] Based on membership data as of 30 June 2009 projected to 30 September 2019.

[7] Actual benefit payments over the period 01 October 2010 to 31 December 2011 ($106,800 + $370,400)

[8] Actual benefit payments over the period 01 October 2009 to 30 September 2010 ($439,200 - $109,800 + $118,900)

[9] Based on membership data as of 30 September 2011 projected to 31 December 2011.

Change in Plan Assets	15 Month Period Ending 31.12.11	Fiscal Year Ending 31.1210
Fair value of plan assets at end of prior year	**$0**	**$0**
Actual return on plan assets	0	0
Employer contributions	477,200	448,300
Benefits paid	(477,200)	(448,300)
Fair value of plan assets at end of year	**$0**	**$0**

Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	15 Month Period Ending 31.12.11	Fiscal Year Ending 31.1210
Funded status at end of year	**($11,478,800)**	**($11,947,300)**
Employer contributions during period from measurement date to fiscal year end	0	109,800
Unamortized transitional obligation (asset)	0	0
Unamortized past service costs	0	0
Unamortized net actuarial loss (gain)	838,600	2,010,500
Accrued benefit asset (liability)	**($10,640,200)**	**($9,827,000)**

Effect of Change in Assumed Health Care Cost Trend Rates	**15 Month Period Ending 31.12.11**	**Fiscal Year Ending 31.1210**
Effect on current service cost		
• One-percentage point increase	$77,000	$40,700
• One-percentage point decrease	($59,400)	($32,200)
Effect on interest cost		
• One-percentage point increase	$83,800	$55,700
• One-percentage point decrease	($67,500)	($45,700)
Effect on ABO at fiscal year end		
• One-percentage point increase	$1,027,200	$1,207,100
• One-percentage point decrease	($833,900)	($972,900)

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Certification

We have prepared an actuarial valuation of London Hydro Inc.'s benefit obligations for accounting purposes as at 30 June 2009 and extrapolated those results to 30 September 2010 and 31 December 2010. In accordance with our mandate, the purpose of this valuation and extrapolation is to determine the benefit cost of the Plan in accordance with CICA 3461 for the fiscal year beginning 01 October 2010 and ending 31 December 2011 to enable the Company to account for the cost of the Plan under CICA 3461 and IAS 19.

In addition, we have prepared a second actuarial valuation of London Hydro Inc.'s benefit obligations for accounting purposes as at 30 September 2011 and extrapolated those results to 31 December 2011. In accordance with our mandate, the purpose of this valuation and extrapolation is to determine the obligations of the Plan in accordance with CICA 3461 to enable the Company to satisfy the disclosure requirements under CICA 3461.

In addition, Mercer has prepared this report to assist the Company and its auditors in preparing financial reports relating to the transition to International Accounting Standard No. 19 ("IAS 19").

This report has been prepared exclusively for London Hydro Inc. This valuation report may not be relied upon for any purpose other than what is described in this report or by any party other than London Hydro Inc. and its auditors. Mercer is not responsible for the consequences of any other use.

Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date, but are predicted to fall within a reasonable range of possibilities.

To prepare this report, actuarial assumptions, as described in Appendix C, are used to select a single scenario from the range of possibilities. The results of that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of legislated changes to government coverages, plan experience, changes in expectations about the future and other factors.

Because actual plan experience will differ from the assumptions, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

Plan Provisions

The results of the valuations set forth in this report reflect the provisions of the Plan as of the dates of the valuations as reported to us by Management.

The Plan has not been amended since the last valuation for accounting purposes as at 31 December 2011. A summary of the plan provisions is provided in Appendix D. These plan provisions have been certified by London Hydro Inc. under Employer Certification in Appendix F. We have included only those benefits as described in Appendix D in the valuations.

Substantive commitment or Constructive Obligation

There was no substantive commitment as defined under CICA 3461 reported to us by Management.

Data

The valuations and extrapolations as at 31 December 2010 used for expense, are based on membership data as at 30 June 2009 provided by London Hydro Inc. The valuations and extrapolations as at 31 December 2011 used for disclosure, are based on membership data as at 30 September 2011 provided by London Hydro Inc. The membership data is summarized in Appendix B.

Subsequent Events

Based on discussions with representatives of London Hydro Inc., to our knowledge there have been no events subsequent to 31 December 2011 which, in our opinion, would have a material impact on the results of the valuations and extrapolations.

Methods and Assumptions

The actuarial valuation methods, and Management accounting policies and assumptions used in the valuations and determination of benefit cost are summarized in Appendix C.

Valuation methods and assumptions are the same as the prior year's valuation with the exception of the following:

- London Hydro Inc.'s measurement has changed from 30 September to 31 December and as a result, fiscal 2011 represents the 15-month period from 1 October 2010 to 31 December 2011. The choice of using a 15-month period to affect the change in measurement date was made by London Hydro Inc. There were no changes in actuarial methods since the last disclosure as of 31 December 2010.

- The discount rate was updated from 5.20% per annum as at 30 September 2010 to 5.40% per annum as at 31 December 2010 to 5.00% per annum as at 31 December 2011.

Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future valuations and will affect future benefit cost.

Actuarial computations in accordance with CICA 3461 and IAS 19 are for purposes of enabling London Hydro Inc. to fulfill accounting requirements pursuant to CICA 3461 and IAS 19. Determination for purposes other than meeting employer financial accounting requirements may be significantly different from the results reported herein. Accordingly, additional determinations are needed for other purposes such as adequacy of funding for the ongoing plan, purchase price calculations or plan design costings.

Statement of Opinion

The methods used in the valuations of benefit obligations and determination of plan costs were selected by Management in accordance with the requirements of CICA 3461 and in accordance with the requirements of IAS 19.

The preparers of the financial statements (assumed to be Management of the company) have selected the assumptions used in the valuations of the plan obligations and determination of plan costs. They are Management's best-estimate assumptions, selected for accounting purposes, in accordance with CICA 3461 and in accordance with IAS 19. I am not expressing any opinion on these assumptions.

In my opinion,

- The data on which the valuations are based is sufficient and reliable for the purposes of the valuations, and
- The calculations have been made in accordance with the requirements of CICA 3461 and in accordance with IAS 19.

This report has been prepared and my opinion given, in accordance with accepted actuarial practice in Canada.

Respectfully submitted,

Lois Pavlich

Lois Pavlich
FSA, FCIA

FEB 09 2012

Date

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APPENDIX A

Development of Costs

This Appendix shows the financial position of the Plan and the calculation of the various components of plan costs under CICA 3461.

Financial Position of the Plan

		01.01.11	01.10.10
1.	ABO		
	a. Retirees and surviving spouses	($6,435,000)	($6,542,100)
	b. Active fully eligible members	(1,471,700)	(1,491,400)
	c. Active not fully eligible members	(3,809,700)	(3,913,800)
	d. Total (a. + b. + c.)	**($11,716,400)**	**($11,947,300)**
2.	Fair value of plan assets	0	0
3.	**Surplus (Deficit) (1.d. + 2.)**	**($11,716,400)**	**($11,947,300)**
4.	Employer contributions during period from measurement date to fiscal year end	0	106,800
5.	Unamortized transitional obligation (asset)	0	0
6.	Unamortized past service cost	0	0
7.	Unamortized net actuarial loss (gain)	1,645,700	2,013,500
8.	**Accrued benefit asset (liability) (3. + 4. + 5. + 6. + 7.)**	**($10,070,700)**	**($9,827,000)**

Reconciliation of Accrued Benefit Asset (Liability)

		15 Month Period Ending 31.12.11	Fiscal Year Ending 31.12.10
1.	Accrued benefit asset (liability) at beginning of year	($9,827,000)	($9,410,900)
2.	Benefit cost for the year	(1,180,600)	(855,300)
3.	Benefit payments[10]	367,400	439,200
4.	**Accrued benefit asset (liability) at end of year**	**($10,640,200)**	**($9,827,000)**

Components of the benefit cost calculations are developed below.

Interest Cost

For Period 01 October 2010 to 31 December 2010			**15 Month Period Ending 31.12.11**
1.	ABO		$11,947,300
2.	a.	Current service cost	283,300
	b.	Weighted for timing	283,300
3.	a.	Plan amendment	0
	b.	Weighted for timing	0
4.	a.	Benefit payments	655,800
	b.	Weighted for timing	327,900
5.	**Average ABO (1. + 2.b. + 3.b. – 4.b.)**		**$11,936,100**
6.	Discount rate		5.2%
7.	**Annual Interest cost (5. × 6.)**		**$618,900**
8.	Period Weighting		0.25
9.	**Interest Cost for Period (7. x 8.)**		**$154,700**

[10] Benefit payments are $370,400 + $106,800 - $109,800

For Period 01 January 2011 to 31 December	**15 Month Period Ending 31.12.11**	**Fiscal Year Ending 31.12.10**
1. ABO	$11,716,400	$10,042,000
2. a. Current service cost	274,800	209,800
b. Weighted for timing	274,800	209,800
3. a. Plan amendment	0	0
b. Weighted for timing	0	0
4. a. Benefit payments	661,500	643,300
b. Weighted for timing	330,800	321,700
5. Average ABO (1. + 2.b. + 3.b. – 4.b.)	**$11,660,400**	**$9,930,100**
6. Discount rate	5.4%	6.5%
7. Interest cost (5. × 6.)	**$629,700**	**$645,500**

Total Interest cost for the Period 01 October 2010 to 31 December 2011	**$784,400**

Amortization Amounts

Amortizations		Unamortized Amount as of 01.01.11	Years Remaining	Annual Amortization Amount
1.	Transitional obligation (asset)	$0	N/A	**$0**
2.	Past service cost	$0	N/A	**$0**
3.	Unamortized loss (gain) subject to amortization as of 01 October 2010			
	a. Unamortized net actuarial loss (gain*)*			$2,010,600
	b. ABO			11,947,300
	c. 10% of ABO (b.)			1,194,700
	d. Unamortized net actuarial loss (gain) subject to amortization (excess of a. over c., if any)			815,900
	e. Expected average remaining service lifetime			13.4
	f. Annual Amortization amount (d. ÷ e.)			$60,900
	g. Period Weighting			0.25
	h. Amortization amount for Period (f. x g.)			$15,200
4.	Unamortized loss (gain) subject to amortization as of 01 January 2011			
	a. Unamortized net actuarial loss (gain*)*			$1,645,700
	b. ABO			11,716,400
	c. 10% of ABO (b.)			1,171,600
	d. Unamortized net actuarial loss (gain) subject to amortization (excess of a. over c., if any)			474,100
	e. Expected average remaining service lifetime			13.4
	f. Annual Amortization amount (d. ÷ e.)			$35,400
	g. Period Weighting			1
	h. Amortization amount for Period (f. ÷ g.)			$35,400
5.	**Total Unamortized loss (gain) subject to amortization for Fiscal Year Ending 31 December 2011 (3.h. + 4.h.)**			**$50,600**

Analysis of Loss (Gain) in Obligation (ABO) under CICA 3461 recognized for the period 01 October 2010 to 31 December 2011

Gains and Losses Due to:		Due to Remeasurement as of 31.12.11
1.	Change in discount rate from 5.2% per annum to 5.0% per annum	$249,400
2.	Change in claim costs	(1,010,200)
3.	Change in trend assumptions	(80,800)
4.	All other demographic (gain) loss	68,500
5.	Benefit payments differing from expected	(348,200)
6.	**Total**	**($1,121,300)**

Analysis of Loss (Gain) in Obligation (ABO) under IAS 19 recognized for the period 01 January 2011 to 31 December 2011

Gains and Losses Due to:		Due to Remeasurement as of 31.12.11
1.	Change in discount rate from 5.4% per annum to 4.4% per annum	$1,448,200
2.	Change in claim costs	(1,010,200)
3.	Change in trend assumptions	(80,800)
4.	All other demographic (gain) loss	68,500
5.	Benefit payments differing from expected	(291,200)
6.	**Total**	**$134,500**

APPENDIX B

Membership Data

The actuarial valuations are based on membership data as at 30 September 2011 provided by London Hydro Inc.

We have not independently verified the accuracy or completeness of the data except to the extent required by generally accepted professional standards and practices. Mercer will not be held responsible for any liability arising from the use of incomplete, inaccurate or not up-to-date data or documentation. We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), earnings, and service. The results of these tests were satisfactory.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

Analysis of Membership Data

	30.09.11	**30.06.09**
Total Active Members		
Number		
• Fully Eligible	62	49
• Not Fully Eligible	221	208
• **Total**	**283**	**257**
Average age	46.6 years	47.0 years
Average years of service	16.2	17.0

	30.09.11	30.06.09
Total Retired Members and Surviving Spouses		
Number		
Pre-65	37	43
Post-65	173	169
Average age		
Pre-65	61.1 years	60.6 years
Post-65	77.7 years	77.4 years
Number with life insurance		
Pre-65	10	14
Post-65	127	132
Number with Medical or Dental Benefits		
Pre-65	37	43
Post-65	132	132
Number with Family coverage		
Pre-65	31	36
Post-65	66	72
Average age of spouse		
Pre-65	60.3 years	58.9 years
Post-65	73.8 years	72.8 years
Retired Members with Pre-65 Hospital, Drug, EHC, Vision, OOC and Dental Benefits		
Number		
Single	5	6
Family	32	37
Total	**37**	**43**
Average age of retiree	61.1 years	60.7 years
Average age of spouse	60.3 years	58.9 years
Retired Members with Pre-65 Life Insurance Benefits		
• Number	10	14
• Average age of retiree	62.7 years	62.0 years
• Average insurance amount	$28,717	$29,525

	30.09.11	30.06.09
Retired Members with Post-65 Hospital Benefits		
Number		
Single	17	17
Family	35	39
Total	**52**	**56**
Average age of retiree	79.5 years	78.3 years
Average age of spouse	75.4 years	75.2 years
Retired Members with Post-65 Drug, EHC and OOC Benefits		
Number		
Single	36	30
Family	88	95
Total	**124**	**125**
Average age of retiree	77.5 years	76.6 years
Average age of spouse	74.0 years	73.0 years
Retired Members with Post-65 Vision Benefits		
Number		
Single	20	18
Family	26	28
Total	**46**	**46**
Average age of retiree	76.4 years	75.2 years
Average age of spouse	73.4 years	74.2 years
Retired Members with Post-65 Dental Benefits		
Number		
Single	19	14
Family	38	40
Total	**57**	**54**
Average age of retiree	76.4 years	75.2 years
Average age of spouse	72.1 years	71.3 years

	30.09.11	30.06.09
Retired Members with Post-65 Life Insurance Benefits		
• Number	127	132
• Average age of retiree	78.3 years	77.7 years
• Average insurance amount (valuation year)	$37,684	$37,626

Analysis of Post Employment Membership Data

	30.09.11
Total Disabled Members	
Number Receiving Continuation of Medical & Dental	7
Average age	47.4 years
Average disability duration	5.6

APPENDIX C

Valuation Methods and Assumptions

This Appendix describes the methods and assumptions used to value the Plan as well as accounting policies used to calculate the benefit cost.

Cost Method

ABO numbers shown in this report are computed using the Projected Benefit Method Pro Rated on Service, as defined in CICA 3461. The objective under this method is to expense each member's benefits under the Plan as they accrue, taking into consideration projections of benefit costs to and during retirement. The ABO is determined under this method as follows:

Under the Projected Benefit Method Pro Rated on Service, an equal portion of the total estimated future benefit is attributed to each year of service.

The ABO is the actuarial present value of the accrued benefit as of the valuation date and the current service cost is the actuarial present value of the benefit deemed to accrue in the fiscal year.

For retirees, spouses and surviving spouses, the ABO is the present value of all future projected benefits.

For each active member, a "full eligibility" date is determined as the first date the member has or will have met the age and service requirements to qualify for all benefits after retirement.

Full eligibility is age 55.

For active members who have reached "full eligibility", the ABO is the present value as of the valuation date of all future projected benefits. For these members, the service cost is zero.

For active members who have not yet reached "full eligibility", the ABO is the present value of all future projected benefits, multiplied by the ratio of service at the valuation date to projected service at "full eligibility". For these members, the current service cost is the present value of benefits as of the valuation date deemed to accrue in the fiscal year, and is determined as the present value of all future projected benefits divided by the projected service at "full eligibility".

The Plan's **current service cost** is the sum of the individual current service costs, and the Plan's **ABO** is the sum of the individual ABOs for all members under the Plan.

Changes Since Prior Valuation

- Measurement date changed from 30 September to 31 December.
- Age 65 per capita claims cost assumptions changed.
- Prescription Drug trend assumption changed to an initial trend of 8.5% per annum in 2011 grading down to 4.5% per annum in and after 2028.
- Medical trend assumption changed to a flat 4.5% per annum.
- Discount rate changed from 5.20% per annum to 5.40% per annum for the first 3 months of the benefit cost determination.
- Discount rate changed from 5.40% per annum to 5.00% per annum for 2011 disclosure and the last 12 months of the 2011 benefit cost determination

Funding Policy

The non-pension post retirement benefits are funded on a pay-as-you-go basis. The company funds on a cash basis as benefits are paid. No assets have been segregated and restricted to provide the non-pension post retirement benefits.

Accounting Policies

The Company has elected to amortize past service costs resulting from plan amendments on a linear basis over the expected average remaining service period (to full eligibility) of active members expected to receive benefits under the Plan (9.8 years).

Cumulative gains and losses in excess of 10% of the beginning of year ABO are amortized over the expected average remaining service of active members expected to receive benefits under the Plan (13.3 years).

Obligations are attributed to the period beginning on the member's date of hire and ending on the date the member reaches first full eligibility for benefits.

London Hydro Inc.'s fiscal year-end date is 31 December and the measurement date of the company's obligations has been updated from 30 September to 31 December, for the purposes of this report.

We have used claims and expense data submitted by the London Hydro's insurer without further audit and participant data as supplied by London Hydro. We have reviewed the information for internal consistency, and we have no reason to doubt its substantial accuracy.

Summary of Assumptions for Post Retirement Plan

The following assumptions were used in valuing the benefit obligations under the Plan.

Measurement date used for 2010 disclosure	September 30	
Measurement date used for 2011 disclosure	December 31	
Discount rate	▪ 6.50% per annum for the 2010 benefit cost determination ▪ 5.20% per annum for 31 December 2010 disclosure and the 2011 benefit cost determination relating to the period 01 October 2010 to 31 December 2010 ▪ 5.40% per annum for the 2011 benefit cost determination relating to the period 01 January 2011 to 31 December 2011 ▪ 5.00% per annum for 31 December 2011 disclosure under CICA[11] ▪ 4.40% per annum for 31 December 2011 disclosure under IAS 19[11]	
Salary increases	4.00% per annum	
Health care cost trend rates for 2010 disclosure and 2011 benefit cost determination	Hospital	5.0% per annum
	Prescription drugs	9.0% per annum in 2008 grading down to 4.5% per annum in and after 2028
	Other Medical	5.0% per annum
	Vision Care	4.5% per annum
	Dental	4.5% per annum
Health care cost trend rates for 2011 disclosure	Hospital	4.5% per annum
	Prescription drugs	8.5% per annum in 2011 grading down to 4.5% per annum in and after 2028
	Other Medical	4.5% per annum
	Vision Care	4.5% per annum
	Dental	4.5% per annum

[11] Please note that London Hydro Inc. chose the mercer method to determine discount rates under CICA 3461 and the CIA method to determine discount rates under IAS 19.

Mortality	UP 1994 Table with generational mortality improvement
Withdrawal	Mercer "Ontario Light" Termination table Rates at sample ages are shown below:

Age	Male	Female
20	18.8%	18.8%
30	5.6%	5.6%
40	2.2%	2.2%
50	1.2%	1.2%
60	0.0%	0.0%

No withdrawal assumed after attainment of eligibility for retirement.

Retirement rates

Age	Rate
55 – 59	7%
60 – 62	11%
63	12%
64	13%
65+	100%

Dependent coverage	80% of active members are assumed to elect dependant coverage upon retirement Actual coverage data provided by the client is used for retired members.
Age difference	For active members, a male is assumed to be 3 years older than his spouse. Actual data provided by the client is used for retired members.

2010 Age 65 per capita claims costs for 2010 disclosure and 2011 benefit cost determination[12]

	Pre-65 Plan	Post-65 Plan
Semi-private hospital	$91	$218
Prescription drugs	2,057	666
Other medical	206	182
Vision care	85	85
Out of Province	409	409
Dental care	448	581
Total	**$3,296**	**$2,141**

[12] 2010 claim cost (July 1, 2010 mid-point). Post-65 claims cost is before adjustment for 15% company cost sharing.

		Pre-65 Plan	Post-65 Plan
2011 Age 65 per capita claims costs for 2011 disclosure[13]	Semi-private hospital	$97	$145
	Prescription drugs	2,057	726
	Other medical	266	242
	Vision care	109	85
	Out of Province	230	363
	Dental care	557	811
	Total	**$3,316**	**$2,372**

Claims cost development

The 2011 age 65 per capita claim costs are based on the group's claims experience from 01 October 2008 to 30 September 2011 trended to the mid point of the valuation period, adjusted to age 65 and loaded 21% for administrative expenses and taxes.

Claims costs were developed separately for Pre-65 and Post-65 retirees based on separate experience for each of these groups.

The Out of Province rates were developed using 01 January 2012 premium rates.

Aging factors

The change in claiming levels from one age to the next are shown below for sample ages:

Age	Prescription Drug	Semi Private Hospital	Other Medical	Vision	Dental
55	3.8%	7.0%	(0.2)%	(0.5)%	(0.4)%
60	2.8%	7.8%	(0.6)%	(0.6)%	(0.7)%
65	2.1%	10.0%	(0.5)%	(0.6)%	(0.9)%
70	1.1%	9.5%	1.2%	(0.5)%	(1.1)%
75	0.5%	9.3%	1.7%	(0.6)%	(1.3)%
80	(0.2)%	8.2%	2.2%	(0.6)%	(1.8)%
85	(0.3)%	6.8%	2.3%	(0.7)%	(2.9)%

13 2011 claim cost (April 1, 2011 mid-point). Post-65 claims cost is before adjustment for 15% company cost sharing.

Administrative expenses as a percentage of paid claims	Medical	10.0%	Not applied to Out of Province as valuing fully pooled premium
	Dental	10.0%	
	Life insurance	16.8%	
Taxes	8% of claims and administrative expenses for all medical and dental benefits. 2% premium tax on claims and administration expenses. 8% sales tax on claims, administration expenses and premium tax for life insurance.		
Participation – Pre-65	100% of members assumed to participate in the pre-65 retiree health plan.		
Participation – Post-65	• 100% for drugs, OOP and other medical • 50% for hospital, vision and dental		

Summary of Assumptions for Service Awards and Retirement Allowances

The following assumptions were used in valuing the benefit obligations under the Plan.

Measurement date	December 31
Discount rate	▪ 5.00% per annum for 31 December 2011 disclosure under CICA ▪ 4.40% per annum for 31 December 2011 disclosure under IAS 19
Mortality	UP 1994 Table with generational mortality improvement
Withdrawal	Mercer "Ontario Light" Termination table Rates at sample ages are shown below:

Age	Male	Female
20	18.8%	18.8%
30	5.6%	5.6%
40	2.2%	2.2%
50	1.2%	1.2%
60	0.0%	0.0%

No withdrawal assumed after attainment of eligibility for retirement.

Retirement rates

Age	Rate
55 – 59	7%
60 – 62	11%
63	12%
64	13%
65+	100%

Taxes	13% sales HST tax

Summary of Assumptions for LTD Plan

The following assumptions were used in valuing the benefit obligations under the Plan.

Measurement date	December 31		
Discount rate	▪ 5.00% per annum for 31 December 2011 disclosure under CICA ▪ 4.40% per annum for 31 December 2011 disclosure under IAS 19		
2011 premiums for 2011 disclosure		**Single**	**Family**
	Semi-private hospital	$149	$262
	Vision care	96	314
	Other Medical	3,497	5,390
	Total Medical	3,742	5,966
	Dental care	695	1,609
	Total	**$4,437**	**$7,575**
Premium development	The 2011 per capita claim costs are based on the group's healthy premium rates multiplied by a disabled factor of 3 for all medical benefits.		
Termination of Benefits	Age 65		
Recovery assumption	Mortality and recovery rate assumptions for medical and dental benefits provided to disabled employees are based on Canadian Group LTD Termination Experience 1988-1997. Modification factors vary by age and time since disability and are available upon request.		

Claims Cost Development

The 2011 age 65 per capita claim costs are based on the group's claims experience from 01 October 2008 to 30 September 2011 trended to the mid point of the valuation period, adjusted to age 65 and loaded 21% for administrative expenses and taxes. Claims costs were developed separately for Pre-65 and Post-65 retirees based on separate experience for each of these groups.

The per covered member claim costs used in the 30 September 2011 valuation and extrapolated for purposes of determining the liabilities as at 31 December 2011 were based on the actual retiree and dependent claims information for the 01 October 2008 to 30 September 2011, increased with assumed health care cost trend rates to 2011. This claims experience was collected and analysed separately for Semi-Private Hospital, Prescription Drugs, Other Medical, Vision Care, Out of Province and Dental benefits. Claims experience was also collected and analysed separately for Pre-65 and Post-65 retirees.

A description of the process used to set the "Age 65 per capita claims costs" (shown in Appendix C – Summary of Assumptions) is as follows:

- For each calendar year of claims, a cost per covered member was developed by dividing the total annual claims by the total number of eligible retirees, and dependents covered during the year.
- This cost per person has been adjusted to the cost per covered member at age 65 based on the individual ages of the covered members using the "Aging factors" assumptions shown in Appendix C – Summary of Assumptions).
- These costs have been increased to include the cost of insurance company administrative expenses and provincial taxes charged on the claims.
- The costs are then increased with assumed health care cost trend rates from the claims experience year to the midpoint of the valuation year of 30 September 2011.
- As indicated, this analysis was performed for each experience period 2008/09, 2009/10 and 2010/11. The assumed cost per covered member for the 30 September 2011 valuation was based on a weighted average of the costs for the three years, as follows:

Percentage Contribution to Valuation Assumed 2011 Claim Cost	Hospital, Vision, Other medical and Dental	Prescription Drugs
2008/09 claims experience	**30%**	**40%**
2009/10 claims experience	**40%**	**40%**
2010/11 claims experience	**40%**	**20%**
Total	**100%**	**100%**

Development of Non-Pension Post Retirement **Pre-65** Claims Costs Assumptions for 2011 Per Covered Member Claim Costs at Age 65

	2010/11	2009/10	2008/09
Actual London Hydro Inc. Pre-65 retirees' paid claims (before administration costs and taxes)[14]			
Hospital	$ 2,115	$ 1,410	$ 1,410
Drug	58,250	96,394	102,726
Vision care	5,896	6,030	6,731
Other medical	16,204	14,293	11,947
Dental	28,412	32,872	29,852
Total	$ 110,877	$ 151,000	$ 152,666
Number of London Hydro Inc. retirees, spouses and surviving spouses			
▪ Eligible for medical benefits	67	80	83
▪ Eligible for prescription drug benefits	67	80	84
▪ Eligible for dental benefits	67	80	83
Pre-65 Per covered member costs			
Hospital	$ 31.57	$ 17.63	$ 16.99
Drug	869.41	1,204.93	1,222.93
Vision care	88.00	75.38	80.13
Other medical	241.84	178.66	142.23
Dental	424.06	410.90	359.66
Total	$ 1,654.88	$ 1,887.50	$ 1,821.94
Trend to 31 March 2012			
Hospital	1.0450	1.0920	1.1412
Drug	1.0833	1.1759	1.2791
Vision care	1.0000	1.0000	1.0000
Other medical	1.0450	1.0920	1.1412
Dental	1.0450	1.0920	1.1412
2011 Pre-65 per covered member costs			
Hospital	$ 32.99	$ 19.25	$ 19.39
Drug	941.78	1,416.83	1,564.18
Vision care	88.00	75.38	80.13
Other medical	252.73	195.10	162.31
Dental	443.15	448.72	410.44
Total	$ 1,758.65	$ 2,155.28	$ 2,236.44

[14] The Out of Province Costs are not listed here as the premium rates were used in development rather then actual costs.

Weighting for Hospital, Vision, Other medical and Dental	**40%**	**30%**	**30%**
Weighting for Prescription Drugs	**20%**	**40%**	**40%**

2011 Pre-65 per covered member costs	
Hospital	$ 24.78
Drug	1,380.76
Vision care	81.85
Other medical	208.31
Dental	435.00
Total	$ 2,130.72

Adjustment factors to convert 2011 per covered member costs into age 65 per covered member costs	
Hospital	3.23
Drug	1.23
Vision care	1.10
Other medical	1.06
Dental	1.06

Pre-65 Per covered member age 65 claims costs (2011 per covered member costs x adjustment factors)	
Hospital	$ 80.00
Drug - incorporating 55% drug offset	1,700.00
Vision care	90.00
Other medical	220.00
Dental	460.00
Total	$ 2,550.00

Administration costs and taxes		
▪ Administration costs for medical	10.00%	of claims
▪ Premium and sales taxes	10.00%	of claims
Total administration costs and taxes	**21.00%**	**of claims**

Administration costs and taxes		
▪ Administration costs for dental	10.00%	of claims
▪ Premium and sales taxes	10.00%	of claims
Total administration costs and taxes	**21.00%**	**of claims**

Pre-65 Per covered member age 65 claims costs with administration costs and taxes

Hospital	$ 96.80
Drug	2,057.00
Vision care	108.90
Other medical	266.20
Dental	556.60
Total	$ 3,085.50

Benefit adjustment factors due to differences in plan provisions

Hospital	1.00
Drug	1.00
Vision care	1.00
Other medical	1.00
Dental	1.00

London Hydro Inc. 2011 Pre-65 per covered member age 65 claims costs with administration costs and taxes

	Total
Hospital	$ 97
Drug	2,057
Vision care	109
Other medical	266
Dental	557
Total	$ 3,086
Out of Province Premiums	230
Total	$ 3,316

Development of Non-Pension Post Retirement **Post-65** Claims Costs Assumptions for 2011 Per Covered Member Claim Costs at Age 65

	2010/11	2009/10	2008/09
Actual London Hydro Inc. Post-65 retirees' paid claims (before administration costs and taxes)[15]			
Hospital	$ 19,035	$ 10,164	$ 54,575
Drug	111,852	103,229	96,620
Vision care	5,391	1,755	3,600
Other medical	35,078	28,392	22,128
Dental	55,085	46,625	38,634
Total	$ 5,100	$ 1,400	$ 2,125
Number of London Hydro Inc. retirees, spouses and surviving spouses			
▪ Eligible for medical benefits	74	75	79
▪ Eligible for prescription drug benefits	191	189	188
▪ Eligible for dental benefits	91	86	82
Post-65 Per covered member costs			
Hospital	$ 257.23	$ 135.52	$ 690.82
Drug	585.61	546.19	513.93
Vision care	85.57	28.77	59.02
Other medical	256.51	170.51	149.42
Dental	605.33	542.15	471.15
Total	$ 1,790.25	$ 1,423.13	$ 1,884.34
Trend to 31 March 2012			
Hospital	1.0450	1.0920	1.1412
Drug	1.0833	1.1759	1.2791
Vision care	1.0000	1.0000	1.0000
Other medical	1.0450	1.0920	1.1412
Dental	1.0450	1.0920	1.1412
2011 Post-65 per covered member costs			
Hospital	$ 268.81	$ 147.99	$ 788.34
Drug	634.36	642.24	657.35
Vision care	85.57	28.77	59.02
Other medical	268.06	186.20	170.51
Dental	632.57	592.04	537.66

[15] The Out of Province Costs are not listed here as the premium rates were used in development rather then actual costs.

Total	$ 1,889.36	$ 1,597.24	$ 2,212.88
Weighting	**40%**	**30%**	**30%**

2011 Post-65 per covered member costs	
Hospital	$ 388.42
Drug	643.62
Vision care	60.56
Other medical	214.24
Dental	591.94
Total	$ 1,898.78

Adjustment factors to convert 2011 per covered member costs into age 65 per covered member costs	
Hospital	0.31
Drug	0.93
Vision care	1.16
Other medical	0.93
Dental	1.13

Post-65 Per covered member age 65 claims costs (2011 per covered member costs x adjustment factors)	
Hospital	$ 120.00
Drug - incorporating 55% drug offset	600.00
Vision care	70.00
Other medical	200.00
Dental	670.00
Total	$ 1,660.00

Administration costs and taxes		
▪ Administration costs for medical	10.00%	of claims
▪ Premium and sales taxes	10.00%	of claims
Total administration costs and taxes	**21.00%**	**of claims**

Administration costs and taxes		
▪ Administration costs for dental	10.00%	of claims
▪ Premium and sales taxes	10.00%	of claims
Total administration costs and taxes	**21.00%**	**of claims**

Post-65 Per covered member age 65 claims costs with administration costs and taxes

Hospital	$ 145.20
Drug	726.00
Vision care	84.70
Other medical	242.00
Dental	810.70
Total	$ 2,008.60

Benefit adjustment factors due to differences in plan provisions

Hospital	1.00
Drug	1.00
Vision care	1.00
Other medical	1.00
Dental	1.00

London Hydro Inc. 2011 Post-65 per covered member age 65 claims costs with administration costs and taxes

	Total
Hospital	$ 145
Drug	726
Vision care	85
Other medical	242
Dental	811
Total	$ 2,009
Out of Province Premiums	363
Total	$ 2,372

APPENDIX D

Summary of Plan Provisions

Hourly and Salaried employees who retire from active service after age 55 are entitled to paid up life insurance and continued health and dental benefit coverage for themselves and their eligible family for life.

In general, retirees are entitled to $10,000 paid up life insurance. However, there are certain grandfathered active employees (5 as of 30 June 2009) who are entitled to retiree life insurance equal to 50% of their pre-retirement annual base earnings. Also, the majority of current retirees are entitled to non-paid up life insurance amounts under previous plan provisions equal to flat dollar amounts, 50% of their pre-retirement annual base earnings, or 70% of their pre-retirement life benefit.

Retiree Divisions

Upon retirement, pre-age 65 hourly retirees are placed in Division 7999 and salaried retirees are placed in Division 7998. Upon the attainment of age 65, hourly and salaried retirees are classified as Division 1983 and 3282 respectively.

The plan provisions for all divisions are summarized below.

Division 7999-00 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible
	$20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year
	All other practitioners (including physiotherapy): $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum
	100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs
	Coverage limited to lowest priced generic alternative
	$7.00 dispensing fee cap
Vision Care	100% coverage to $250 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000
	180 day trip maximum
	Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,000 / year maximum per person
Orthodontia	50% coverage to $1,250 / lifetime maximum per person

Division 7999-01 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $300 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,200 / year maximum per person
Orthodontia	50% coverage to $1,500 / lifetime maximum per person

Division 7999-05 - 100% Company Paid benefits

Benefit	**Coverage Summary**
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $350 maximum every 24 months per person
Hearing Aids	100% standard coverage to a maximum of $500 every 3 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,275 / year maximum per person
Major Restorative	50% coverage to $1,350 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 7999-91 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $300 maximum every 24 months per person includes eye exam
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,250 / year maximum per person
Major Restorative	50% coverage to $1,350 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 7999-92 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year Physiotherapist: No maximum All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative No dispensing fee cap
Vision Care	100% coverage to $200 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,000 / year maximum per person
Orthodontia	50% coverage to $1,000 / lifetime maximum per person

Division 7999-96 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year Physiotherapist: No maximum All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $200 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,000 / year maximum per person
Orthodontia	50% coverage to $1,000 / lifetime maximum per person

Division 7998-02 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $300 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,500 / lifetime maximum per person

Division 7998-04 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $350 maximum every 24 months per person includes eye exams
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,600 / year maximum per person
Major Restorative	50% coverage to $1,600 / year maximum per person
Orthodontia	50% coverage to $2,500 / lifetime maximum per person

Division 7998-10 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $375 maximum every 24 months per person includes eye exams
Hearing Aids	100% standard coverage every 3 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,625 / year maximum per person
Major Restorative	50% coverage to $1,600 / year maximum per person
Orthodontia	50% coverage to $2,500 / lifetime maximum per person

Division 7998-82 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year Physiotherapist: No maximum All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative
Vision Care	100% coverage to $200 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 7998-86 - 100% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year Physiotherapist: No maximum All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $200 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 7998-90 - 100% Company Paid benefits

Benefit	**Coverage Summary**
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year All other practitioners (including physiotherapy): $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $250 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,500 / lifetime maximum per person

Division 1983-00 – 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year All other practitioners (including physiotherapy): $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $250 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,000 / year maximum per person
Orthodontia	50% coverage to $1,250 / lifetime maximum per person

Division 1983-01 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $300 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,200 / year maximum per person
Orthodontia	50% coverage to $1,500 / lifetime maximum per person

Division 1983-11 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $350 maximum every 24 months per person
Hearing Aids	100% standard coverage to a maximum of $500 every 3 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,275 / year maximum per person
Major Restorative	50% coverage to $1,350 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 1983-94 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $300 maximum every 24 months per person includes eye exam
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,250 / year maximum per person
Major Restorative	50% coverage to $1,350 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 1983-96 - 15% Company Paid benefits

Benefit	**Coverage Summary**
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year Physiotherapist: No maximum All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $200 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,000 / year maximum per person
Orthodontia	50% coverage to $1,000 / lifetime maximum per person

Division 1983-98 - 15% Company Paid benefits

Benefit	**Coverage Summary**
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible
	$20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year
	Physiotherapist: No maximum
	All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum
	100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs
	Coverage limited to lowest priced generic alternative
	No dispensing fee cap
Vision Care	100% coverage to $200 maximum every 24 months per person
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000
	180 day trip maximum
	Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,000 / year maximum per person
Major Restorative	50% coverage to $1,000 / year maximum per person
Orthodontia	50% coverage to $1,000 / lifetime maximum per person

Division 3282-88 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year Physiotherapist: No maximum All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative No dispensing fee cap
Vision Care	100% coverage to $200 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 3282-86 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $300/calendar year Physiotherapist: No maximum All other practitioners: Various cost per visit and/or calendar year maximums
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $200 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,000 / lifetime maximum per person

Division 3282-90 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible
	$20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year
	All other practitioners (including physiotherapy): $500/calendar year
Hospital	100% Semi-Private coverage, unlimited maximum
	100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs
	Coverage limited to lowest priced generic alternative
	$7.00 dispensing fee cap
Vision Care	100% coverage to $250 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000
	180 day trip maximum
	Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,500 / lifetime maximum per person

Division 3282-02 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $300 maximum every 24 months per person
Hearing Aids	100% standard coverage every 5 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,500 / year maximum per person
Major Restorative	50% coverage to $1,500 / year maximum per person
Orthodontia	50% coverage to $2,500 / lifetime maximum per person

Division 3282-10 - 15% Company Paid benefits

Benefit	Coverage Summary
Life	$10,000 Paid Up Life (100% paid for by Company)
Extended Health Care	$10 Single Annual Deductible $20 Family Annual Deductible
Paramedical	Chiropractor: $350/calendar year Physiotherapist: $750/calendar year All other practitioners: $500/calendar year combined
Hospital	100% Semi-Private coverage, unlimited maximum 100% Private coverage, $5,000 / 5 years maximum (subject to Extended Health Care deductible)
Drugs	100% coverage, Paid Direct Drug Card - prescription drugs Coverage limited to lowest priced generic alternative $7.00 dispensing fee cap
Vision Care	100% coverage to $375 maximum every 24 months per person includes eye exams
Hearing Aids	100% standard coverage every 3 years
Out of Country	100% coverage for Emergency Care to a maximum $1,000,000 180 day trip maximum Referral coverage to maximum of $50,000
Basic Dental	100% coverage to $1,625 / year maximum per person
Major Restorative	50% coverage to $1,600 / year maximum per person
Orthodontia	50% coverage to $2,500 / lifetime maximum per person

Service Award and Retirement Bonus Provisions

London Hydro Inc. will pay bonus amounts upon the attainment of specific service levels. Service attainments and the corresponding bonus amounts are shown below:

Service Level Attained	Bonus Amount
5 years	$60
10 years	$110
15 years	$150
20 years	$250
25 years	$300
30 years	$400
35 years and above (5 year increments)	$450
Retirement	$500

Disability Plan Provisions

London Hydro Inc. shall continue the payment of medical premiums in Article 24:01 for twelve (12) months after expiration of the Corporation sick leave plan.

After twelve (12) months, further payments shall be prorated according to length of service as determined by the posted seniority list as follows:

- Less than five (5) years service - no further payment
- For each year of service over five (5) - six (6) months payment
- In no case shall payment be continued past age sixty-five (65).

When the employee is no longer eligible for Corporation payment of premiums, they may remain in the Corporation group and make across-the-counter payments to continue these benefits.

If payment of medical premiums can be secured from other sources, such as spouse's employment or premium assistance, the Corporation is not obligated for these payments.

APPENDIX E

Transition to International Financial Reporting Standards

This appendix contains information to enable the Company to disclose the impact of the transition to IFRS in its financial reports.

Accounting Policies

Transition Methodology

The Company has elected to adopt the "fresh start" exemption allowed under *IFRS 1 – First Time Adoption of International Financial Accounting Standards*. Under the "fresh start" exemption, any unamortized amounts[16] at 30 September 2010 as well as the difference in funded status at early measurement date (including 4th quarter contributions) and at transition date are immediately recognized at 01 January 2011 as a transition adjustment to retained earnings.

Recognition of Actuarial Gains and Losses

When reporting under IAS19, the Company has decided to recognize actuarial gains and losses immediately in other comprehensive income in the period in which they occur.

Past Service Costs

In accordance with IAS 19, the amortization of past service costs emerging from plan amendments is made on a linear basis over the average vesting period of the benefits granted for active members expected to receive benefits under the plan. If the benefits granted vest immediately then the full past service cost is recognised immediately.

Valuation Methods

The actuarial cost method and attribution of benefits to employee service are as described in the report for CICA 3461.

[16] Unamortized amounts include unamortized gains or losses, past service costs or credits and transitional asset or obligations that arose from the adoption of CICA 3461 in 2000. The sole exception is that any unamortized past service costs that have not yet vested continue to be amortized over that period that such benefits vest.

Principal Expense and Disclosure Information

Opening IFRS Balance Sheet

The net asset (liability) at 01 January 2011 under IAS 19, is $11,716,400.

Amounts Recognized in the Balance Sheet Under IAS 19	01.01.11
Benefit obligation	($11,716,400)
Fair value of plan assets	0
Excess (deficit)	**($11,716,400)**
Unamortized unvested past service costs (credits)	0
Net asset (liability) under IAS 19	**($11,716,400)**

The charge to retained earnings due to the transition to IAS 19 from CICA 3461 is $1,645,700 for the Plan and is determined as follows:

Reconciliation to IAS 19 from CICA 3461	01.01.11
Net asset /(liability) under CICA 3461	($10,070,700)
LESS	
Net asset /(liability) under IAS 19	($11,716,400)
Total charge (credit) to retained earnings	**$1,645,700**

Reconciliation to IAS 19 from CICA 3461	01.01.11
Unamortized transitional obligation (asset)	$0
Unamortized vested past service costs (credits)	0
Unamortized net actuarial loss (gain)	1,645,700
Difference in attribution period	0
Difference in scope of plans valued	0
Difference in funded status at early measurement date (including 4th quarter contributions) and transition date *01 January 2011*	0
Total charge (credit) to retained earnings	**$1,645,700**

Comparator Year IFRS Non-Pension Post Retirement Benefit Expense

The non-pension post retirement benefit cost under IAS 19 for the fiscal year ending 31 December 2011 is determined as follows.

Components of Non-Pension Postretirement Benefit Cost under IAS 19	Fiscal Year Ending 31.12.11
Amounts recognized in profit or loss:	
• Current service cost	$274,800
• Interest cost	629,700
• Expected return on plan assets	0
• Amortization of unvested past service cost (credit)	0
• Recognition of vested past service cost (credit)	0
• Amortization of net loss (gain)	0
• Curtailment loss (gain) recognized	0
• Settlement loss (gain) recognized	0
Total non-pension post retirement benefit cost/(credit) under IAS 19 recognized in profit or loss	**$904,500**
Amounts recognized in other comprehensive income:	
Actuarial loss (gain) immediately recognized	134,500
Total non-pension post retirement benefit cost/(credit) under IAS 19 recognized in OCI	**$134,500**

End of Comparator Year IFRS Balance Sheet

The net asset (liability) at 31 December 2011 under IAS 19, is $12,385,000.

Amounts Recognized in the Balance Sheet under IAS 19	31.12.11
Benefit obligation	($12,385,000)
Fair value of plan assets	0
Excess (deficit)	**($12,385,000)**
Unamortized unvested past service costs (credits)	0
Unamortized net actuarial loss (gain)	0
Net asset (liability) under IAS 19	**($12,385,000)**

Adjustment to Equity on Adoption of IFRS

The adjustments required on adoption of IFRS on 01 January 2011 are determined as follows:

Additional Adjustment to Equity on Adoption of IFRS	**Fiscal Year Ending 31.12.11**
Total non-pension post retirement benefit cost/(credit) under IAS 19 recognized in profit or loss	$904,500
PLUS	
Total non-pension post retirement benefit cost/(credit) under IAS 19 recognized in OCI	134,500
LESS	
Net periodic non-pension post retirement benefit cost under CICA 3461 for the period 01 January 2011 to 31 December 2011	939,900
Additional charge (credit) to equity	**$99,100**

Total Adjustment to Equity	01.01.12
Initial charge (credit) at 01 January 2011	$1,645,700
Additional charge (credit) at 31 December 2011	99,100
Charge (credit) to equity	**$1,744,800**

Other Benefits

Under IAS 19, the liability for medical and dental benefits while on LTD as at 31 December 2011 based on a discount rate of 4.4% per annum is $170,503. The liability for service awards and retirement allowances as at 31 December 2011 based on a discount rate of 4.4% per annum is $159,861. These liabilities should be recognized in expense resulting in a total additional expense for other benefits of $330,364 as at 31 December 2011 under IAS 19.

APPENDIX F

Employer Certification

With respect to the benefits included in the Report on Non-Pension Post Retirement Benefit Cost and Disclosure for the Fiscal Year Ending 31 December 2011 under CICA Section 3461 and Disclosure in Relation to the Transition to IAS 19 at 01 January 2011 of London Hydro Inc.'s Non-Pension Post Retirement Benefit Plan, I hereby certify that, to the best of my knowledge and belief:

- The membership data supplied to the actuary provides a complete and accurate description of all persons who are entitled to benefits under the terms of these Plans for service up to the date of the valuation, 30 September 2011.
- A copy of the plan documents and of all amendments made up to 31 December 2011 for these Plans were supplied to the actuary;
- All substantive commitments (as defined under CICA 3461) and constructive obligations (as defined under IAS 19) have been communicated to the actuary;
- Accounting policies adopted by the Company are those described in this report;
- The actuarial methods, amortization method and amortization periods to be used for the purposes of the valuation are those described in this report;
- Management's best-estimate assumptions for purposes of the valuation of the Plan and the extrapolation of the financial position of the Plan as of the fiscal year end 31 December 2011 are those described in this report; and
- All events subsequent to the valuation that may have an impact on the results of the valuation have been communicated to the actuary.

8 Feb 12.

Date

Signed

Mike Chase.

Name

Director of Finance.

Title

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APPENDIX 4D – KINECTRICS REPORT FOR LONDON HYDRO CONSORTIUM

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London Hydro, Woodstock Hydro & Chatham-Kent Hydro Useful Life of Assets

Kinectrics Inc. Report No: K-418027-RA-0001-R003

January 14, 2010

Kinectrics Inc.
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DISCLAIMER

London Hydro, Woodstock Hydro & Chatham-Kent Hydro
Useful Life of Assets
Kinectrics Inc. Report No: K-418027-RA-0001-R003

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Revision History

Revision Number	Date	Comments	Approved
R000	December 4, 2009	Initial Draft	N/A
R001	December 14, 2009	Finalized Draft	N/A
R002	December 22, 2009	Updated Finalized Draft (changes made to Cable Useful Life)	N/A
R003	January 14, 2010	Final Version	Y. Tsimberg

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1 Executive Summary

1.1 Introduction

Ontario's Local Distribution Companies (LDCs) are switching to International Financial Reporting Standards (IFRS) methodology. One of the "tenants" of IFRS is the time period assets are amortized over should align with their actual useful life.

LDCs typically own and operate a large number of assets that are divided into different asset categories, each with its own degradation mechanism and useful life range. Furthermore, some assets are comprised of several components that may have differing useful life than the assets themselves. To facilitate conversion to IFRS, LDCs need to ensure that a) they track all relevant asset categories and their components and b) that the amortization period for these is adequately aligned with actual LDC-specific useful lives.

This report reviews the useful lives of the assets, and their components that are applicable to London Hydro, Woodstock Hydro and Chatham-Kent Hydro (the Consortium). The useful life values are compiled from several different sources, namely, industrial statistics, research studies and reports (either by individuals or working groups such as CIGRE), and Kinectrics experience, all listed in *Section 32* of this Report. Useful lives of assets are dependent on a number of utilization factors, specifically time-base maintenance, operating practices and utilization (electrical loading). These factors are described in detail in *Section 1.4* of this report and are used to decide where the LDC-specific typical asset/components lives should be relative to the typical lives based on the industry data. It is also worth noting that the useful lives of assets do not generally follow standard distribution curves as 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 the Consortium. The typical parent system(s) to which the asset belongs is provided and these "parent" systems are: *Overhead Lines* (OH), *Municipal Stations* (MS), *Distribution Transformers* (DT), *Underground Systems* (UG) and *Monitoring and Control System* (S). The long term degradation mechanism is described for each asset category and when applicable assets are sub-categorized into components. Components are included when their cost is material enough and, at the same time, could be replaced without a need to replace the whole asset. 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
- Potential for impact from LDC-specific operating practices and utilization
- Functional Requirements

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 Consortium, but also that it addresses the specific needs related to the IFRS review. The procedure is as follows:

- The initial list of assets and components was produced by the Consortium to Kinectrics for review.

- 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.

- The intermediate list was reviewed jointly by Consortium and Kinectrics to derive a “final” list.

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

- This Draft Report was reviewed by Consortium and their feedback was incorporated in the Final Report.

1.4 Definition of Terms

1.4.1 *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.

1.4.2 *Component*

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

- Its replacement value is significant enough, relative to the asset value.
- A need to replace the component does not necessarily warrant replacing the entire asset.

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.

1.4.3 *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. The majority of the units within this class will perform as required for at least 20 years and likewise the majority of the units will not 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 various utilization factors including mechanical stress, electrical loading, and environmental conditions and operating practices.

1.4.4 *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.

1.4.5 *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.

1.4.6 *Potential for impact from LDC-specific operating practices and utilization*

For the purpose of this report, stress that impacts the assets refers Operating Practices and Electrical Loading utilization factors. Operating practices refers to how frequently an asset is subject to operating procedure (automatic or manual) that impacts its useful life, e.g. reclosers operations. This is a reflection of the operability of the system. Electrical loading refers to either constant loading that creates long term degradation or temporary overloading that may causes a severe degradation. It includes the asset's tolerance to over-loading.

1.4.7 *Functional Requirements*

For the purposes of this report, the only functional requirement being considered is assets that may become obsolete. This refers to assets in which the functional requirements are not being met even though the component may still be able to perform as originally designed. For the purposes of useful life both degradation and obsolescence have been taken into account. For example, substation relays have a maximum useful life of 15 years, as they become obsolete after that time. However, that particular device could have a maximum life of up to 25 years based on degradation alone.

1.5 Summary of Findings

Table 1-1 summarizes useful and typical lives, time based maintenance schedules, and impact of stress for Consortium assets.

Table 1-1 Summary of Componentized Assets

Sect.	Parent*	Asset Category	Componentization		Useful Life (years)			Maint. Type**	Maint. Sched. (years)	Impact of Operating Practices	Impact of Electrical Loading	Funct. Req.	References
					MIN	TYP	MAX						
2	OH	Wood Poles	Pole		40	44	80	RI	15				[1]-[14], [46]
			Cross Arm	Wood	20	40	50						
				Composite	40	60	80						
				Steel	20	70	100						
			Bracket	Galvanized Steel	20	40	50						
			Insulator	Composite	25	45	50						
				Porcelain	40	40	50						
			Anchors & Guying		20	40	50						
3	OH	Concrete Poles	Pole		50	60	80	RI	15				[1]-[14], [46]
			Componentization: refer to (2.2-2.5) Wood Poles										
4	OH	Steel Poles	Pole		60	60	80	RI	15				[1]-[14]
			Componentization: refer to (2.2-2.5) Wood Poles										
5	OH	Composite Poles	Pole		50	70	100	N/A	N/A				[1]-[14]
			Componentization: refer to (2.2-2.5) Wood Poles										
6	OH	Manual Overhead Switches			30	50	60	RTM	2	✓	✓		[6]

* OH = Overhead Lines MS=Municipal Stations DT = Distribution Transformers UG=Underground Systems S=Monitoring and Control Systems
** RI=Routine Inspection RTM=Routine Testing/Maintenance N/A=Not Applicable

Sect.	Parent*	Asset Category	Componentization		Useful Life (years)			Maint. Type**	Maint. Sched. (years)	Impact of Operating Practices	Impact of Electrical Loading	Funct. Req.	References
					MIN	TYP	MAX						
7	OH	Local Motorized Overhead Switches	Switch		30	50	60	RTM	2	✓	✓		[6]
			Motor		15	20	20						
8	OH	Remote Automated Overhead Switches	Switch		30	50	60	RTM	2	✓	✓	✓	[15]-[16]
			Motor		15	20	20						
			RTU		15	20	30						
9	OH	Reclosers	Oil		30	42	60	RTM	10	✓	✓		[5],[6], [15],[16]
			Solid Dielectric		30	40	60						
			SF6		30	40	60						
10	OH	Conductors (Primary / Secondary)	ACSR		50	60	77	N/A	N/A	✓	✓		[5], [17]
			AAC		50	60	77						
			Copper		50	60	77						
11	MS	MS Power Transformers	Winding		32	45	55	RTM	2	✓	✓		[18]-[24]
			Tap Changer		20	30	60						
			Bushing		10	15	25						
12	MS	MS Switchgear	Breaker	Oil	30	42	60	RTM	6	✓	✓		[1],[6], [25]-[26]
				Vacuum	30	40	60						
				Air Magnetic	25	40	60						
			Switchgear Assembly		40	50	60						
13	MS	Bus Work & Steel Structure	Steel Structure		35	50	100	N/A	N/A				[1]
			Busbar		30	60	60						
14	MS	Substation Relays	Electromechanical		20	30	50	N/A	N/A	✓	✓	✓	[1], [18], [39]-[41], [47]
			Solid State		10	30	50						
			Digital[1]		10	15	20						

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1 – *(14.3) Usually replace because of obsolescence but max life could be up to 25 years*

Sect.	Parent*	Asset Category	Componentization		Useful Life (years) MIN	TYP	MAX	Maint. Type**	Maint. Sched. (years)	Impact of Operating Practices	Impact of Electrical Loading	Funct. Req.	References
15	MS	Batteries	Battery Bank[2]		10	15	15	RTM	1	✓	✓		[6], [42]-[44]
			Charger		20	20	30						
16	MS	Distribution Buildings	Structure		30	50	80	RI	1				[19]
			Roof		15	20	30						
			Fence		30	35	60						
17	DT	Pole Top Transformers			30	40	60	N/A	N/A		✓		[5]
18	DT	Pad-Mounted Transformers[3]			30	40	40	N/A	N/A	✓	✓		[4]-[6]
19	DT	Network Transformer	Protectors[4]		20	35	40	RI	2	✓	✓		[1],[5], [38]
			Transformer Unit		20	35	50						
20	UG	Submersible Transformer			25	35	40	RI	2	✓	✓		[4]-[6]
21	UG	Primary Cables	PILC		70	75	80	N/A	N/A		✓		[6],[27], [28], [48]-[50]
			XLPE	Direct Buried	10	15	20						
				In Duct	20	20	25						
			TR-XLPE	Direct Buried	20	25	25						
				In Duct	40	40	60						
22	UG	Secondary Cables	XLPE[5]	Direct Buried	20	30	35	N/A	N/A		✓		[6],[27], [28],[53]
				In Duct	40	40	60						
23	UG	Network Vault	Overall		40	60	80	RTM	3				[1],[5], [38]
			Roof		20	25	40						
24	UG	Submersible Vault	Overall		40	60	80	RTM	3	✓	✓		[1],[5], [38]
			Roof		20	25	40						

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** RI=Routine Inspection RTM=Routine Testing/Maintenance N/A=Not Applicable

2 - *(15.1) For N-C battery banks, the useful life could be longer* 3 - *(18) DSC requires RI every 3 years, this should increase their typical life in Ontario*

4 - *(19.1) If the Protector is waterproof, max typical life could be 50 years* 5 – *(22) Assuming the use of insulation materials (i.e. TR-XLPE)*

Sect.	Parent*	Asset Category	Componentization		Useful Life (years) MIN	TYP	MAX	Maint. Type**	Maint. Sched. (years)	Impact of Operating Practices	Impact of Electrical Loading	Funct. Req.	References
25	UG	Pad-Mounted Switchgear	Air Insulated		20	20	40	RI	3				[29]-[31]
			Gas Insulated		30	30	50						
			Solid Dielectric		30	30	50						
26	UG	Cable Chamber	Overall		50	60	80	RTM	3				[5],[6], [32]
			Roof		20	25	40						
27	UG	Transformer & Switchgear Foundations			30	60	80	RTM	3				[5],[6]
28	UG	Duct Bank			30	50	80	N/A	N/A				[5],[6], [33]
29	S	Meters	Primary	OH	20	30	50	N/A	N/A			✓	[5],[34], [35],[52]
				Pad-mounted	20	30	50						
			Residential		20	30	45						
			Industrial/ Wholesale	Electromechanical	20	30	60						
				Interval	10	15	15						
			PTs		30	45	50						
			CTs		30	45	50						
30	S	Smart Meters	Meters		15	15	20	N/A	N/A			✓	[5], [36]
			Computer	Hardware	*Refer to (32.3) Admin Buildings*								
				Software									
			Data Concentrator (Collector)		10	20	20						
			Repeater		5	10	15						
			Communication Tower		35	63	100						
31	S	SCADA RTU			15	20	30	N/A	N/A	✓		✓	[1], [15], [16],[37]

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** RI=Routine Inspection RTM=Routine Testing/Maintenance N/A=Not Applicable

Sect.	Parent*	Asset Category	Componentization		Useful Life (years) MIN	Useful Life (years) TYP	Useful Life (years) MAX	Maint. Type**	Maint. Sched. (years)	Impact of Operating Practices	Impact of Electrical Loading	Funct. Req.	References
32	N/A	Administrative Buildings	Building	Mechanical	12	20	30	RI	1				[19], [45]
				Civil	30	50-60	100						
				Electrical	12	20	40						
				Parking	15	20	30						
			Roof		15	20	30						
			Fence		30	35	60						

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** RI=Routine Inspection RTM=Routine Testing/Maintenance N/A=Not Applicable

2 Wood Poles

The asset referred to in this category is the fully dressed wood pole ranging in size from 30 to 75 feet. This includes the wood pole, cross arm, bracket, insulator, and anchor & guys. Wood poles are typically the most common form of support for overhead distribution feeders and low voltage secondary lines.

The most significant component of this asset 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 to be a part of the Overhead Lines asset grouping.

2.3 Useful Life and Typical Life

The overall useful life of a wood pole is in the range of 40 to 80 years; the typical life is 44 years.

This asset also has several major components, each with a different useful life:

- Cross Arm (Wood, Composite, Steel)
- Bracket (Galvanized Steel)
- Insulator (Composite, Porcelain)
- Anchor and Guying

2.3.1 *Cross Arm*

The useful life of a <u>wood</u> cross arm is in the range of 20 to 50 years; the typical life is 40 years.

The useful life of a <u>composite</u> cross arm is in the range of 40 to 80 years; the typical life is 60 years.

The useful life of a <u>steel</u> cross arm is in the range of 20 to 100 years; the typical life is 70 years.

2.3.2 *Bracket (Galvanized Steel)*

The useful life of an aluminum bracket component ranges from 20 to 50 years, with a typical value of approximately 40 years.

2.3.3 *Insulator*

The useful life of a <u>composite</u> insulator is in the range of 25 to 50 years; the typical life is 45 years.

The useful life of a <u>porcelain</u> insulator is in the range of 40 to 50 years, with a typical life of 40 years.

2.3.4 *Anchors and Guying*

The useful life of anchors and guying is in the range of 20 to 50 years; the typical life is 40 years.

2.4 Time Based Maintenance Intervals

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

2.5 Utilization Factors

Wood poles asset category is not subject to the Utilization Factors discussed in this report.

2.6 Functional Requirements

Wood poles asset category is not subject to obsolescence.

3 Concrete Poles

This asset category includes the concrete pole with the same components as for the wood poles, namely cross arm, bracket, insulator, and anchor. These poles range in size from 35 to 80 feet, with the typical pole being 60 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 to be a part of the Overhead Lines assets grouping.

3.3 Useful Life and Typical Life

The useful life range of the concrete pole component is 50 to 80 years; the typical life is 60 years.

For other componentization useful life (cross arm, bracket, insulator, and anchor), please refer to *Section 2.3*.

3.4 Time Based Maintenance Intervals

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

3.5 Utilization Factors

Concrete poles asset category is not subject to the Utilization Factors discussed in this report.

3.6 Functional Requirements

Concrete poles asset category is not subject to obsolescence.

4 Steel Poles

This asset category includes the directly buried steel pole, cross arm, bracket, insulator, and anchor.

4.1 Degradation Mechanism

The degradation of directly buried steel poles is mainly due to steel corrosion in-ground. In-ground situations are vastly different because of the wide local variations in soil chemistry, moisture content and conductivity that will affect the way coated or uncoated steel will perform in the ground.

There are two issues that determine the life of buried steel. The first is the life of the protective coating and the second is the corrosion rate of the steel. The item can be deemed to have failed when the steel loss is sufficient to prevent the steel performing its structural function. Where polymer coatings are applied to buried steel items, the failures are rarely caused by general deterioration of the coating. Localized failures due to defects in the coating, pin holing or large-scale corrosion related to electrolysis are common causes of failure in these installations.

Metallic coatings, specifically galvanizing, and to a lesser extent aluminum, fail through progressive consumption of the coating by oxidation or chemical degradation. The rate of degradation is approximately linear, and with galvanized coatings of known thickness, the life of the galvanized coating then becomes a function of the coating thickness and the corrosion rate.

4.2 System Hierarchy

Steel poles are considered a part of the Overhead Lines asset grouping.

4.3 Useful Life and Typical Life

The useful life of steel poles is in the range of 60 to 80 years; the typical life is 60 years.

For other componentization useful life (cross arm, bracket, insulator, and anchor), please refer to *Section 2.3*.

4.4 Time Based Maintenance Intervals

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

4.5 Utilization Factors

Steel poles asset category is not subject to the Utilization Factors discussed in this report.

4.6 Functional Requirements

Steel poles asset category is not subject to obsolescence.

5 Composite Poles

This asset category includes the composite pole, cross arm, bracket, insulator, and anchor. At Consortium the composite poles are fiberglass.

5.1 Degradation Mechanism

The most significant component in this class is the composite pole itself. The major degradation of composite poles is ultra violet (UV) degradation. It represents an attack from ultra-violet radiation, which might result in crack or disintegration in composite poles. It is a common problem in products exposed to sunlight. Continuous exposure is a more serious problem than intermittent exposure, since attack is dependent on the extent and degree of exposure. In fiber products like composite poles, useful life will be shortened because the outer fibers will be attacked first, and will easily be damaged by abrasion. This will end up with fiber blooming and fading.

5.2 System Hierarchy

Composite poles are considered to be a part of the Overhead Lines assets grouping.

5.3 Useful Life and Typical Life

The useful life range of the composite pole component is 50 to 100 years; the typical life is 70 years.

For other componentization useful life (cross arm, bracket, insulator, and anchor), please refer to *Section 2.3*.

5.4 Time Based Maintenance Intervals

Composite poles are not subject to planned maintenance.

5.5 Utilization Factors

Composite poles asset category is not subject to the Utilization Factors discussed in this report.

5.6 Functional Requirements

Composite poles asset category is not subject to obsolescence.

6 Manual Overhead Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang.

6.1 Degradation Mechanism

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

6.2 System Hierarchy

Overhead Switches asset category belongs to the Overhead Lines assets grouping.

6.3 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.

6.4 Time Based Maintenance Intervals

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

6.5 Utilization Factors

Manual overhead switches are impacted by operating practices and electrical loading utilization factors.

6.6 Functional Requirements

Manual overhead switches category is not subject to obsolescence.

7 Local Motorized Overhead Switches

This asset class consists of overhead line three-phase, gang operated switches and a motor. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism is controlled by a motor.

7.1 Degradation Mechanism

Like the remotely operated switch, the main degradation processes associated with local motorized overhead 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.

7.2 System Hierarchy

Local Motorized Overhead Switches category belongs to the Overhead Lines assets grouping.

7.3 Useful Life and Typical Life

The local motorized overhead switch can be componentized into two components:

- Switch
- Motor

7.3.1 *Switch*

The useful life of local motorized switches is in the range of 30 to 60 years; the typical life is 50 years.

7.3.2 *Motor*

The useful life of the motor of local motorized switches is in the range of 15 to 20 years; the typical life is about 20 years.

7.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for local motorized switches is every two years.

7.5 Utilization Factors

Local motorized overhead switches are impacted by operating practices and electrical loading utilization factors.

7.6 Functional Requirements

Local motorized overhead switches asset category is not subject to obsolescence.

8 Remote Automated Overhead Switches

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 to 900 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. This component also consists of a remote terminal unit (RTU) component.

8.1 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.

8.2 System Hierarchy

Remote Automated Overhead switches asset category belongs to the Overhead Lines assets grouping.

8.3 Useful Life and Typical Life

The remote automated overhead switch can be componentized into three components:

- Switch
- Motor
- Remote Terminal Unit (RTU)

8.3.1 *Switch*

The useful life of remote automated switches is in the range of 30 to 60 years; the typical life is 50 years.

8.3.2 *Motor*

The useful life of a motor is in the range of 15 to 20 years; the typical life is 20 years.

8.3.3 *Remote Terminal Unit (RTU)*

The useful life of an RTU is in the range of 15 to 30 years; the typical life is 20 years.

8.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for remote automated overhead switches is every two years.

8.5 Utilization Factors

Remote automated overhead switches are impacted by operating practices and electrical loading utilization factors.

8.6 Functional Requirements

Remote automated overhead switches are subject to obsolescence.

9 Reclosers

This asset class consists of light duty circuit breakers equipped with interrupters that use controllers. This is where the breaking and making of fault current takes place. The interrupters use oil of vacuum as the insulating agent. The controllers are either hydraulic or electric. It is designed for single phase or three phase use, depending on the model.

9.1 Degradation Mechanism

The degradation processes associated with reclosers involves the effects of making and breaking fault current, the mechanism itself and deterioration of components. The effects of making and breaking fault current affect suppression devices as well as the contacts, the oil, and the arc control. The degradation of these devices depends on the prevailing fault, if it is well below the rated capability of the recloser, the deteriorating effects will be small. For the mechanism itself, deterioration or mal-operation of the mechanism causes deterioration during operation. Typically lack of use, corrosion and poor lubrication are the main causes of mechanism mal-function. For deterioration, exposure to weather is a potentially significant degradation process – primarily corrosion of the tank and other metallic components and deterioration of bushings.

9.2 System Hierarchy

Recloser asset category belongs to the Overhead Lines assets grouping.

9.3 Useful Life and Typical Life

Recloser breakers can be categorized into three types and the useful life is dependent on the type:

- Oil
- Solid Dielectric
- Sulfur Hexafluoride Gas (SF6)

9.3.1 *Oil*

The useful life of oil breakers is in the range of 30 to 60 years; the typical life is 42 years.

9.3.2 *Solid Dielectric*

The useful life of solid dielectric breakers is in the range of 30 to 60 years; the typical life is 40 years.

9.3.3 *Sulfur Hexafluoride Gas (SF6)*

The useful life of SF6 breakers is in the range of 30 to 60 years; the typical life is 40 years.

9.4 Time Based Maintenance Intervals

The typical routine testing/maintenance schedule for the breaker component of reclosers is every ten years.

9.5 Utilization Factors

Reclosers are impacted by operating practices and electrical loading utilization factors.

9.6 Functional Requirements

Recloser asset category is not subject to obsolescence.

10 Conductors (Primary and Secondary)

Overhead conductors along with structures that support them constitute overhead lines or feeders that distribute electrical energy either directly to large customers or from Municipal Stations via distribution transformers to the end users. These conductors are sized to carry a specified maximum current and to meet other design criteria, i.e. mechanical loading.

The overhead conductors typically used by the Consortium are aluminum conductor steel reinforced (ACSR), all aluminum conductor (AAC), and copper.

10.1 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.

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

The degradation of copper wire is mostly due to corrosion. Oxidization gives copper a high resistance to corrosion. Derivatives of chlorine and sulfur contained in coastal atmospheres start the oxidation by forming a blackish or greenish film. The film is very dense, has low solubility, high electric resistance and high resistance to the chemical attack and to corrosion. Despite this, mechanical vibrations, abrasion, erosion and thermal variations may cause fissures and faults in this layer. When this happens, the metal is uncovered and corrosion may occur. Also electrolytes with low Cl contents could enter, causing a dislocation of the passivity. This may also be the result of a deficit of oxygen which would make the area anodic.

10.2 System Hierarchy

The Wire asset category belongs to the Overhead Lines assets grouping.

10.3 Useful Life and Typical Life

The useful life of conductors is dependent on the conductor type:

- Aluminum Conductor Steel Reinforced (ACSR)
- All Aluminum Conductor (AAC)
- Copper

10.3.1 *Aluminum Conductor Steel Reinforced (ACSR)*

The useful life of ACSR conductors in the range of 50 to 77 years; the typical life is 60 years.

10.3.2 *All Aluminum Conductor (AAC)*

The useful life of AAC conductors in the range of 50 to 77 years; the typical life is 60 years.

10.3.3 *Copper*

The useful life of copper conductors in the range of 50 to 77 years; the typical life is 60 years.

10.4 Time Based Maintenance Intervals

Conductors are not subject to planned maintenance.

10.5 Utilization Factors

Conductors are impacted by electrical loading utilization factors.

10.6 Functional Requirements

Conductors asset category is not subject to obsolescence.

11 MS Power Transformers

Substation power transformers at distribution stations typically step down voltage to distribution levels. Ratings typically range from 5 MVA to 30 MVA. The Consortium typically uses Substation Power Transformers rated 20/33.3 MVA.

11.1 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.

11.2 System Hierarchy

MS Power Transformer asset category belongs to the Municipal Stations assets grouping.

11.3 Useful Life and Typical Life

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

- Winding
- On Load Tap Changer
- Bushing

11.3.1 *Winding*

The useful life of windings is 32 to 55 years; the typical life is 45 years.

11.3.2 *On Load Tap Changer*

The useful life range of tap changers is 20 to 60 years; the typical life is 30 years.

11.3.3 *Bushing*

The useful life range of the bushing is 10 to 25 years; the typical life is 15 years.

11.4 Time Based Maintenance Intervals

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

11.5 Utilization Factors

MS power transformers are impacted by operating practices and electrical loading utilization factors.

11.6 Functional Requirements

MS power transformers asset category is not subject to obsolescence.

12 MS Switchgear

The switchgear asset category can be classified in three types: oil, vacuum, and air magnetic switchgear. The gear also is compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and bus-bars associated with each cell.

12.1 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). Degradation of the breaker used is also a factor.

12.2 System Hierarchy

Switchgear asset category belongs to the Municipal Stations assets grouping.

12.3 Useful Life and Typical Life

The overall useful life range of the breaker itself is dependent on the component, each of which has its own useful and typical life:

- Breaker (Oil, Vacuum, Air Magnetic)
- Switchgear Assembly

12.3.1 *Breaker*

The useful life range of oil type breaker in air insulated switchgear is 30 to 60 years; typical life is 42 years.

The useful life range of vacuum type breaker in air insulated switchgear is 30 to 60 years; typical life is 40 years.

The useful life range of air magnetic type breaker in air insulated switchgear is 25 to 60 years; typical life is 40 years.

12.3.2 *Switchgear Assembly*

The useful life range of switchgear assembly is 40 to 60 years; typical life is 50 years.

12.4 Time Based Maintenance Intervals

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

12.5 Utilization Factors

MS switchgear is impacted by operating practices and electrical loading utilization factors.

12.6 Functional Requirements

MS Switchgear is subject to obsolescence.

13 Bus Work and Steel Structure

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.

13.1 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.

Rigid busbar degradation is mainly caused by thermal and mechanical stresses.

13.2 System Hierarchy

Bus Work and Steel Structures asset category belongs to the Municipal Stations assets grouping.

13.3 Useful Life and Typical Life

This asset group can be componentized into the following:

- Steel Structures
- Rigid Busbars

13.3.1 *Steel Structures*

The useful life of steel towers is in the range of 35 to100 years and the typical life is 50 years.

13.3.2 *Rigid Busbars*

The useful life range of rigid busbars is 30 to 60 years and the typical life is 60 years.

13.4 Time Based Maintenance Intervals

Bus Work and Steel Structures are not subject to planned maintenance.

13.5 Utilization Factors

Bus work and steel structure asset category is not subject to the Utilization Factors discussed in this report.

13.6 Functional Requirements

Bus work and steel structure asset category is not subject to obsolescence.

14 Substation Relays

This asset of substation relays is classified into of two types, electromechanical and digital. The function of these relays is to increase long term reliability. The protection relays work to detect and isolate faults on the system by opening and closing the circuit breakers.

14.1 Degradation Mechanism

The standard electromechanical relay consists of 3 sub-components:

- Relay coils
- Relay contacts
- Relay moving parts

Degradation on relay coils is mainly a thermal aging issue due to continuous energization or elevated cabinet temperatures. Excessive heat generated by coil or associated components may cause the coil to burn out or adversely affect other nearby components or components within the relay or nearby (e.g. chemical breakdown of varnishes causing contact contamination, or change in component dimensions).

Degradation of relay contacts is due to the following factors:

- Contact oxidation
- Contact welding or pitting due to excessive current
- Chemical corrosion

In the case of degradation of relay moving parts, such as wear of moving parts like spring/armature, the major contributing factor is the wear after numerous switching cycles.

As a consequence, the failure mode of an electromechanical relay can be:

- Failure to actuate when commanded
- Actuates without command
- Does not make or break current
- Failure to carry current
- High contact resistance
- Set-point shift
- Time delay shift

To assess the health status of an electromechanical relay, the following condition parameters are studied:

- Operating mechanism, including contact, coil, spring, insulation, connection and component replacement

- Recalibration, including recalibration record and relay functionality (e.g., over current, distance etc.)
- Reliability, including mal-operation count, loading and age

The standard digital relay consists of 3 major sub-components:

- Input sampling/filtering circuit
- Data processing module
- Software

Physical degradation of digital relays happen on hardware part of digital relays. Compared to solid state relays, digital relays are not sensitive to ambient environment. The major contributing factor of degradation is the electrical environment, i.e. inrush transient. Since digital relays have built-in self-supervision system, the settings with perfect long time stability is guaranteed.

The failure mode of a digital relay can be:

- Fail to trip because communication port is held by defective external equipment
- Mal-function due to hardware/firmware/software version mismatch
- Mal-function due to software design flaw causing software latched by external EMI interference
- On strike due to power supply failure

To assess the health status of a digital relay, the following condition parameters are studied:

- Operating mechanism, including power supply, insulation, connection
- Recalibration, including recalibration record and relay functionality (e.g., overcurrent, distance etc.)
- Reliability, including mal-operation count, loading and age

14.2 System Hierarchy

Substation Relays asset category belongs to the Municipal Stations assets grouping.

14.3 Useful Life and Typical Life

This asset is classified into three types, each of which has a different useful life:

- Electromechanical
- Solid State
- Digital

14.3.1 *Electromechanical*

The useful life range of the electromechanical type is 20 to 50 years; the typical life is 30 years.

14.3.2 *Solid State*

The useful life range of the solid state type is 10 to 50 years; the typical life is 30 years.

14.3.3 *Digital*

The useful life range of the digital type is 10 to 20 years; the typical life is 15 years. This type of substation relay is usually replaced because of obsolescence; however, the maximum life could potentially be up to 25 years.

14.4 Time Based Maintenance Intervals

Protection and control relays are not subject to planned maintenance.

14.5 Utilization Factors

Substation relays are impacted by operating practices and electrical loading utilization factors.

14.6 Functional Requirements

Substation relays are subject to obsolescence.

15 Batteries

Station battery systems are critical to the safe and efficient operation of transformer cooling, switchgear and protection & control. Maintaining batteries in a condition capable of delivering the necessary energy as required is essential.

Batteries can be componentized into two components: the battery bank and the charger. Battery banks consist of multiple individual cells. For the purposes of this report, these are lead-acid battery banks. Battery chargers are relatively simple electronic devices that have a high degree of reliability and a significantly longer lifetime than the battery banks.

15.1 Degradation Mechanism

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.

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. 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. The ability to detect significant deterioration and pre-empt battery failure is especially critical if monitoring and alarm systems are not installed.

Historically, battery end-of-life was determined mainly by a number of factors including age, appearance (indication of physical deterioration) and the history of specific gravity and cell voltage measurements. Presently, the battery load test is now considered the “best” indicator of battery condition. This test is now used to identify and confirm the condition of suspect batteries identified from the previous tests.

Battery chargers are also critical to the satisfactory performance of the whole battery system. 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.

For battery chargers, diagnostic testing programs are coordinated with the battery maintenance program. This involves a number of functional tests and each test has a defined TP/TF criteria. Failure of any functional test may lead to further investigations or consideration of replacement.

Due to the critical functionality of batteries, most utilities take a conservative approach towards battery replacement: any significant evidence of battery deterioration usually leads to decisions to replace the battery.

15.2 System Hierarchy

Batteries asset category belongs to the Municipal Stations assets grouping.

15.3 Useful Life and Typical Life

This asset is classified into two major components, each of which has a different useful life:

- Battery Bank
- Charger

15.3.1 *Battery Bank*

The useful life range of the battery bank component is 10 to 15 years; the typical life is 15 years. This is the useful life for lead-acid battery banks. For N-C battery banks, the useful life could be longer.

15.3.2 *Charger*

The useful life range of the charger component is 20 to 30 years; the typical life is 20 years.

15.4 Time Based Maintenance Intervals

The typical routine testing/maintenance interval for this asset class is every year.

15.5 Utilization Factors

Batteries are impacted by operating practices and electrical loading utilization factors.

15.6 Functional Requirements

Batteries asset category is not subject to obsolescence.

16 Distribution Buildings

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the building structure itself, the roof and fence.

16.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements
- Environmental concerns
- Functional requirements

Buildings are a very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life. Rather impacts such as environmental rain, wind and snow storms contribute highly to the degradation of buildings.

Also, since the foundation materials typically consist of reinforced concrete designed to consider environmental elements including soil conditions and climate. Landscaping is used to control soil erosion, maintain site cleanliness and facilitate an efficient and safe work environment.

Preventative maintenance helps ensure long-term integrity of buildings. This type of maintenance should be done on a regular basis. As well the occasional refurbishment of doors, windows and roofs helps with the viability of the building.

The building roof is the most susceptible to degradation due to environmental factors. The roof is typically level and composed of tar and an aggregate that is designed to keep the wind from wearing at the tar. Nevertheless, the roof is still susceptible to environmental degradation and if not sealed properly can become a source of flooding. The maintenance of the roof is generally the largest undertaking for buildings.

16.2 System Hierarchy

Distribution building asset category belongs to the Municipal Stations assets grouping.

16.3 Useful Life and Typical Life

This asset has three major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Structure
- Roof
- Fence

16.3.1 *Structure*

The useful life of the structure component of the building can be in the range of 30 to 80 years, with a typical life of 50 years.

16.3.2 *Roof*

The useful life of the roof can be in the range of 15 to 30 years, with a typical life of 20 years.

16.3.3 *Fence*

The useful life range of the fence is 30 to 60 years, with a typical life of 35 years.

16.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is every year.

16.5 Utilization Factors

The distribution buildings asset category is not subject to the Utilization Factors discussed in this report.

16.6 Functional Requirements

Buildings asset category is not subject to obsolescence.

17 Pole Top Transformers

Distribution pole top transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

17.1 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.

17.2 System Hierarchy

The Pole Top Transformer asset category belongs to the Distribution Transformers assets grouping.

17.3 Useful Life and Typical Life

The useful life of the pole top transformer is in the range of 30 to 60 years, with an average value close to 40 years.

17.4 Time Based Maintenance Intervals

Pole top transformers are not subject to planned maintenance.

17.5 Utilization Factors

Pole top transformers are impacted by electrical loading utilization factors.

17.6 Functional Requirements

Pole top transformers asset category is not subject to obsolescence.

18 Pad-Mounted Transformers

Pad-Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid.

18.1 Degradation Mechanism

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

18.2 System Hierarchy

Pad-Mounted Transformers asset category belongs to the Distribution Transformers asset grouping.

18.3 Useful Life and Typical Life

The useful life range of pad mounted distribution transformers are 30 to 40 years; the typical life is 40 years. The Distribution System Code (DSC) requires a routine inspection every three years; this should increase the typical life of pad-mounted transformers in Ontario.

18.4 Time Based Maintenance Intervals

Pad-Mounted Transformers are not subject to planned maintenance.

18.5 Utilization Factors

Pad-mounted transformers are impacted by operating practices and electrical loading utilization factors.

18.6 Functional Requirements

Pad-mounted transformers asset category is not subject to obsolescence.

19 Network Transformers

Network transformers are special purpose distribution transformers, designed and constructed for successful operation in a parallel mode with a large number of transformers with similar characteristic. 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.

19.1 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.

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:

- 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

19.2 System Hierarchy

Network Transformers asset category belongs to the Distribution Transformers asset grouping.

19.3 Useful Life and Typical Life

This asset class can be componentized into the following:

- Protector
- Transformer

19.3.1 *Protector*

The useful life range of the protector, assuming it is not waterproof enclosed is 20 to 40 years; typical life is 35 years. If the protector is waterproof, maximum useful life could be 50 years.

19.3.2 *Transformer*

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

19.4 Time Based Maintenance Intervals

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

19.5 Utilization Factors

Network transformers are impacted by operating practices and electrical loading utilization factors.

19.6 Functional Requirements

Network transformers asset category is not subject to obsolescence.

20 Submersible Transformers

Submersible transformers typically employ sealed tank construction and are liquid filled with mineral insulating oil.

20.1 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 has strong effects. In general, a combination of condition, age, and load based criteria is commonly used to determine the useful remaining life.

20.2 System Hierarchy

Submersible Transformers asset category belongs to the Distribution Transformers asset grouping.

20.3 Useful Life and Typical Life

The useful life range of vault distribution transformers is 25 to 40 years; the typical life is 35 years.

20.4 Time Based Maintenance Intervals

Distribution Transformers are not subject to planned maintenance

20.5 Utilization Factors

Submersible transformers are impacted by operating practices and electrical loading utilization factors.

20.6 Functional Requirements

Submersible transformers asset category is not subject to obsolescence.

21 Primary Cables

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 Consortium uses three cable types: paper insulated lead covered (PILC), cross linked polyethylene (XLPE) cable and tree retardant cross linked polyethylene (TR-XLPE) cable. XLPE and TR-XLPE underground cable can be installed in ducts it can also be directly buried.

21.1 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.

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.

TR-XLPE cables avoid degradation caused by water treeing. 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.

21.2 System Hierarchy

Underground Primary Cables asset category belongs to the Underground Systems assets grouping.

21.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type:

- Paper Insulated Lead Covered (PILC)
- Cross Linked Polyethylene (XLPE) (Direct Buried, In Duct)
- Tree Retardant (TR-XLPE) (Direct Buried, In Duct)

21.3.1 *Paper Insulated Lead Covered (PILC)*

The useful life range of PILC cable is 70 to 80 years; the typical life is 75 years.

21.3.2 *Cross Linked Polyethylene (XLPE)*

The useful life range of direct buried XLPE cable is 10 to 20 years; the typical life is 15 years.

The useful life range of in duct XLPE cable is 20 to 25 years; the typical life is 20 years.

21.3.3 *Tree Retardant (TR-XLPE)*

The useful life range of direct buried TR-XLPE cable is 20 to 25 years; the typical life is 25 years.

The useful life range of in duct TR-XLPE cable is 40 to 60 years; the typical life is 40 years.

21.4 Time Based Maintenance Intervals

Underground Primary Cables are not subject to planned maintenance.

21.5 Utilization Factors

Primary cables are impacted by electrical loading utilization factors.

21.6 Functional Requirements

Primary cables asset category is not subject to obsolescence.

22 Secondary Cables

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. Secondary underground cables are used to supply customer premises. The Consortium uses two secondary cable types: cross linked polyethylene (XLPE) cable and tree retardant cross linked polyethylene (TR-XLPE) cable. XLPE and TR-XLPE underground cable can be installed in ducts it can also be directly buried.

22.1 Degradation Mechanism

For XLPE cables, the 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.

22.2 System Hierarchy

Underground Secondary Cables asset category belongs to the Underground Systems assets grouping.

22.3 Useful Life and Typical Life

The overall useful life range of the cable itself is dependent on the cable type (*these are based on the values for secondary XLPE cables that use insulation materials i.e. TR-XLPE*):

- Direct Buried
- In Duct

22.3.1 *Direct Buried*

The useful life range of direct buried XLPE cable is 20 to 35 years; the typical life is 30 years.

22.3.2 *In Duct*

The useful life range of in duct XLPE cable is 40 to 60 years; the typical life is 40 years.

22.4 Time Based Maintenance Intervals

Underground Secondary Cables are not subject to planned maintenance.

22.5 Utilization Factors

Secondary cables are impacted by electrical loading utilization factors.

22.6 Functional Requirements

Secondary cables asset category is not subject to obsolescence.

23 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.

23.1 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.

23.2 System Hierarchy

Network Vaults asset category belongs to the Underground Systems asset grouping.

23.3 Useful Life and Typical Life

This asset can be componentized as:

- Overall
- Roof

23.3.1 *Overall*

The overall useful life range of network vaults is 40 to 80 years; the typical life is 60 years.

23.3.2 *Roof*

The roof has a useful life range of 20 to 40 years, with a typical life of 25 years.

23.4 Time Based Maintenance Intervals

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

23.5 Utilization Factors

The Network Vault asset category is not subject to the Utilization Factors discussed in this report.

23.6 Functional Requirements

Network vault asset category is not subject to obsolescence.

24 Submersible Vault

As with other types of underground vaults, submersible vaults allow for the underground installation of equipment.

24.1 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.

24.2 System Hierarchy

Submersible Vaults asset category belongs to the Underground Systems asset grouping.

24.3 Useful Life and Typical Life

This asset can be componentized as:

- Overall
- Roof

24.3.1 *Overall*

The useful life range of this asset class is 40 to 80 years; the average life is 60 years

24.3.2 *Roof*

The roof has a useful life range of 20 to 40 years, with a typical life of 25 years.

24.4 Time Based Maintenance Intervals

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

24.5 Utilization Factors

The Submersible Vault asset category is not subject to the Utilization Factors discussed in this report.

24.6 Functional Requirements

Submersible vault asset category is not subject to obsolescence.

25 Pad-Mounted Switchgear

Pad-mounted switchgear is used for protection and switching in the underground distribution system. The switching assemblies can be classified into air insulated, solid dielectric and gas insulated.

25.1 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 CO2 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.

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.

25.2 System Hierarchy

Pad-Mounted Switchgear asset category belongs to the Underground Systems assets grouping.

25.3 Useful Life and Typical Life

The overall useful life range of the switchgear itself is dependent on the pad mount switchgear type:

- Air Insulated
- Gas Insulated
- Solid Dielectric

25.3.1 *Air Insulated*

The useful life range of this air insulated pad-mounted switchgear is 20 to 40 years; the typical life is 20 years.

25.3.2 *Gas Insulated*

The useful life range of this gas insulated pad-mounted switchgear is 30 to 50 years; the typical life is 30 years.

25.3.3 *Solid Dielectric*

The useful life range of this solid dielectric pad-mounted switchgear is 30 to 50 years; the typical life is 30 years.

25.4 Time Based Maintenance Intervals

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

25.5 Utilization Factors

Pad-mounted switchgear is impacted by operating practices and electrical loading utilization factors.

25.6 Functional Requirements

Pad-mounted switchgear asset category is not subject to obsolescence.

26 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.

26.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, cable 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.

26.2 System Hierarchy

Cable Chambers asset category belongs to the Underground Systems assets grouping.

26.3 Useful Life and Typical Life

This asset can be componentized as:

- Overall
- Roof

26.3.1 *Overall*

Cable chambers have a useful life range of 50 to 80 years; the typical life range is 60 years.

26.3.2 *Roof*

The roof has a useful life range of 20 to 40 years, with a typical life of 25 years.

26.4 Time Based Maintenance Intervals

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

26.5 Utilization Factors

The Cable Chamber asset category is not subject to the Utilization Factors discussed in this report.

26.6 Functional Requirements

Cable chamber asset category is not subject to obsolescence.

27 Transformer and Switchgear Foundations

This asset is a buried pre cast concrete vault on which pad-mounted transformers or switchgear are mounted. The foundation itself is buried; however the top portion is above ground.

27.1 Degradation Mechanism

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, transformer and switchgear foundation must withstand heavy loads associated with traffic in the boulevard. When located in driving lanes, concrete vault must match street grading. Since vaults often experience flooding, they sometimes include drainage sumps and sump pumps. Nevertheless, environmental regulations in some jurisdictions may prohibit the pumping 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. Transformer and switchgear foundation 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. Transformer and switchgear foundation 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 transformer and switchgear foundation. Similarly, transformer and switchgear foundation with lights that do not function properly constitute defective systems.

27.2 System Hierarchy

Transformer and Switchgear Foundations asset category belongs to the Underground Systems assets grouping.

27.3 Useful Life and Typical Life

The overall useful life range of Transformer and switchgear foundation is 30 to 80 years; the typical life is 60 years.

27.4 Time Based Maintenance Intervals

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

27.5 Utilization Factors

The Transformer and Switchgear Foundations asset category is not subject to the Utilization Factors discussed in this report.

27.6 Functional Requirements

Transformer & switchgear foundations asset category is not subject to obsolescence.

28 Duct Bank

In areas such as road crossings, ducts 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 two to six inches in diameter.

28.1 Degradation Mechanism

The ducts connecting one utility chamber to another cannot easily be assessed for condition without excavating areas suspected of suffering failures. However, water ingress to a utility 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.

28.2 System Hierarchy

Duct Banks asset category belongs to the Underground Systems assets grouping.

28.3 Useful Life and Typical Life

The useful life range of the duct bank type is 30 to 80 years; the typical life is 50 years.

28.4 Time Based Maintenance Intervals

Duct banks are not subject to planned maintenance.

28.5 Utilization Factors

The Duct Bank asset category is not subject to the Utilization Factors discussed in this report.

28.6 Functional Requirements

Duct bank asset category is not subject to obsolescence.

29 Meters

The metering is how electricity providers measure billable services by measuring various aspects of power usage. When used in electricity retailing, the utilities record the values measured by these meters to generate an invoice for the electricity. This report focuses on those meters used for residential meters, industrial/commercial meters and wholesale meters. This asset consists of three components: the meter itself, the current transformer (CT) and the potential transformer (PT).

29.1 Degradation Mechanism

The major degradation mechanism of traditional meters is listed as follows:

- Electronic component aging due to long-term power quality impact, for solid-state meters
- Meter creep due to high temperature for induction type meters. This occurs when the meter disc rotates continuously with potential applied and the load terminals open circuited
- Magnetization alteration due to overload or short-circuited conditions
- Mechanical damage due to vibration of meter mounting
- Other adverse operating environment that might expedite the aging of components, such as humidity or dirt

29.2 System Hierarchy

Metering asset category belongs to the Monitoring and Control Systems assets grouping.

29.3 Useful Life and Typical Life

The overall useful life range of the meter itself is dependent on the meter type and component, which can be broken down into the following:

- Primary (Overhead, Pad-mounted)
- Residential
- Industrial/Wholesale (Electromechanical, Interval)
- Transformer (CT,PT)

29.3.1 *Primary*

The useful life range of the overhead primary meter components is 20 to 50 years; typical life is 30 years.

The useful life range of the pad-mounted primary meter components is 20 to 50 years; typical life is 30 years.

29.3.2 *Residential*

The useful life range of residential type meter is 20 to 45 years; typical life is 30 years.

29.3.3 *Industrial/ Wholesale*

The useful life range of electromechanical industrial/wholesale type meter is 20 to 60 years; typical life is 30 years.

The useful life range of interval industrial/wholesale type meter is 10 to 15 years; typical life is 15 years.

29.3.4 *Transformer*

The useful life range of the current transformer components is 30 to 50 years; typical life is 45 years.

The useful life range of the potential transformer components is 30 to 50 years; typical life is 45 years.

29.4 Time Based Maintenance Intervals

Meters are not subject to planned maintenance.

29.5 Utilization Factors

The Meters asset category is not subject to the Utilization Factors discussed in this report.

29.6 Functional Requirements

Meters are subject to obsolescence.

30 Smart Meters

A smart meter is an advanced meter is an electrical meter that identifies consumption in more detail than a conventional meter; and communicates that information via some network back to the local utility for monitoring and billing purposes.

30.1 Degradation Mechanism

The major degradation mechanism of smart metering system is listed as follows:

- Wiring insulation deterioration due to corrosion, moisture or overheating
- Poor electrical connections due to corrosion, vibration or other physical problems
- Cabinetry or rack damage or wear
- Faulty electronic components

The rate and severity of degradation in the equipment depend on its operational duties and environmental factors. Corrosion and moisture ingress, or combinations of these, represent the most critical degradation processes in microwave equipment of smart metering system.

Environmental conditions in relay and switch-rooms can affect microwave equipment's condition and reliability. Humidity, temperature, dust and pollution can cause component degradation. When plant temperatures fall below the dew point condensation can occur. When water enters equipment rooms through roof or other leaks, it can affect performance and aggravate corrosion.

30.2 System Hierarchy

Smart Metering asset category belongs to the Monitoring and Control Systems assets grouping.

30.3 Useful Life and Typical Life

There are several components of the smart meter which have their own useful and typical life:

- Smart Meter
- Computer (Hardware, Software)
- Data Concentrator (Collector)
- Repeater
- Communication Tower

30.3.1 *Smart Meter*

The useful life range of the smart meter is 15 to 20 years; typical life is 15 years.

30.3.2 *Computer*

Please see Section 32.3.3 Electrical*, for Computer component information.*

30.3.3 *Data Concentrator (Collector)*

The useful life range of the data concentrator (collector) is 10 to 20 years; typical life is 20 years.

30.3.4 *Repeater*

The useful life range of the repeater is 5 to 15 years; typical life is 10 years.

30.3.5 *Communication Tower*

The useful life range of the repeater is 35 to 100 years; typical life is 63 years.

30.4 Time Based Maintenance Intervals

Smart Meters are not subject to planned maintenance.

30.5 Utilization Factors

The Smart Meters asset category is not subject to the Utilization Factors discussed in this report.

30.6 Functional Requirements

Smart meters are subject to obsolescence.

31 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.

31.1 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.

31.2 System Hierarchy

SCADA RTUs asset category belongs to the Monitoring and Control Systems assets grouping.

31.3 Useful Life and Typical Life

The useful life of SCADA RTUs is in the range of 15 to 30 years; the typical life is 20 years.

31.4 Time Based Maintenance Intervals

SCADA RTUs are not subject to planned maintenance.

31.5 Utilization Factors

SCADA RTU is impacted by the operating practices utilization factor.

31.6 Functional Requirements

SCADA RTU is subject to obsolescence.

32 Administrative Buildings

Buildings at major transformer and municipal stations house the switchgear, relays and controls and serve as a base for administrative and service work. This asset includes the mechanical, civil, electrical and parking components. The electrical component includes control systems, security systems and computer networks.

32.1 Degradation Mechanism

The following contribute to the degradation of this asset:

- Moisture
- Heat
- Settlement
- Chemicals
- Biological

Moisture is by far the most common cause for deterioration. Almost all deterioration processes involve the physical transport of deleterious agents into the building materials and chemical or biological reactions that break down the integrity of the material. Moisture is required for almost all such actions. Hence, keeping building materials in a dry state will greatly reduce the rate of deterioration. In fact, conditions under which wetting and drying take place are the worst for the durability of building materials. If materials are always under water (e.g. in some foundations), deterioration can be very slow, because they will be starved of oxygen, which is another ingredient required for degradation, whether the corrosion of steel or the biological (insect and fungal) attack on timber. Masonry is the material that is probably least affected by moisture, although continued exposure to moisture could soften it. Masonry of course traps a lot of moisture (i.e. it dried out very slowly) and this can affect timber, steel or reinforced concrete elements that are connected to masonry walls. Buildings can experience moisture from external sources (e.g. rainwater) as well as internal sources (e.g. toilet areas, leaks from pipes and condensation in air conditioning systems). Moisture in buildings can also impair electrical systems, thus compromising serviceability.

Heat will accelerate all deterioration processes. In addition, heat can cause expansion (and subsequent contraction when the heat source is absent). Such thermal movements can weaken materials with low tensile strengths such as masonry, and cause cracking. Heat (especially in combination with direct solar radiation) can also weaken some waterproofing materials, and cause them to lose their flexibility or even to crack.

The settlement of building will also affect mainly masonry walls. In addition, if pipes are damaged during settlement, leakage of water will ensue, with the consequent potential for deterioration.

Common chemical agents can affect the degradation of buildings. Atmospheric carbon dioxide reduces the alkalinity of concrete and will lead to depassivation of steel reinforcement. Chlorides (the main source of which is from sea spray near the coastline) will also lead to such reduction in alkalinity, and also promote electrolytic corrosion processes in both reinforced concrete and steel. Sulphates (which are found in some groundwater) can attack the concrete itself, causing cracking and weakening in foundations. Sulphates and chlorides can also get into concrete through impure mixing water.

Deterioration of timber is mainly a biological process. In particular, termite attack can be very damaging. If mosses are allowed to grow on damp building elements, they will trap further moisture, thus accelerating the deterioration processes associated with moisture (see above). Apart from this, if plants are allowed to take root in buildings, they can cause severe cracks, not only in masonry, but also in concrete.

32.2 System Hierarchy

Administrative building asset category does not to an assets grouping.

32.3 Useful Life and Typical Life

This asset has three major components, each of which has a different useful life. From a maintenance practice perspective, the building can be componentized into the following:

- Building (Mechanical, Civil, Electrical, Parking)
- Roof
- Fence

32.3.1 *Building*

The useful life of the <u>mechanical</u> components of the building can be in the range of 12 to 30 years, with a typical life of 20 years.

The useful life of the <u>civil</u> components of the building can be in the range of 30 to 100 years, with a typical life of 50-60 years.

The useful life of the <u>electrical</u> components of the building can be in the range of 12 to 40 years, with a typical life of 20 years.

The useful life of the <u>parking</u> components of the building can be in the range of 15 to 30 years, with a typical life of 20 years.

32.3.2 *Roof*

The useful life of the roof can be in the range of 15 to 30 years, with a typical life of 20 years.

32.3.3 *Fence*

The useful life range of the fence is 30 to 60 years, with a typical life of 35 years.

32.4 Time Based Maintenance Intervals

The typical routine inspection interval for this asset is every year.

32.5 Utilization Factors

The Buildings asset category is not subject to the Utilization Factors discussed in this report.

32.6 Functional Requirements

Administrative buildings asset category is not subject to obsolescence.

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APPENDIX 4E – OEB PILs WORK FORM FOR 2013

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Income Tax/PILs Workform for 2013 Filers

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income							$ 3,338,278	**A**
Ontario Income Taxes								
Income tax payable	**Ontario Income Tax**	11.50%	**B**	$	383,902	**C = A * B**		
Small business credit	Ontario Small Business Threshold	$ 500,000	**D**					
	Rate reduction	-7.00%	**E**	-$	35,000	**F = D * E**		
Ontario Income tax							$ 348,902	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate				10.45%	**K = J / A**		
	Federal tax rate				15.00%	**L**		
	Combined tax rate						25.45%	**M = K + L**
Total Income Taxes							**$ 849,644**	**N = A * M**
Investment Tax Credits							$ 105,000	**O**
Miscellaneous Tax Credits							$ 48,000	**P**
Total Tax Credits							**$ 153,000**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 696,644**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up [1]					74.55%	**S = 1 - M**	**$ 237,841**	**T = R / S - R**
Income Tax (grossed-up)							**$ 934,484**	**U = R + T**

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Income Tax/PILs Workform for 2013 Filers

Taxable Income - Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		9,834,653
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	16,633,200
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	37,200
Non-deductible automobile expenses	122	
Non-deductible life insurance premiums	123	
Non-deductible company pension plans	124	525,000
Tax reserves beginning of year	125	0
Reserves from financial statements- balance at end of year	126	0
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	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
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	105,000
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	
Apprenticeship and Co-op tax credits	294	48,000
	295	
	296	
	297	
ARO Accretion expense		
Capital Contributions Received (ITA 12(1)(x))		
Lease Inducements Received (ITA 12(1)(x))		
Deferred Revenue (ITA 12(1)(a))		
Prior Year Investment Tax Credits received		
Total Additions		**17,348,400**
Deductions:		
Gain on disposal of assets per financial statements	401	64,000
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	23,593,010
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10 CEC	405	37,765
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	0
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	

Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
ARO Payments - Deductible for Tax when Paid		
ITA 13(7.4) Election - Capital Contributions Received		
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds		
Deferred Revenue - ITA 20(1)(m) reserve		
Principal portion of lease payments		
Lease Inducement Book Amortization credit to income		
Financing fees for tax ITA 20(1)(e) and (e.1)		
Sale of scrap proceeds		150,000
Total Deductions		**23,844,775**
NET INCOME FOR TAX PURPOSES		**3,338,278**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**3,338,278**

Income Tax/PILs
Workform for 2013 Filers

Schedule 8 CCA - Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}
1	Distribution System - post 1987	$ 79,203,173			$ 79,203,173	$ -
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ 776,000	575,000		$ 1,351,000	$ 287,500
2	Distribution System - pre 1988	$ 33,909,697			$ 33,909,697	$ -
8	General Office/Stores Equip	$ 18,077,462	976,200		$ 19,053,662	$ 488,100
10	Computer Hardware/ Vehicles	$ 3,519,075	1,210,000		$ 4,729,075	$ 605,000
10.1	Certain Automobiles	$ -			$ -	$ -
12	Computer Software	$ 2,660,000	5,520,000		$ 8,180,000	$ 2,760,000
13 1	Lease # 1	$ -			$ -	$ -
13 2	Lease #2	$ -			$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -
14	Franchise	$ -			$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than B	$ -			$ -	$ -
42	Fibre Optic Cable	$ -			$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ -			$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -			$ -	$ -
47	Distribution System - post February 2005	$ 80,085,873	17,060,200	-280,000	$ 96,866,073	$ 8,390,100
50	Data Network Infrastructure Equipment - post Mar 2007	$ 470,510	480,000		$ 950,510	$ 240,000
52	Computer Hardware and system software	$ -			$ -	$ -
95	CWIP	$ -			$ -	$ -
38	Power-operated movable equipment	$ 420,089	200,000		$ 620,089	$ 100,000
1	Buildings pre 2007	$ 8,281,781			$ 8,281,781	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
					$ -	$ -
	TOTAL	$ 227,403,659	$ 26,021,400	-$ 280,000	$ 253,145,059	$ 12,870,700

Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
$ 79,203,173	4%	$ 3,168,127	$ 76,035,046
$ 1,063,500	6%	$ 63,810	$ 1,287,190
$ 33,909,697	6%	$ 2,034,582	$ 31,875,115
$ 18,565,562	20%	$ 3,713,112	$ 15,340,549
$ 4,124,075	30%	$ 1,237,222	$ 3,491,852
$ -	30%	$ -	$ -
$ 5,420,000	100%	$ 5,420,000	$ 2,760,000
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -		$ -	$ -
$ -	8%	$ -	$ -
$ -	12%	$ -	$ -
$ -	30%	$ -	$ -
$ -	50%	$ -	$ -
$ -	45%	$ -	$ -
$ -	30%	$ -	$ -
$ 88,475,973	8%	$ 7,078,078	$ 89,787,995
$ 710,510	55%	$ 390,780	$ 559,729
$ -	100%	$ -	$ -
$ -	0%	$ -	$ -
$ 520,089	30%	$ 156,027	$ 464,063
$ 8,281,781	4%	$ 331,271	$ 7,950,510
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ -	0%	$ -	$ -
$ 240,274,359		**$ 23,593,010**	**$ 229,552,050**

Income Tax/PILs Workforms for 2013 Filers

Schedule 10 CEC - Test Year

Cumulative Eligible Capital				539,504
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
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	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				539,504
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**
Cumulative Eligible Capital Balance				**539,504**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**539,504**	**x 7% =**	**37,765**
Cumulative Eligible Capital - Closing Balance				**501,738**

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APPENDIX 4F – CCA SCHEDULES 2009 TO 2013

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LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2013 TEST YEAR FORECAST - MIFRS

CCA CONTINUITY SCHEDULE (2013 TEST) - MIFRS

Class	Class description	UCC prior year ending balance	Additions	Dispositions	UCC before 1/2 year adjustment	1/2 year rule (1/2 additions, less disposals)	Reduced UCC	Rate %	CCA	UCC ending balance
1	Distribution system - 1988 to Feb 22, 2005	79,203,173			79,203,173	-	79,203,173	4%	3,168,127	76,035,046
1	Buildings - pre 2007	8,281,781			8,281,781	-	8,281,781	4%	331,271	7,950,510
1	Buildings - post 2007	776,000	575,000		1,351,000	(287,500)	1,063,500	6%	63,810	1,287,190
2	Distribution system - pre 1988	33,909,697	-		33,909,697	-	33,909,697	6%	2,034,582	31,875,115
8	Equipment	18,077,461	976,200		19,053,661	(488,100)	18,565,561	20%	3,713,112	15,340,549
10	Computer hardware / vehicles	3,519,075	1,210,000		4,729,075	(605,000)	4,124,075	30%	1,237,222	3,491,853
12	Computer software	2,660,000	5,520,000		8,180,000	(2,760,000)	5,420,000	100%	5,420,000	2,760,000
38	Power-operated equipment	420,089	200,000		620,089	(100,000)	520,089	30%	156,027	464,062
47	Distribution system - post Feb 22, 2005	80,085,873	17,060,200	(280,000)	96,866,073	(8,390,100)	88,475,973	8%	7,078,078	89,787,995
50	Computer hardware - post 2007	470,510	480,000		950,510	(240,000)	710,510	55%	390,781	559,729
		227,403,659	**26,021,400**	**(280,000)**	**253,145,059**	**(12,870,700)**	**240,274,359**		**23,593,010**	**229,552,049**

LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2012 BRIDGE YEAR FORECAST - MIFRS

CCA CONTINUITY SCHEDULE (2012 BRIDGE) - MIFRS										
Class	**Class description**	**UCC prior year ending balance**	**Additions**	**Dispositions**	**UCC before 1/2 year adjustment**	**1/2 year rule (1/2 additions, less disposals)**	**Reduced UCC**	**Rate %**	**CCA**	**UCC ending balance**
1	Distribution system - 1988 to Feb 22, 2005	82,503,305			82,503,305	-	82,503,305	4%	3,300,132	79,203,173
1	Buildings - pre 2007	8,626,855			8,626,855	-	8,626,855	4%	345,074	8,281,781
1	Buildings - post 2007	-	800,000		800,000	(400,000)	400,000	6%	24,000	776,000
2	Distribution system - pre 1988	36,074,146	-		36,074,146	-	36,074,146	6%	2,164,449	33,909,697
8	Equipment	20,903,701	1,505,000		22,408,701	(752,500)	21,656,201	20%	4,331,240	18,077,461
10	Computer hardware / vehicles	2,896,178	1,755,000		4,651,178	(877,500)	3,773,678	30%	1,132,103	3,519,075
12	Computer software	2,374,025	5,320,000		7,694,025	(2,660,000)	5,034,025	100%	5,034,025	2,660,000
38	Power-operated equipment	436,199	135,000		571,199	(67,500)	503,699	30%	151,110	420,089
47	Distribution system - post Feb 22, 2005	70,024,158	16,596,300	(280,000)	86,340,458	(8,158,150)	78,182,308	8%	6,254,585	80,085,873
50	Computer hardware - post 2007	323,799	448,000		771,799	(224,000)	547,799	55%	301,289	470,510
		224,162,366	**26,559,300**	**(280,000)**	**250,441,666**	**(13,139,650)**	**237,302,016**		**23,038,007**	**227,403,659**

LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2013 TEST YEAR - CGAAP

CCA CONTINUITY SCHEDULE (2013 TEST) - CGAAP

Class	Class description	UCC prior year ending balance	Additions	Dispositions	UCC before 1/2 year adjustment	1/2 year rule (1/2 additions, less disposals)	Reduced UCC	Rate %	CCA	UCC ending balance
1	Distribution system - 1988 to Feb 22, 2005	79,203,173			79,203,173	-	79,203,173	4%	3,168,127	76,035,046
1	Buildings - pre 2007	8,281,781			8,281,781	-	8,281,781	4%	331,271	7,950,510
1	Buildings - post 2007	776,000	575,000		1,351,000	(287,500)	1,063,500	6%	63,810	1,287,190
2	Distribution system - pre 1988	33,909,697	-		33,909,697	-	33,909,697	6%	2,034,582	31,875,115
8	Equipment	18,080,521	979,600		19,060,121	(489,800)	18,570,321	20%	3,714,064	15,346,057
10	Computer hardware / vehicles	3,519,075	1,210,000		4,729,075	(605,000)	4,124,075	30%	1,237,222	3,491,853
12	Computer software	2,660,000	5,520,000		8,180,000	(2,760,000)	5,420,000	100%	5,420,000	2,760,000
38	Power-operated equipment	420,089	200,000		620,089	(100,000)	520,089	30%	156,027	464,062
47	Distribution system - post Feb 22, 2005	80,739,921	17,793,400	(280,000)	98,253,321	(8,756,700)	89,496,621	8%	7,159,730	91,093,591
50	Computer hardware - post 2007	470,510	480,000		950,510	(240,000)	710,510	55%	390,781	559,729
		228,060,767	**26,758,000**	**(280,000)**	**254,538,767**	**(13,239,000)**	**241,299,767**		**23,675,614**	**230,863,153**

LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2012 BRIDGE YEAR - CGAAP

CCA CONTINUITY SCHEDULE (2012 BRIDGE) - CGAAP

Class	Class description	UCC prior year ending balance	Additions	Dispositions	UCC before 1/2 year adjustment	1/2 year rule (1/2 additions, less disposals)	Reduced UCC	Rate %	CCA	UCC ending balance
1	Distribution system - 1988 to Feb 22, 2005	82,503,305			82,503,305	-	82,503,305	4%	3,300,132	79,203,173
1	Buildings - pre 2007	8,626,855			8,626,855	-	8,626,855	4%	345,074	8,281,781
1	Buildings - post 2007	-	800,000		800,000	(400,000)	400,000	6%	24,000	776,000
2	Distribution system - pre 1988	36,074,146			36,074,146	-	36,074,146	6%	2,164,449	33,909,697
8	Equipment	20,903,701	1,508,400		22,412,101	(754,200)	21,657,901	20%	4,331,580	18,080,521
10	Computer hardware / vehicles	2,896,178	1,755,000		4,651,178	(877,500)	3,773,678	30%	1,132,103	3,519,075
12	Computer software	2,374,025	5,320,000		7,694,025	(2,660,000)	5,034,025	100%	5,034,025	2,660,000
38	Power-operated equipment	436,199	135,000		571,199	(67,500)	503,699	30%	151,110	420,089
47	Distribution system - post Feb 22, 2005	70,024,158	17,277,600	(280,000)	87,021,758	(8,498,800)	78,522,958	8%	6,281,837	80,739,921
50	Computer hardware - post 2007	323,799	448,000		771,799	(224,000)	547,799	55%	301,289	470,510
		224,162,366	**27,244,000**	**(280,000)**	**251,126,366**	**(13,482,000)**	**237,644,366**		**23,065,599**	**228,060,767**

LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2011 ACTUAL

CCA CONTINUITY SCHEDULE (2011) - ACTUAL										
Class	Class description	UCC prior year ending balance	Additions	Dispositions	UCC before 1/2 year adjustment	1/2 year rule (1/2 additions, less disposals)	Reduced UCC	Rate %	CCA	UCC ending balance
1	Distribution system - 1988 to Feb 22, 2005	85,940,943			85,940,943	-	85,940,943	4%	3,437,638	82,503,305
1	Buildings	8,347,621	625,653		8,973,273	(312,826)	8,660,447	4%	346,418	8,626,855
2	Distribution system - pre 1988	38,376,751	-		38,376,751	-	38,376,751	6%	2,302,605	36,074,146
8	Equipment	3,924,457	4,444,846		8,369,304	(2,222,423)	6,146,880	20%	1,229,376	7,139,928
10	Computer hardware / vehicles	3,866,258	223,290		4,089,549	(111,645)	3,977,904	30%	1,193,371	2,896,178
12	Computer software	1,491,658	2,481,132		3,972,790	(1,240,566)	2,732,224	100%	2,732,224	1,240,566
38	Power-operated equipment	403,219	181,113		584,332	(90,557)	493,775	30%	148,133	436,199
47	Distribution system - post Feb 22, 2005	59,439,390	16,451,194	(472,112)	75,418,472	(7,989,541)	67,428,931	8%	5,394,314	70,024,158
50	Computer hardware - post 2007	62,854	406,298		469,152	(203,149)	266,003	55%	146,302	322,850
Rate Base CCA		**201,853,151**	**24,813,527**	**(472,112)**	**226,194,566**	**(12,170,707)**	**214,023,858**		**16,930,381**	**209,264,185**
8	Equipment	16,580,599	554,772		17,135,371	(277,386)	16,857,985	20%	3,371,597	13,763,774
12	Computer software	1,829,297	2,266,918		4,096,215	(1,133,459)	2,962,756	100%	2,962,756	1,133,459
50	Computer hardware - post 2007		1,309		1,309	(655)	655	55%	360	949
Smart meter deferral CCA		**18,409,896**	**2,822,998**	**-**	**21,232,894**	**(1,411,499)**	**19,821,395**		**6,334,713**	**14,898,181**
43.2	Renewable generation equipment		935,237		935,237	(467,619)	467,619	50%	233,809	701,428
Non-distribution CCA		**-**	**935,237**	**-**	**935,237**	**(467,619)**	**467,619**		**233,809**	**701,428**
		220,263,047	**28,571,762**	**(472,112)**	**248,362,697**	**(14,049,825)**	**234,312,872**		**23,498,903**	**224,863,794**

LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2010 ACTUAL

CCA CONTINUITY SCHEDULE (2010) - ACTUAL										
Class	**Class description**	**UCC prior year ending balance**	**Additions**	**Dispositions**	**UCC before 1/2 year adjustment**	**1/2 year rule (1/2 additions, less disposals)**	**Reduced UCC**	**Rate %**	**CCA**	**UCC ending balance**
1	Distribution system - 1988 to Feb 22, 2005	89,521,816			89,521,816	-	89,521,816	4%	3,580,873	85,940,943
1	Buildings	8,104,562	578,818		8,683,380	(289,409)	8,393,971	4%	335,759	8,347,621
2	Distribution system - pre 1988	40,826,331			40,826,331	-	40,826,331	6%	2,449,580	38,376,751
8	Equipment	4,579,553	856,096	(637,089)	4,798,560	(428,047)	4,370,513	20%	874,103	3,924,457
10	Computer hardware / vehicles	2,791,197	2,249,906		5,041,103	(1,124,953)	3,916,150	30%	1,174,845	3,866,258
12	Computer software	4,017,676	2,983,317		7,000,992	(1,491,658)	5,509,334	100%	5,509,334	1,491,658
38	Power-operated equipment	127,519	369,359		496,878	(184,680)	312,198	30%	93,659	403,219
47	Distribution system - post Feb 22, 2005	52,941,232	11,920,201	(739,517)	64,121,916	(5,590,342)	58,531,574	8%	4,682,526	59,439,390
50	Computer hardware - post March 18, 2007	139,675	-		139,675	-	139,675	55%	76,821	62,854
52	Computer hardware - Jan 27, 2009 to Jan 2011	(0)	283,350		283,350	-	283,350	100%	283,350	0
Rate Base CCA		**203,049,560**	**19,241,047**	**(1,376,606)**	**220,914,001**	**(9,109,089)**	**211,804,912**		**19,060,850**	**201,853,151**
8	Equipment	4,787,122	14,167,668		18,954,790	(7,083,834)	11,870,956	20%	2,374,191	16,580,599
12	Computer software		1,829,297		1,829,297	(914,649)	914,649	100%	-	1,829,297
52	Computer hardware - Jan 27, 2009 to Jan 2011		264,510		264,510	-	264,510	100%	264,510	-
Smart meter deferral CCA		**4,787,122**	**16,261,475**	**-**	**21,048,597**	**(7,998,483)**	**13,050,115**		**2,638,701**	**18,409,896**
		207,836,682	**35,502,522**	**(1,376,606)**	**241,962,598**	**(17,107,572)**	**224,855,026**		**21,699,551**	**220,263,047**

LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2009 ACTUAL

CCA CONTINUITY SCHEDULE (2009) - ACTUAL										
Class	Class description	UCC prior year ending balance	Additions	Dispositions	UCC before 1/2 year adjustment	1/2 year rule (1/2 additions, less disposals)	Reduced UCC	Rate %	CCA	UCC ending balance
1	Distribution system - 1988 to Feb 22, 2005	93,251,892			93,251,892	-	93,251,892	4%	3,730,076	89,521,816
1	Buildings	7,839,749	590,207		8,429,956	(295,104)	8,134,852	4%	325,394	8,104,562
2	Distribution system - pre 1988	43,432,267			43,432,267	-	43,432,267	6%	2,605,936	40,826,331
8	Equipment	5,405,592	283,777	(355)	5,689,014	(141,711)	5,547,303	20%	1,109,461	4,579,553
10	Computer hardware / vehicles	2,566,287	1,207,667	(37,318)	3,736,635	(585,174)	3,151,461	30%	945,438	2,791,197
12	Computer software	224,565	8,035,352		8,259,917	(4,017,676)	4,242,241	100%	4,242,241	4,017,676
38	Power-operated equipment	84,185	81,340	(648)	164,878	(40,346)	124,532	30%	37,359	127,519
47	Distribution system - post Feb 22, 2005	42,595,458	14,647,757	(321,288)	56,921,927	(7,163,235)	49,758,692	8%	3,980,695	52,941,232
50	Computer hardware - post March 18, 2007	310,389	-		310,389	-	310,389	55%	170,714	139,675
52	Computer hardware - Jan 27, 2009 to Jan 2011		345,288		345,288	-	345,288	100%	345,288	(0)
Rate Base CCA		**195,710,384**	**25,191,387**	**(359,609)**	**220,542,162**	**(12,243,245)**	**208,298,917**		**17,492,602**	**203,049,560**
8	Equipment		5,319,024		5,319,024	(2,659,512)	2,659,512	20%	531,902	4,787,122
Smart meter deferral CCA		**-**	**5,319,024**	**-**	**5,319,024**	**(2,659,512)**	**2,659,512**		**531,902**	**4,787,122**
		195,710,384	**30,510,411**	**(359,609)**	**225,861,186**	**(14,902,757)**	**210,958,429**		**18,024,504**	**207,836,682**

LONDON HYDRO INC.

CAPITAL COST ALLOWANCE

2009 BOARD APPROVED

CCA CONTINUITY SCHEDULE (2009) - BOARD APPROVED										
Class	Class description	UCC prior year ending balance	Additions	Dispositions	UCC before 1/2 year adjustment	1/2 year rule (1/2 additions, less disposals)	Reduced UCC	Rate %	CCA	UCC ending balance
1	Distribution system - 1988 to Feb 22, 2005	93,251,892			93,251,892	-	93,251,892	4%	3,730,076	89,521,816
1	Buildings	5,611,952			5,611,952	-	5,611,952	4%	224,478	5,387,474
2	Distribution system - pre 1988	43,432,267			43,432,267	-	43,432,267	6%	2,605,936	40,826,331
8	Equipment	3,640,819	1,024,500		4,665,319	(512,250)	4,153,069	20%	830,614	3,834,705
10	Computer hardware / vehicles	2,944,492	1,728,000		4,672,492	(864,000)	3,808,492	30%	1,142,548	3,529,944
12	Computer software	230,039	9,279,905		9,509,944	(4,639,953)	4,869,992	100%	4,869,992	4,639,952
38	Power-operated equipment				-	-	-	30%	-	-
47	Distribution system - post Feb 22, 2005	44,421,028	18,492,100		62,913,128	(9,246,050)	53,667,078	8%	4,293,366	58,619,762
50	Computer hardware - post March 18, 2007	238,586			238,586	-	238,586	55%	131,222	107,364
52	Computer hardware - Jan 28, 2009 to Jan 31, 2011		47,500		47,500	-	47,500	100%	47,500	-
		193,771,075	**30,572,005**	**-**	**224,343,080**	**(15,262,253)**	**209,080,828**		**17,875,732**	**206,467,348**

APPENDIX 4G – PILs 2011 CORPORATE TAX RETURN

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Canada Revenue Agency | Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

- You have to complete this return to allow your transmitter to electronically file your corporation income tax return to us at the Canada Revenue Agency. You have to complete this return for each tax year.
- By completing part B and signing part C, you acknowledge that, under the *Income Tax Act*, you have to keep all records used to prepare your corporation income tax return, and provide this information to us on request.
- Part D must be completed by either you or the electronic transmitter of your corporation income tax return.
- Give the signed original of this return to the transmitter and keep a copy for yourself. Under the Act, you have to keep your copy for six years.
- We are responsible for ensuring the confidentiality of your electronically filed tax information only after we have accepted it.

This return is for your records. Do not send it to us unless we ask for it.

Part A – Identification

Name of corporation
London Hydro Inc.

Business Number	Tax year	From Y M D	To Y M D
86483 7430 RC0001		2011-01-01	2011-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	5,469,972
Part I tax payable (line 700)	
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, Arnold (Last name in block letters), David (First name in block letters), CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

2012-06-22		(519) 661-5800
Date (yyyy/mm/dd)	Signature of an authorized signing officer of the corporation	Telephone number

Part D – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm: KPMG LLP

Electronic filer number:

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

INFORMATION RETURN FOR CORPORATIONS FILING ELECTRONICALLY

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- Give the signed original of this return to the transmitter and keep a copy for yourself. Under the Act, you have to keep your copy for six years.
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Part A – Identification

Name of corporation
London Hydro Inc.

Business Number	Tax year	From (Y M D)	To (Y M D)
86483 7430 RC0001		2011-01-01	2011-12-31

Part B – Declaration

Enter the following amounts, if applicable, from your corporation income tax return for the tax year noted above:

Net income or (loss) for income tax purposes from Schedule 1, financial statements or GIFI (line 300)	5,469,972
Part I tax payable (line 700)	
Part II surtax payable (line 708)	
Part III.1 tax payable (line 710)	
Part IV tax payable (line 712)	
Part IV.1 tax payable (line 716)	
Part VI tax payable (line 720)	
Part VI.1 tax payable (line 724)	
Part XIV tax payable (line 728)	
Net provincial and territorial tax payable (line 760)	
Provincial tax on large corporations (line 765)	

Part C – Certification and authorization

I, Arnold (Last name in block letters), David (First name in block letters), CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined the corporation T2 income tax return, including accompanying schedules and statements, and that the information given on the T2 return and this T183 Corp information return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

I authorize the transmitter identified in Part D to electronically file the corporation income tax return identified in Part A. The transmitter can also modify the information originally filed in response to any errors Canada Revenue Agency identifies. This authorization expires when the Minister of National Revenue accepts the electronic return as filed.

2012-06-22		(519) 661-5800
Date (yyyy/mm/dd)	Signature of an authorized signing officer of the corporation	Telephone number

Part D – Transmitter identification

The following transmitter has electronically filed the tax return of the corporation identified in Part A.

Name of person or firm: KPMG LLP

Electronic filer number:

Privacy Act, Personal Information Bank number CRA PPU 047

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

EXEMPT FROM TAX

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) **001** 86483 7430 RC0001

Corporation's name
002 London Hydro Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 111 Horton Street
012
City: **015** London
Province, territory, or state: **016** ON
Country (other than Canada): **017**
Postal code/Zip code: **018** N6A 4H6

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: **025**
Province, territory, or state: **026**
Country (other than Canada): **027**
Postal code/Zip code: **028**

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 111 Horton Street
032
City: **035** London
Province, territory, or state: **036** ON
Country (other than Canada): **037**
Postal code/Zip code: **038** N6A 4H6

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ________ YYYY MM DD

To which tax year does this return apply?
Tax year start **060** 2011-01-01 (YYYY MM DD)
Tax year-end **061** 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]
Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [X] Exempt under other paragraphs of section 149

Do not use this area
095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No X
Is the corporation inactive?	280	1 Yes	2 No X

What is the corporation's main revenue-generating business activity? . . . . . 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	YYYY MM DD	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	1 Yes	2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	5,469,972	A
Deduct: Charitable donations from Schedule 2	311				
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction*	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal			▶		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				5,469,972	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	5,469,972	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)					Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	5,469,972	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405		B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 ***** 495,428 D / 11,250 = 22,019,022 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = 430 ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*				A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			B	
Amount QQ from Part 13 of Schedule 27			C	
Personal service business income**	432		D	
Amount used to calculate the credit union deduction from Schedule 17			E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			F	
Aggregate investment income from line 440 on page 6***			G	
Total of amounts B to G			▶	H
Amount A **minus** amount H (if negative, enter "0")				I

Amount I		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	J
Amount I		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	K
Amount I		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	L
Amount I		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M ..... N
Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27			P	
Amount QQ from Part 13 of Schedule 27			Q	
Personal service business income*	434		R	
Amount used to calculate the credit union deduction from Schedule 17			S	
Total of amounts P to S			▶	T
Amount O **minus** amount T (if negative, enter "0")				U

Amount U		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	V
Amount U		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	W
Amount U		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	X
Amount U		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	Y

General tax reduction – Total of amounts V to Y ..... Z
Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	**440**	x 26 2 / 3 % =		A
Foreign non-business income tax credit from line 632 on page 7				
Deduct: Foreign investment income from Schedule 7	**445**	x 9 1 / 3 % =		
		(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")				C

Taxable income from line 360 on page 3			5,469,972	
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				
Foreign non-business income tax credit from line 632 on page 7	x 25 / 9 (25/9*) =			
Foreign business income tax credit from line 636 on page 7	x 1(0.38 - X**) / 3.77358 =			
		▶		
			5,469,972	
		x 26 2 / 3 % =	1,458,659	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)				E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least		**450**		F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**			
Deduct: Dividend refund for the previous tax year	**465**			
			▶	G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	**480**			
			▶	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	**485**			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	2,500,000	x 1 / 3	833,333	I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)				

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550		A
Recapture of investment tax credit from Schedule 31			602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	5,469,972		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	5,469,972 ▶	5,469,972	ii

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)			D

Deduct:

Small business deduction from line 430 on page 4			1
Federal tax abatement	608		
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount N on page 5	638		
General tax reduction from amount Z on page 5	639		
Federal logging tax credit from Schedule 21	640		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		▶	E

Part I tax payable – Line D **minus** line E .... F
Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760		
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
Total tax payable	770		A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,800,000	
Total credits	890	1,800,000	1,800,000 B

Refund code 894 1 Overpayment 1,800,000

Balance (line A **minus** line B) -1,800,000

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number

918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No ☒

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Arnold (Last name in block letters) 951 David (First name in block letters) 954 CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-06-22 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 661-5800 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 2 No ☐

958 Name in block letters — 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

990 1

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SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	66,204,000	68,531,000
	Total tangible capital assets	2008	+	386,547,000	373,648,000
	Total accumulated amortization of tangible capital assets	2009	–	180,951,000	174,378,000
	Total intangible capital assets	2178	+		
	Total accumulated amortization of intangible capital assets	2179	–		
	Total long-term assets	2589	+	28,793,000	29,206,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	300,593,000	297,007,000
	Liabilities				
	Total current liabilities	3139	+	46,154,000	49,932,000
	Total long-term liabilities	3450	+	130,384,000	128,393,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	176,538,000	178,325,000
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	124,055,000	118,682,000
	Total liabilities and shareholder equity	3640	=	300,593,000	297,007,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	27,939,000	22,566,000

***** Generic item

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SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

Income statement information

Description	GIFI	
Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
	Income statement information				
	Total sales of goods and services	8089	+	58,760,000	58,748,000
	Cost of sales	8518	–	48,360,000	46,759,000
	Gross profit/loss	8519	=	10,400,000	11,989,000
	Cost of sales	8518	+	48,360,000	46,759,000
	Total operating expenses	9367	+		
	Total expenses (mandatory field)	9368	=	48,360,000	46,759,000
`	Total revenue (mandatory field)	8299	+	57,760,000	58,161,000
	Total expenses (mandatory field)	9368	–	48,360,000	46,759,000
	Net non-farming income	9369	=	9,400,000	11,402,000
	Farming income statement information				
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	9,400,000	11,402,000
	Total other comprehensive income	9998	=		
	Extraordinary items and income (linked to Schedule 140)				
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	1,527,000	2,353,000
	Future (deferred) income tax provision	9995	–		
	Total – Other comprehensive income	9998	+		
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	7,873,000	9,049,000

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

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SCHEDULE 141

NOTES CHECKLIST

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Parts 1, 2, and 3 of this schedule must be completed from the perspective of the person (referred to in these parts as the "accountant") who prepared or reported on the financial statements.
- For more information, see Guide RC4088, *General Index of Financial Information (GIFI)* and Guide T4012, *T2 Corporation – Income Tax Guide*.
- Complete this schedule and include it with your T2 return along with the other GIFI schedules.

If the person preparing the tax return is not the accountant referred to above, they must still complete Parts 1, 2, 3, and 4, as applicable.

Part 1 – Information on the accountant who prepared or reported on the financial statements

		1 Yes	2 No
Does the accountant have a professional designation?	095	X	
Is the accountant connected* with the corporation?	097		X

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note: If the accountant does not have a professional designation **or** is connected to the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4, as applicable.

Part 2 – Type of involvement with the financial statements

Choose the option that represents the highest level of involvement of the accountant:

198		
Completed an auditor's report	1	X
Completed a review engagement report	2	
Conducted a compilation engagement	3	

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement with the financial statements** above, answer the following question:

		1 Yes	2 No
Has the accountant expressed a reservation?	099		X

Part 4 – Other information

If you have a professional designation and are not the accountant associated with the financial statements in Part 1 above, choose one of the following options:

110		
Prepared the tax return (financial statements prepared by client)	1	
Prepared the tax return and the financial information contained therein (financial statements have not been prepared)	2	

		1 Yes	2 No
Were notes to the financial statements prepared?	101	X	

If **yes**, complete lines 104 to 107 below:

		1 Yes	2 No
Are subsequent events mentioned in the notes?	104	X	
Is re-evaluation of asset information mentioned in the notes?	105		X
Is contingent liability information mentioned in the notes?	106		X
Is information regarding commitments mentioned in the notes?	107	X	
Does the corporation have investments in joint venture(s) or partnership(s)?	108		X

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . 200 1 Yes [ ] 2 No [X]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		In OCI Increase (decrease)
Property, plant, and equipment	210		211	
Intangible assets	215		216	
Investment property	220			
Biological assets	225			
Financial instruments	230		231	
Other	235		236	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year? . . . . . 250 1 Yes [ ] 2 No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . 255 1 Yes [ ] 2 No [X]

Did the corporation discontinue hedge accounting during the tax year? . . . . . 260 1 Yes [ ] 2 No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . 265 1 Yes [ ] 2 No [X]

If **yes**, you have to maintain a separate reconciliation.

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				7,873,000	A
Add:					
Provision for income taxes – current		101	1,527,000		
Interest and penalties on taxes		103	12,696		
Amortization of tangible assets		104	17,669,346		
Non-deductible meals and entertainment expenses		121	34,545		
Non-deductible company pension plans		124	776,100		
Subtotal of additions			20,019,687	20,019,687	
Other additions:					
Recapture of SR&ED expenditures – Form T661		231	94,873		
Miscellaneous other additions:					
600 Federal apprenticeship credit received re 2010		290	4,000		
603 Ontario apprentice tax credit	35,014				
Inducement - ITA 12(1)x)	6,918				
Total	41,932	293	41,932		
604 Unrealized SWAP adjustment	179,560				
Ontario Capital Tax expensed for accounting	72,948				
Income for tax purposes	1,839,120				
Total	2,091,628	294	2,091,628		
Subtotal of other additions		199	2,232,433	2,232,433	
Total additions		500	22,252,120	22,252,120	
Deduct:					
Gain on disposal of assets per financial statements		401	160,755		
Capital cost allowance from Schedule 8		403	23,498,903		
Cumulative eligible capital deduction from Schedule 10		405	43,664		
Subtotal of deductions			23,703,322	23,703,322	
Other deductions:					
Miscellaneous other deductions:					
700 Sale of scrap for accounting purposes		390	311,357		
701 Deductible expenses capitalized for accounting		391	530,328		
703 SRED refunds included in income for actg	70,141				
Total	70,141	393	70,141		
704 ATTC credits accrued for actg	40,000				
Total	40,000	394	40,000		
Subtotal of other deductions		499	951,826	951,826	
Total deductions		510	24,655,148	24,655,148	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				5,469,972	

T2 SCH 1 E (10)

Canada

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205 (Complete if payer corporation is connected)	C Business Number of connected corporation 210 (Complete if payer corporation is connected)	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220 (Complete if payer corporation is connected)	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250 (Complete if payer corporation is connected)	H Dividend refund of the connected payer corporation (for tax year in column D)** 260 (Complete if payer corporation is connected)	I Part IV tax before deductions F x 1 / 3 *** 270
					J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	The Corporation of the City of London	NR	2011-12-31	2,500,000	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 2,500,000

Total taxable dividends paid in the tax year to other than connected corporations	450	
Eligible dividends (included in line 450)	450a	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)	460	2,500,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			2,500,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	2,500,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			2,500,000

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

Ontario basic income tax (from Schedule 500) 270

Deduct: Ontario small business deduction (from schedule 500) 402

Subtotal ▶ A6

Add:

Surtax re Ontario small business deduction (from Schedule 500) 272

Ontario additional tax re Crown royalties (from Schedule 504) 274

Ontario transitional tax debits (from Schedule 506) 276

Recapture of Ontario research and development tax credit (from Schedule 508) 277

Subtotal ▶ B6

Subtotal (amount A6 **plus** amount B6) C6

Deduct:

Ontario resource tax credit (from Schedule 504) 404

Ontario tax credit for manufacturing and processing (from Schedule 502) 406

Ontario foreign tax credit (from Schedule 21) 408

Ontario credit union tax reduction (from Schedule 500) 410

Ontario transitional tax credits (from Schedule 506) 414

Ontario political contributions tax credit (from Schedule 525) 415

Subtotal ▶ D6

Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") E6

Deduct: Ontario research and development tax credit (from Schedule 508) 416

Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416)
(if negative, enter "0") F6

Deduct: Ontario corporate minimum tax credit (from schedule 510) 418

Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") G6

Add:

Ontario corporate minimum tax (from Schedule 510) 278

Ontario special additional tax on life insurance corporations (from Schedule 512) 280

Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies) 282

Subtotal ▶ H6

Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) I6

Deduct:

Ontario qualifying environmental trust tax credit 450

Ontario co-operative education tax credit (from Schedule 550) 452

Ontario apprenticeship training tax credit (from Schedule 552) 454

Ontario computer animation and special effects tax credit (from Schedule 554) 456

Ontario film and television tax credit (from Schedule 556) 458

Ontario production services tax credit (from Schedule 558) 460

Ontario interactive digital media tax credit (from Schedule 560) 462

Ontario sound recording tax credit (from Schedule 562) 464

Ontario book publishing tax credit (from Schedule 564) 466

Ontario innovation tax credit (from Schedule 566) 468

Ontario business-research institute tax credit (from Schedule 568) 470

Other Ontario tax credits . . . . .

Subtotal ▶ J6

Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) 290 K6
(if a credit, enter a negative amount) Include this amount on line 255.

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits . . . . 255 ______________

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	Buildings	8,347,620	625,653		0	312,827	8,660,446	4	0	0	346,418	8,626,855
2.	1	Distribution Equip	85,940,943			0		85,940,943	4	0	0	3,437,638	82,503,305
3.	2	Distribution Equip	38,376,751			0		38,376,751	6	0	0	2,302,605	36,074,146
4.	8	SM	16,580,599	554,772		0	277,386	16,857,985	20	0	0	3,371,597	13,763,774
5.	8	Equipment	3,924,459	4,444,846		0	2,222,423	6,146,882	20	0	0	1,229,376	7,139,929
6.	10	Vehicles/Computer b/f March 07	3,866,259	223,290		0	111,645	3,977,904	30	0	0	1,193,371	2,896,178
7.	12	SM Software	1,829,297	2,266,918		0	1,133,459	2,962,756	100	0	0	2,962,756	1,133,459
8.	12	Computer Software	1,491,659	2,481,132		0	1,240,566	2,732,225	100	0	0	2,732,225	1,240,566
9.	38	Back Hoes	403,218	181,113		0	90,557	493,774	30	0	0	148,132	436,199
10.	47		59,439,389	16,451,194		472,112	7,989,541	67,428,930	8	0	0	5,394,314	70,024,157
11.	50		62,854	406,298		0	203,149	266,003	55	0	0	146,302	322,850
12.	50	SM Computer		1,309		0	655	654	55	0	0	360	949
13.	43.2	Renewable Genration Equipment		935,237		0	467,619	467,618	50	0	0	233,809	701,428
		Totals	220,263,048	28,571,762		472,112	14,049,827	234,312,871				23,498,903	224,863,795

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (11)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	The Corporation of the City of Lond		NR	1	1,001	100.000			96,116

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0")				200	370,386 A
Add: Cost of eligible capital property acquired during the taxation year	222	337,853			
Other adjustments	226				
Subtotal (line 222 plus line 226)		337,853	x 3 / 4 = 253,390 B		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002	228		x 1 / 2 = C		
amount B minus amount C (if negative, enter "0")			253,390 ▶		253,390 D
Amount transferred on amalgamation or wind-up of subsidiary				224	E
Subtotal (add amounts A, D, and E)				230	623,776 F
Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year	242	G			
The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7)	244	H			
Other adjustments	246	I			
(add amounts G,H, and I)			x 3 / 4 =	248	J
Cumulative eligible capital balance (amount F minus amount J) (if amount K is negative, enter "0" at line M and proceed to Part 2)					623,776 K
Cumulative eligible capital for a property no longer owned after ceasing to carry on that business			249		
amount K		623,776			
less amount from line 249					
Current year deduction		623,776 x 7.00 % =	250	43,664 *	
(line 249 plus line 250) (enter this amount at line 405 of Schedule 1)				43,664 ▶	43,664 L
Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0")				300	580,112 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400	1
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401	2
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402	3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408	4		
Line 3 minus line 4 (if negative, enter "0")		▶		5
Total of lines 1, 2 and 5				6
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8		
Subtotal (line 7 plus line 8)	409	▶		9
Line 6 minus line 9 (if negative, enter "0")			▶	O
Line N minus line O (if negative, enter "0")				P
Line 5		x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")				R
Amount R		x 2 / 3 =		S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)			410	

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Asso-ciation code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	London Hydro Inc.	86483 7430 RC0001	1	500,000	100.0000	500,000
2	The Corporation of the City of London	NR	4			
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (09)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region . . .	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10) . . .	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada . . .	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures . . .	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment . . .	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children . . .	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . **101** 1 Yes ☐ 2 No ☒

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;
b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or
c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . **102** 1 Yes ☐ 2 No ☒

Contributions to agricultural organizations for SR&ED . . . **103** ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)			
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)		► 350	
Capital expenditures (from line 558 on Form T661)		360	
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . 385 1 Yes [ ] 2 No [X]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). . . . . 390 ______

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0".
If this amount is over $40 million, enter $40 million. . . . . 398 ______

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ____________

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ____________

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ... ____________

EE = [($7,000,000 **minus** (10**A**)) x (($40,000,000 **minus B**) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** ____________ Amount B **409** ____________

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable ____________ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ____________ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ____________ x Number of days in the tax year / 365 = 365 . . . . ____________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ____________

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 % =		J
Line 350 minus line 410 (if negative, enter "0")	430		x	20 % =		K
Line 410 minus line 350 (if negative, enter "0")			L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 % =		M
Line 360 minus line L (if negative, enter "0")	450		x	20 % =		N

Repayments (amount from line 370 in Part 8) . . . .

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 % =		
480		x	20 % =		
			Total	►	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) . . . .

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
	Subtotal		►	
ITC at the beginning of the tax year			520	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit	540			
Credit allocated from a partnership	550			
	Subtotal		►	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B2 in Part 30)	560			
Credit carried back to the previous year(s) (from Part 13)			P	
Credit transferred to offset Part VII tax liability	580			
	Subtotal		►	
Credit balance before refund				Q
Deduct:				
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)?	650	1 Yes [ ]	2 No [X]
Credit balance before refund (amount Q from Part 12)		R	
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S	
Refundable credits (amount R or S, whichever is less)*			T
Amount J from Part 11		U	
Subtract: Amount T or U, whichever is less			V
Net amount (if negative, enter "0")			W
Amount W x 40 %			X
Add: Amount V			Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)			Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)			AA
Amount J from Part 11		BB	
Subtract: Amount AA or BB, whichever is less			CC
Net amount (if negative, enter "0")			DD
Amount M from Part 11			EE
Amount DD or EE, whichever is less x 40 %			FF
Add : Amount CC above			GG
Refund of ITC (amounts FF **plus** GG)			HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	**B** Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	**C** Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	**E** ITC earned by the transferee for the qualified expenditures that were transferred **750**	**F** Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) ______ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826 ▶			VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			W W
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal			▶	
ITC at the beginning of the tax year			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (total of column 605)	640	6,000		
Credit allocated from a partnership	655			
Subtotal		6,000	▶	6,000
Total credit available				6,000
Deduct:				
Credit deducted from Part I tax (enter on line B4 in Part 30)	660			
Credit carried back to the previous year(s) (from Part 23)			DDD	
Subtotal			▶	
ITC closing balance from apprenticeship job creation expenditures			690	6,000

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year	715		EEE
Add: Specified child care start-up expenditures from the current tax year	705		FFF
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			GGG
Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG)	725		HHH
Excess (amount GGG **minus** amount HHH) (if negative, enter "0")			III
Add: Repayments of government and non-government assistance	735		JJJ
Total eligible expenditures for child care spaces (amount III **plus** amount JJJ)	745		

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal			▶	
ITC at the beginning of the tax year			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount MMM above)	780			
Credit allocated from a partnership	782			
Subtotal			▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B5 in Part 30)	785			
Credit carried back to the previous year(s) (from Part 27)			NNN	
Subtotal			▶	
ITC closing balance from child care spaces expenditures			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2010-12-31	Credit to be applied	941	
2nd previous tax year	2009-12-31	Credit to be applied	942	
3rd previous tax year	2008-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a)) . . . . **792** ______ ZZZ

In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:

The amount that can reasonably be considered to have been included in the original ITC . . . . **795** ______

25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property . . . . **797** ______

Amount from line 795 or line 797, whichever is less . . . . ______ OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC **799** ______ PPP

Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP
Enter amount QQQ on line A2 in Part 29. . . . . ______ QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17 . . . . ______ A1

Recaptured child care spaces ITC from line QQQ in Part 28 above . . . . ______ A2

Total recapture of investment tax credit – Add lines A1 and A2 . . . . ______ A3
Enter amount A3 on line 602 of the T2 return.

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5) . . . . ______ B1

ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12) . . . . ______ B2

ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19) . . . . ______ B3

ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22) . . . . ______ B4

ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26) . . . . ______ B5

Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) . . . . ______ B6
Enter amount B6 at line 652 of the T2 return.

Privacy Act, Personal Information Bank number CRA PPU 047

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
6,000				6,000

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				*
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				
1992-09-30				*
Total				

B+C+D+G **Total ITC utilized**

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	The Corporation of the City of London	NR			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		2,500,000			
Total taxable dividends paid in the tax year	100	2,500,000			
Total eligible dividends paid in the tax year			150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160		B
Excessive eligible dividend designation (line 150 **minus** line 160)					C
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			180		D
Subtotal (amount C **minus** amount D)					E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)			190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)					G
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			280		H
Subtotal (amount G **minus** amount H)					I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)			290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

Canada

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
London Hydro Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent	Year Month Day	**120** Ontario Corporation No.
Ontario		2000-04-26	1800266

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
111	Horton Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
London	ON	CA	N6A 4H6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Arnold (Last name) **451** David (First name)

454 ______________________, (Middle name(s))

460 1 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 [ ] Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 [ ] Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2012-12-31

Business number 86483 7430 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-01-31	125,243			125,243
2012-02-29	125,243			125,243
2012-03-31	125,243			125,243
2012-04-30	125,243			125,243
2012-05-31	125,243			125,243
2012-06-30	125,243			125,243
2012-07-31	125,243			125,243
2012-08-31	125,243			125,243
2012-09-30	125,243			125,243
2012-10-31	125,243			125,243
2012-11-30	125,243			125,243
2012-12-31	125,241			125,241
Total	1,502,914			1,502,914

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 86483 7430 RC0001

Corporation's name
002 London Hydro Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . 010 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 011 to 018.)
011 111 Horton Street
012
City: 015 London
Province, territory, or state: 016 ON
Country (other than Canada): 017
Postal code/Zip code: 018 N6A 4H6

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . 020 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 021 to 028.)
021 c/o
022
023
City: 025
Province, territory, or state: 026
Country (other than Canada): 027
Postal code/Zip code: 028

Location of books and records
Has the location of books and records changed since the last time we were notified? . . . . 030 1 Yes [ ] 2 No [X]
(If **yes**, complete lines 031 to 038.)
031 111 Horton Street
032
City: 035 London
Province,territory, or state: 036 ON
Country (other than Canada): 037
Postal code/Zip code: 038 N6A 4H6

040 **Type of corporation at the end of the tax year**
1 [X] Canadian-controlled private corporation (CCPC)
2 [ ] Other private corporation
3 [ ] Public corporation
4 [ ] Corporation controlled by a public corporation
5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ____ YYYY MM DD

To which tax year does this return apply?
Tax year start: 060 2011-01-01 (YYYY MM DD)
Tax year-end: 061 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:
subparagraph 88(2)(a)(iv)? . . . . 064 1 Yes [ ] 2 No [X]
subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:
Incorporation? . . . . 070 1 Yes [ ] 2 No [X]
Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada?
080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area
095 096

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300		5,469,972	A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			▶	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			5,469,972	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)	360		5,469,972	
Income exempt under paragraph 149(1)(t)	370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)			5,469,972	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	5,469,972	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	5,469,972	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 ***** 495,428 D / 11,250 = 22,019,022 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") 425 ______ F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % = 430 ______ G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*			5,469,972	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B		
Amount QQ from Part 13 of Schedule 27		C		
Personal service business income**	432	D		
Amount used to calculate the credit union deduction from Schedule 17		E		
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F		
Aggregate investment income from line 440 on page 6***		G		
Total of amounts B to G		▶		H
Amount A **minus** amount H (if negative, enter "0")			5,469,972	I

Amount I	5,469,972	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=	J
Amount I	5,469,972	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=	K
Amount I	5,469,972	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	= 629,047	L
Amount I	5,469,972	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=	M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M . . . . . 629,047 N
Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)				O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		P		
Amount QQ from Part 13 of Schedule 27		Q		
Personal service business income*	434	R		
Amount used to calculate the credit union deduction from Schedule 17		S		
Total of amounts P to S		▶		T
Amount O **minus** amount T (if negative, enter "0")				U

Amount U		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year 365	x	9 %	=	V
Amount U		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year 365	x	10 %	=	W
Amount U		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 365 / Number of days in the tax year 365	x	11.5 %	=	X
Amount U		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year 365	x	13 %	=	Y

General tax reduction – Total of amounts V to Y . . . . . Z
Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	**440** ______ x 26 2 / 3 % =			A
Foreign non-business income tax credit from line 632 on page 7				
Deduct: Foreign investment income from Schedule 7	**445** ______ x 9 1 / 3 % =			
	(if negative, enter "0")		▶	B
Amount A **minus** amount B (if negative, enter "0")				C
Taxable income from line 360 on page 3		5,469,972		
Deduct:				
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least				
Foreign non-business income tax credit from line 632 on page 7	x 25/9* 25 / 9 =			
Foreign business income tax credit from line 636 on page 7	x 1(0.38 - X**) 3.77358 =			
	▶			
		5,469,972		
		x 26 2 / 3 % =	1,458,659	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8)			896,545	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least		**450**		F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	**460**			
Deduct: Dividend refund for the previous tax year	**465**			
			▶	G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	**480**			
			▶	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H	**485**			

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3	2,500,000	x 1 / 3	833,333	I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8)				

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	2,078,589	A
Recapture of investment tax credit from Schedule 31			602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	5,469,972		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	5,469,972 ▶	5,469,972	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		2,078,589	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	546,997			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount N on page 5	638	629,047			
General tax reduction from amount Z on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	6,000			
Subtotal		1,182,044	▶	1,182,044	E

Part I tax payable – Line D **minus** line E	896,545	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	896,545
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		896,545

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	569,178	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		569,178 ▶	569,178
Total tax payable	770		1,465,723 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,800,000	
Total credits	890	1,800,000 ▶	1,800,000 B

Refund code 894 1 Overpayment 334,277

Balance (line A **minus** line B) -334,277

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid . . . .

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No ☒

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Arnold (Last name in block letters) 951 David (First name in block letters) 954 CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-06-22 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 661-5800 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes ☒ 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				7,873,000	A
Add:					
Provision for income taxes – current		101	1,527,000		
Interest and penalties on taxes		103	12,696		
Amortization of tangible assets		104	17,669,346		
Non-deductible meals and entertainment expenses		121	34,545		
Non-deductible company pension plans		124	776,100		
Subtotal of additions			20,019,687	20,019,687	
Other additions:					
Recapture of SR&ED expenditures – Form T661		231	94,873		
Miscellaneous other additions:					
600 Federal apprenticeship credit received re 2010		290	4,000		
603 Ontario apprentice tax credit	35,014				
Inducement - ITA 12(1)x)	6,918				
Total	41,932	293	41,932		
604 Unrealized SWAP adjustment	179,560				
Ontario Capital Tax expensed for accounting	72,948				
Income for tax purposes	1,839,120				
Total	2,091,628	294	2,091,628		
Subtotal of other additions		199	2,232,433	2,232,433	
Total additions		500	22,252,120	22,252,120	
Deduct:					
Gain on disposal of assets per financial statements		401	160,755		
Capital cost allowance from Schedule 8		403	23,498,903		
Cumulative eligible capital deduction from Schedule 10		405	43,664		
Subtotal of deductions			23,703,322	23,703,322	
Other deductions:					
Miscellaneous other deductions:					
700 Sale of scrap for accounting purposes		390	311,357		
701 Deductible expenses capitalized for accounting		391	530,328		
703 SRED refunds included in income for actg	70,141				
Total	70,141	393	70,141		
704 ATTC credits accrued for actg	40,000				
Total	40,000	394	40,000		
Subtotal of other deductions		499	951,826	951,826	
Total deductions		510	24,655,148	24,655,148	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				5,469,972	

T2 SCH 1 E (10)

Canada

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected			
Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230

Total (enter on line 402 of Schedule 1)

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

			Complete if payer corporation is connected		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270
					J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	The Corporation of the City of London	NR	2011-12-31	2,500,000	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 2,500,000

Total taxable dividends paid in the tax year to other than connected corporations	450	
Eligible dividends (included in line 450)	450a	
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)	460	2,500,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			2,500,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	2,500,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		►	
Total taxable dividends paid in the tax year that qualify for a dividend refund			2,500,000

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes	103		143		
Newfoundland and Labrador offshore	004 1 Yes	104		144		
Prince Edward Island	005 1 Yes	105		145		
Nova Scotia	007 1 Yes	107		147		
Nova Scotia offshore	008 1 Yes	108		148		
New Brunswick	009 1 Yes	109		149		
Quebec	011 1 Yes	111		151		
Ontario	013 1 Yes	113		153		
Manitoba	015 1 Yes	115		155		
Saskatchewan	017 1 Yes	117		157		
Alberta	019 1 Yes	119		159		
British Columbia	021 1 Yes	121		161		
Yukon	023 1 Yes	123		163		
Northwest Territories	025 1 Yes	125		165		
Nunavut	026 1 Yes	126		166		
Outside Canada	027 1 Yes	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
5,469,972		5,469,972	606,369

Ontario basic income tax (from Schedule 500)	270	642,609		
Deduct: Ontario small business deduction (from schedule 500)	402	36,240		
Subtotal		606,369	606,369	A6
Add:				
Surtax re Ontario small business deduction (from Schedule 500)	272			
Ontario additional tax re Crown royalties (from Schedule 504)	274			
Ontario transitional tax debits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Subtotal				B6
Subtotal (amount A6 **plus** amount B6)			606,369	C6
Deduct:				
Ontario resource tax credit (from Schedule 504)	404			
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario transitional tax credits (from Schedule 506)	414			
Ontario political contributions tax credit (from Schedule 525)	415			
Subtotal				D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")			606,369	E6
Deduct: Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")			606,369	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)	418			
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")			606,369	G6
Add:				
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282			
Subtotal				H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)			606,369	I6
Deduct:				
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	9,000		
Ontario apprenticeship training tax credit (from Schedule 552)	454	28,191		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario sound recording tax credit (from Schedule 562)	464			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Other Ontario tax credits				
Subtotal		37,191	37,191	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.	290		569,178	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits **255** 569,178

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	Buildings	8,347,620	625,653		0	312,827	8,660,446	4	0	0	346,418	8,626,855
2.	1	Distribution Equip	85,940,943			0		85,940,943	4	0	0	3,437,638	82,503,305
3.	2	Distribution Equip	38,376,751			0		38,376,751	6	0	0	2,302,605	36,074,146
4.	8	SM	16,580,599	554,772		0	277,386	16,857,985	20	0	0	3,371,597	13,763,774
5.	8	Equipment	3,924,459	4,444,846		0	2,222,423	6,146,882	20	0	0	1,229,376	7,139,929
6.	10	Vehicles/Computer b/f March 07	3,866,259	223,290		0	111,645	3,977,904	30	0	0	1,193,371	2,896,178
7.	12	SM Software	1,829,297	2,266,918		0	1,133,459	2,962,756	100	0	0	2,962,756	1,133,459
8.	12	Computer Software	1,491,659	2,481,132		0	1,240,566	2,732,225	100	0	0	2,732,225	1,240,566
9.	38	Back Hoes	403,218	181,113		0	90,557	493,774	30	0	0	148,132	436,199
10.	47		59,439,389	16,451,194		472,112	7,989,541	67,428,930	8	0	0	5,394,314	70,024,157
11.	50		62,854	406,298		0	203,149	266,003	55	0	0	146,302	322,850
12.	50	SM Computer		1,309		0	655	654	55	0	0	360	949
13.	43.2	Renewable Genration Equipment		935,237		0	467,619	467,618	50	0	0	233,809	701,428
		Totals	220,263,048	28,571,762		472,112	14,049,827	234,312,871				23,498,903	224,863,795

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (11)

Canada

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name	Country of residence (other than Canada)	Business number (see note 1)	Relationship code (see note 2)	Number of common shares you own	% of common shares you own	Number of preferred shares you own	% of preferred shares you own	Book value of capital stock
	100	200	300	400	500	550	600	650	700
1.	The Corporation of the City of Lond		NR	1	1,001	100.000			96,116

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 370,386 A

Add: Cost of eligible capital property acquired during the taxation year **222** 337,853

Other adjustments **226**

Subtotal (line 222 plus line 226) 337,853 x 3 / 4 = 253,390 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 253,390 ▶ 253,390 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 623,776 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . 623,776 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 623,776

less amount from line 249

Current year deduction . . . . 623,776 x 7.00 % = **250** 43,664 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 43,664 ▶ 43,664 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 580,112 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)				N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988		**400**		1
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)		**401**		2
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	**402**	3		
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	**408**	4		
Line 3 minus line 4 (if negative, enter "0")		▶		5
Total of lines 1, 2 and 5				6
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400		7		
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000		8		
Subtotal (line 7 plus line 8)	**409**	▶		9
Line 6 minus line 9 (if negative, enter "0")			▶	O
Line N minus line O (if negative, enter "0")				P
Line 5		x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")				R
Amount R		x 2 / 3 =		S
Amount N or amount O, whichever is less				T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)			**410**	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . . **050** Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	London Hydro Inc.	86483 7430 RC0001	1	500,000	100.0000	500,000	
2	The Corporation of the City of London	NR	4				
				Total	100.0000	500,000	**A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED . . . **103** ______

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 x 10 % = 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				Credit to be applied	901
2nd previous tax year				Credit to be applied	902
3rd previous tax year				Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) D

Refund (40 % of amount C or D, whichever is less) E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)			
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)		► 350	
Capital expenditures (from line 558 on Form T661)		360	
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? 385 1 Yes [ ] 2 No [X]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). 390 ______

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. 398 ______

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ... ________

EE = [($7,000,000 **minus** (10**A**)) x (($40,000,000 **minus B**) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** ________ Amount B **409** ________

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable ________ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ________ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ________ x $\frac{\text{Number of days in the tax year}}{365}$ 365 = ... ________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ________

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 % =		J
Line 350 minus line 410 (if negative, enter "0")	430		x	20 % =		K
Line 410 minus line 350 (if negative, enter "0")			L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 % =		M
Line 360 minus line L (if negative, enter "0")	450		x	20 % =		N

Repayments (amount from line 370 in Part 8) . . . .

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 % =			
480		x	20 % =			
			Total		▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) . . . .

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year					
Deduct:					
Credit deemed as a remittance of co-op corporations	510				
Credit expired	515				
	Subtotal		▶		
ITC at the beginning of the tax year			520		
Add:					
Credit transferred on amalgamation or wind-up of subsidiary	530				
Total current-year credit	540				
Credit allocated from a partnership	550				
	Subtotal		▶		
Total credit available					
Deduct:					
Credit deducted from Part I tax (enter on line B2 in Part 30)	560				
Credit carried back to the previous year(s) (from Part 13)			P		
Credit transferred to offset Part VII tax liability	580				
	Subtotal		▶		
Credit balance before refund					Q
Deduct:					
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610		
ITC closing balance on SR&ED			620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)?	650	1 Yes ☐	2 No ☒
Credit balance before refund (amount Q from Part 12)		R	
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S	
Refundable credits (amount R or S, whichever is less)*			T
Amount J from Part 11		U	
Subtract: Amount T or U, whichever is less			V
Net amount (if negative, enter "0")			W
Amount W ____ x 40 %			X
Add: Amount V			Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)			Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%.
Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)			AA
Amount J from Part 11		BB	
Subtract: Amount AA or BB, whichever is less			CC
Net amount (if negative, enter "0")			DD
Amount M from Part 11			EE
Amount DD or EE, whichever is less ____ x 40 %			FF
Add : Amount CC above			GG
Refund of ITC (amounts FF **plus** GG)			HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above 700	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) 710	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement 720	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition 730	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) 740
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred 750	F Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) ______ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) 760 ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826	▶		VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			W W
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
	Subtotal		▶	
ITC at the beginning of the tax year			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (total of column 605)	640	6,000		
Credit allocated from a partnership	655			
	Subtotal	6,000	▶	6,000
Total credit available				6,000
Deduct:				
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	6,000		
Credit carried back to the previous year(s) (from Part 23)			DDD	
	Subtotal	6,000	▶	6,000
ITC closing balance from apprenticeship job creation expenditures			690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year	715		EEE
Add: Specified child care start-up expenditures from the current tax year	705		FFF
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			GGG
Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG)	725		HHH
Excess (amount GGG **minus** amount HHH) (if negative, enter "0")			III
Add: Repayments of government and non-government assistance	735		JJJ
Total eligible expenditures for child care spaces (amount III **plus** amount JJJ)	745		

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal			▶	
ITC at the beginning of the tax year			775	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	777			
Total current-year credit (amount MMM above)	780			
Credit allocated from a partnership	782			
Subtotal			▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B5 in Part 30)	785			
Credit carried back to the previous year(s) (from Part 27)			NNN	
Subtotal			▶	
ITC closing balance from child care spaces expenditures			790	

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2010-12-31	Credit to be applied	941	
2nd previous tax year	2009-12-31	Credit to be applied	942	
3rd previous tax year	2008-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))		792		ZZZ
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:				
The amount that can reasonably be considered to have been included in the original ITC	795			
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797			
Amount from line 795 or line 797, whichever is less				OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC	799		PPP
Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP Enter amount QQQ on line A2 in Part 29.			QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)		B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	6,000	B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	6,000	B6

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Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

	Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
	6,000	6,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				*
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				
1992-09-30				*
Total				

B+C+D+G **Total ITC utilized** 6,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

Canada Revenue Agency Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number (If a corporation is not registered, enter "NR")	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	The Corporation of the City of London	NR			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	49,267,462	A
Taxable income for the year (DICs enter "0") *	110	5,469,972	B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130				
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140				
Subtotal (**add** lines 120, 130, and 140)		►	C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	5,469,972			
After-tax income (line 150 x general rate factor for the tax year ** 0.7)			190	3,828,980	D
Eligible dividends received in the tax year	200				
Dividends deductible under section 113 received in the tax year	210				
Subtotal (**add** lines 200 and 210)			►		E
GRIP addition:					
Becoming a CCPC (line PP from Part 4)	220				
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230				
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240				
Subtotal (**add** lines 220, 230, and 240)			► 290		F
Subtotal (**add** lines A, D, E, and F)				53,096,442	G
Eligible dividends paid in the previous tax year	300				
Excessive eligible dividend designations made in the previous tax year	310				

Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.

Subtotal (line 300 **minus** line 310)		►		H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)		490	53,096,442	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)		560		
GRIP at the end of the tax year (line 490 **minus** line 560)		590	53,096,442	

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year			7,757,111	J1	
Enter the following amounts before specified future tax consequences from the current tax year:					
Income for the credit union deduction (amount E in Part 3 of Schedule 17)		K1			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less		L1			
Aggregate investment income (line 440 of the T2 return)		M1			
Subtotal (**add** lines K1, L1, and M1)		►		N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")			7,757,111 ►	7,757,111	O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R1

Aggregate investment income (line 440 of the T2 return) . . . . ______ S1

Subtotal (**add** lines Q1, R1, and S1) ______ ► ______ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ______ ► ______ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ______ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.7) . . . . **500** ______

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 10,288,016 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Subtotal (**add** lines K2, L2, and M2) ______ ► ______ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 10,288,016 ► 10,288,016 O2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R2

Aggregate investment income (line 440 of the T2 return) . . . . ______ S2

Subtotal (**add** lines Q2, R2, and S2) ______ ► ______ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ______ ► ______ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ______ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) . . . . **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 13,570,105 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ► ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 13,570,105 ► 13,570,105 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ► ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ► ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.7) . . . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ► ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ______ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ______ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ______
Net capital losses . . . . ______
Farm losses . . . . ______
Restricted farm losses . . . . ______
Limited partnership losses . . . . ______

Subtotal ______ ► ______ HH

Subtotal (**add** lines FF, GG, and HH) ______ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ______ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ______ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ______ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ______ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ______ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ______ ► ______ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ______ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	. . . . =		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	. . . . =		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365 / 365	. . . . =	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	. . . . =		TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.70000 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		2,500,000	
Total taxable dividends paid in the tax year	100	2,500,000	
Total eligible dividends paid in the tax year	150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160	53,096,442	B
Excessive eligible dividend designation (line 150 **minus** line 160)			C
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	180		D
Subtotal (amount C **minus** amount D)			E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)	190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	200		
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)			G
Deduct:			
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*	280		H
Subtotal (amount G **minus** amount H)			I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)	290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	14.00 %	=	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	12.00 %	=	5.95068 %	A2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	11.50 %	=	5.79726 %	A3

Ontario basic rate of tax for the year (total of rates A1 to A3) 11.74794 ► 11.74794 % A4

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income* . . . . 5,469,972 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A4 from Part 1) . . . . 642,609 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)				5,469,972	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)				5,469,972	2
Federal business limit before the application of subsection 125(5.1) * (amount from line 410 of the T2 return)		x	=	500,000	3
		line 4 on page 4 of the T2 return			
Enter the least of amounts 1, 2, and 3				500,000	D

Ontario domestic factor: Ontario taxable income ** / taxable income earned in all provinces and territories *** = 5,469,972.00 / 5,469,972 = 1.00000 E

Amount D x amount E	500,000	a
Ontario taxable income (amount B from Part 2)	5,469,972	b

Ontario small business income (lesser of amount a and amount b) .... 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	8.50 %	= %	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	7.50 %	= 3.71918 %	G2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	7.00 %	= 3.52877 %	G3

OSBD rate for the year (total of rates G1 to G3) .... 7.24795 % G4

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G4) .... 36,240 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule. Otherwise, complete the calculation for this line.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income *		I
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)		J
Aggregate adjusted taxable income (amount I **plus** amount J) ▶		K
Deduct:		
Ontario business limit	500,000	
Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P)		L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 / Number of days in the tax year 365 x 4.25 % = % M

Amount L **multiplied by** % on line M =		N

Amount N ______ x Ontario small business income (amount F from Part 3) 500,000 / 500,000 = | | O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3)		P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3	500,000	Q

Surtax payable (amount P from Part 4) / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 7.24795 % = ______ / 0.07248 = ______ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0")	500,000	S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			T
Deduct:			
Ontario adjusted small business income (amount S from Part 5)			U
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V
OSBD rate for the year (rate G6 from Part 3)	7.24795 %		
Amount V **multiplied** by the OSBD rate for the year			W
Ontario domestic factor (amount E from Part 3)		1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)			Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 501

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations* 100	Business number of associated corporations** 200	Tax year-end 300	Adjusted taxable income *** (if loss, enter "0") 400
1	The Corporation of the City of London	NR	2011-12-31	
			Total 500	

Enter the total adjusted taxable income from line 500 on line J in Part 4 of Schedule 500, *Ontario Corporation Tax Calculation.*

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

***** Rules for adjusted taxable income:**

– If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.

– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.

– If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365, and **divide** by the total number of days in all of those tax years.

T2 SCH 501 E (10)

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
London Hydro Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-04-26	1800266

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
111	Horton Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
London	ON	CA	N6A 4H6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Arnold (Last name) **451** David (First name)

454 ______________________ , (Middle name(s))

460 [1] Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	120 Telephone number including area code
David Arnold	(519) 661-5800

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		15.000 %	12,384	30.000 %		18
2.		15.000 %	11,063	30.000 %		11
3.		15.000 %	12,530	30.000 %		18

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,715	3,000	3,000		3,000
2.	3,319	3,000	3,000		3,000
3.	3,759	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 ..... 9,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ______ x percentage on line 170 in Part 1 ______ % = ... ______ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

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SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  – paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  – for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  – for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  – the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  – it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  – the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  – the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	120 Telephone number including area code
David Arnold	(519) 661-5800

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		147	147	4,027
2.		365	365	10,000
3.		365	365	10,000
4.		152	152	4,164

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		83,232	83,232	29,131
2.		63,652	63,652	22,278
3.		66,726	66,726	23,354
4.		24,895	24,895	8,713

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	4,027		4,027
2.	10,000		10,000
3.	10,000		10,000
4.	4,164		4,164

Ontario apprenticeship training tax credit (total of amounts in column N) 500 28,191 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2012-12-31

Business number 86483 7430 RC0001

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2012-01-31	125,243			125,243
2012-02-29	125,243			125,243
2012-03-31	125,243			125,243
2012-04-30	125,243			125,243
2012-05-31	125,243			125,243
2012-06-30	125,243			125,243
2012-07-31	125,243			125,243
2012-08-31	125,243			125,243
2012-09-30	125,243			125,243
2012-10-31	125,243			125,243
2012-11-30	125,243			125,243
2012-12-31	125,241			125,241
Total	1,502,914			1,502,914

Canada Revenue Agency / Agence du revenu du Canada

200

T2 CORPORATION INCOME TAX RETURN

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre or tax services office. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) **001** 86483 7430 RC0001

Corporation's name

002 London Hydro Inc.

Address of head office

Has this address changed since the last time we were notified? . . . . **010** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 011 to 018.)

011 111 Horton Street

012

City	Province, territory, or state
015 London	**016** ON
Country (other than Canada)	Postal code/Zip code
017	**018** N6A 4H6

Mailing address (if different from head office address)

Has this address changed since the last time we were notified? . . . . **020** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 021 to 028.)

021 c/o

022

023

City	Province, territory, or state
025	**026**
Country (other than Canada)	Postal code/Zip code
027	**028**

Location of books and records

Has the location of books and records changed since the last time we were notified? . . . . **030** 1 Yes ☐ 2 No ☒

(If **yes**, complete lines 031 to 038.)

031 111 Horton Street

032

City	Province,territory, or state
035 London	**036** ON
Country (other than Canada)	Postal code/Zip code
037	**038** N6A 4H6

040 **Type of corporation at the end of the tax year**

1 ☒ Canadian-controlled private corporation (CCPC)

2 ☐ Other private corporation

3 ☐ Public corporation

4 ☐ Corporation controlled by a public corporation

5 ☐ Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ________ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2011-01-01 (YYYY MM DD)

Tax year-end **061** 2011-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes ☐ 2 No ☒

If **yes**, provide the date control was acquired . . . . **065** ________ YYYY MM DD

Is the date on line 061 a deemed tax year-end according to:

subparagraph 88(2)(a)(iv)? . . . . **064** 1 Yes ☐ 2 No ☒

subsection 249(3.1)? . . . . **066** 1 Yes ☐ 2 No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes ☐ 2 No ☒

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes ☐ 2 No ☒

Amalgamation? . . . . **071** 1 Yes ☐ 2 No ☒

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes ☐ 2 No ☒

Is this the final return up to dissolution? . . . . **078** 1 Yes ☐ 2 No ☒

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada?

080 1 Yes ☒ 2 No ☐ If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes ☐ 2 No ☒

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085

1 ☐ Exempt under paragraph 149(1)(e) or (l)

2 ☐ Exempt under paragraph 149(1)(j)

3 ☐ Exempt under paragraph 149(1)(t)

4 ☐ Exempt under other paragraphs of section 149

Do not use this area

095 **096**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) does the corporation have aggregate investment income at line 440?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210	X	10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

		Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

		1 Yes	2 No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270		X
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution US

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity Distribution	285	100.000 %
286		287	%
288		289	%

		1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible 294 ________ YYYY MM DD

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? 295 1 Yes ☐ 2 No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	5,469,972	A
Deduct: Charitable donations from Schedule 2	311				
Gifts to Canada, a province, or a territory from Schedule 2	312				
Cultural gifts from Schedule 2	313				
Ecological gifts from Schedule 2	314				
Gifts of medicine from Schedule 2	315				
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320				
Part VI.1 tax deduction*	325				
Non-capital losses of previous tax years from Schedule 4	331				
Net capital losses of previous tax years from Schedule 4	332				
Restricted farm losses of previous tax years from Schedule 4	333				
Farm losses of previous tax years from Schedule 4	334				
Limited partnership losses of previous tax years from Schedule 4	335				
Taxable capital gains or taxable dividends allocated from a central credit union	340				
Prospector's and grubstaker's shares	350				
Subtotal			►		B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				5,469,972	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355		D
Taxable income (amount C **plus** amount D)			360	5,469,972	
Income exempt under paragraph 149(1)(t)			370		
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				5,469,972	Z

* This amount is equal to 3.2 times the Part VI.1 tax payable at line 724 on page 8. Use 3.5 for tax years ending after 2011.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7	400	5,469,972	A
Taxable income from line 360 on page 3, **minus** 100/28* 3.37312 of the amount on line 632** on page 7, **minus** 1/(0.38 - X***) 3.77358 times the amount on line 636**** on page 7, and **minus** any amount that, because of federal law, is exempt from Part I tax	405	5,469,972	B
Business limit (see notes 1 and 2 below)	410	500,000	C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C 500,000 x 415 ***** 495,428 D / 11,250 = 22,019,022 E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0")	425		F

Small business deduction

Amount A, B, C, or F, whichever is the least ______ x 17 % =	430		G

Enter amount G on line 1 on page 7.

* 10/3 for tax years ending before November 1, 2011. The result of the multiplication by line 632 has to be pro-rated based on the number of days in the tax year that are in each period: before November 1, 2011, and after October 31, 2011.

** Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

*** General rate reduction percentage for the tax year. It has to be pro-rated based on the number of days in the tax year that are in each calendar year. See page 5.

**** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

***** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3*		5,469,972	A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Personal service business income**	432	D	
Amount used to calculate the credit union deduction from Schedule 17		E	
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least		F	
Aggregate investment income from line 440 on page 6***		G	
Total of amounts B to G		▶	H
Amount A **minus** amount H (if negative, enter "0")		5,469,972	I

Amount I	5,469,972	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	J
Amount I	5,469,972	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	K
Amount I	5,469,972	x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	= 629,047	L
Amount I	5,469,972	x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	M

General tax reduction for Canadian-controlled private corporations – Total of amounts J to M ... 629,047 N
Enter amount N on line 638 on page 7.

* For tax years ending after October 31, 2011, line 360 or amount Z, whichever applies.
** For tax years beginning after October 31, 2011.
*** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)			O
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		P	
Amount QQ from Part 13 of Schedule 27		Q	
Personal service business income*	434	R	
Amount used to calculate the credit union deduction from Schedule 17		S	
Total of amounts P to S		▶	T
Amount O **minus** amount T (if negative, enter "0")			U

Amount U		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	V
Amount U		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	W
Amount U		x	Number of days in the tax year after December 31, 2010, and before January 1, 2012 / Number of days in the tax year	365 / 365	x	11.5 %	=	X
Amount U		x	Number of days in the tax year after December 31, 2011 / Number of days in the tax year	/ 365	x	13 %	=	Y

General tax reduction – Total of amounts V to Y ... Z
Enter amount Z on line 639 on page 7.

* For tax years beginning after October 31, 2011.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ________ x 26 2 / 3 % = ... ________ A

Foreign non-business income tax credit from line 632 on page 7 . . . . ________

Deduct:
Foreign investment income from Schedule 7 . . . . **445** ________ x 9 1 / 3 % = ________
(if negative, enter "0") ________ ▶ ________ B

Amount A **minus** amount B (if negative, enter "0") . . . . ________ C

Taxable income from line 360 on page 3 5,469,972

Deduct:
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least . . . . ________

Foreign non-business income tax credit from line 632 on page 7 . . . ________ x 25/9* 25 / 9 = ________

Foreign business income tax credit from line 636 on page 7 . . . . ________ x 1(0.38 - X**) 3.77358 = ________

________ ▶ ________

5,469,972

x 26 2 / 3 % = 1,458,659 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 8) . . . . 896,545 E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ________ F

* 100/35 for tax years beginning after October 31, 2011.

** General rate reduction percentage for the tax year. It has to be pro-rated.

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ________

Deduct: Dividend refund for the previous tax year . . . . **465** ________

________ ▶ ________ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ________

Total Part IV tax payable from Schedule 3 . . . . ________

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ________

________ ▶ ________ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ________

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 on page 2 of Schedule 3 . . . . 2,500,000 x 1 / 3 833,333 I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ________ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784 on page 8) . . . . ________

Part I tax

Base amount of Part I tax – Taxable income from page 3 (line 360 or amount Z, whichever applies) **multiplied** by 38 %			550	2,078,589	A
Recapture of investment tax credit from Schedule 31			602		B

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6			i
Taxable income from line 360 on page 3	5,469,972		
Deduct:			
Amount from line 400, 405, 410, or 425 on page 4, whichever is the least			
Net amount	5,469,972 ▶	5,469,972	ii

Refundable tax on CCPC's investment income – 6 2/3 % of whichever is less: amount i or ii	604		C
Subtotal (**add** lines A to C)		2,078,589	D

Deduct:

Small business deduction from line 430 on page 4			1		
Federal tax abatement	608	546,997			
Manufacturing and processing profits deduction from Schedule 27	616				
Investment corporation deduction	620				
Taxed capital gains 624					
Additional deduction – credit unions from Schedule 17	628				
Federal foreign non-business income tax credit from Schedule 21	632				
Federal foreign business income tax credit from Schedule 21	636				
General tax reduction for CCPCs from amount N on page 5	638	629,047			
General tax reduction from amount Z on page 5	639				
Federal logging tax credit from Schedule 21	640				
Federal qualifying environmental trust tax credit	648				
Investment tax credit from Schedule 31	652	6,000			
Subtotal		1,182,044	▶	1,182,044	E

Part I tax payable – Line D **minus** line E	896,545	F

Enter amount F on line 700 on page 8.

Summary of tax and credits

Federal tax

Part I tax payable from page 7	700	896,545
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		896,545

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	569,178	
Provincial tax on large corporations (Nova Scotia Schedule 342)	765		
		569,178 ▶	569,178
Total tax payable	770		1,465,723 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from page 6	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	1,800,000	
Total credits	890	1,800,000 ▶	1,800,000 B

Refund code 894 1 Overpayment 334,277

Balance (line A **minus** line B) -334,277

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No X

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 Arnold (Last name in block letters) 951 David (First name in block letters) 954 CFO (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2012-06-22 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (519) 661-5800 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes X 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				7,873,000 A
Add:				
Provision for income taxes – current		101	1,527,000	
Interest and penalties on taxes		103	12,696	
Amortization of tangible assets		104	17,669,346	
Non-deductible meals and entertainment expenses		121	34,545	
Non-deductible company pension plans		124	776,100	
Subtotal of additions			20,019,687 ▶	20,019,687
Other additions:				
Recapture of SR&ED expenditures – Form T661		231	94,873	
Miscellaneous other additions:				
600 Federal apprenticeship credit received re 2010		290	4,000	
603 Ontario apprentice tax credit	35,014			
Inducement - ITA 12(1)x)	6,918			
Total	41,932	293	41,932	
604 Unrealized SWAP adjustment	179,560			
Ontario Capital Tax expensed for accounting	72,948			
Income for tax purposes	1,839,120			
Total	2,091,628	294	2,091,628	
Subtotal of other additions		199	2,232,433 ▶	2,232,433
Total additions		500	22,252,120 ▶	22,252,120
Deduct:				
Gain on disposal of assets per financial statements		401	160,755	
Capital cost allowance from Schedule 8		403	23,498,903	
Cumulative eligible capital deduction from Schedule 10		405	43,664	
Subtotal of deductions			23,703,322 ▶	23,703,322
Other deductions:				
Miscellaneous other deductions:				
700 Sale of scrap for accounting purposes		390	311,357	
701 Deductible expenses capitalized for accounting		391	530,328	
703 SRED refunds included in income for actg	70,141			
Total	70,141	393	70,141	
704 ATTC credits accrued for actg	40,000			
Total	40,000	394	40,000	
Subtotal of other deductions		499	951,826 ▶	951,826
Total deductions		510	24,655,148 ▶	24,655,148
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				5,469,972

Canada Revenue Agency / Agence du revenu du Canada

DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid in the tax year that qualify for a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a tax year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- "X" under column A if dividend received from a foreign source (connected corporation only).
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

Do not include dividends received from foreign non-affiliates.

		Complete if payer corporation is connected			
Name of payer corporation (from which the corporation received the dividend) 200	A	B Enter 1 if payer corporation is connected 205	C Business Number of connected corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
				Total (enter on line 402 of Schedule 1)	

Note: If your corporation's tax year-end is different than that of the connected payer corporation, your corporation could have received dividends from more than one tax year of the payer corporation. If so, use a separate line to provide the information for each tax year of the payer corporation.

			Complete if payer corporation is connected		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d)* 240	F1 Eligible dividends (included in column F)	F2	G Total taxable dividends paid by connected payer corporation (for tax year in column D) 250	H Dividend refund of the connected payer corporation (for tax year in column D)** 260	I Part IV tax before deductions F x 1 / 3 *** 270
					J

Total (enter the amount from column F on line 320 of the T2 return and amount J in Part 2)

* If taxable dividends are received, enter the amount in column 240, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column 270. Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

** If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

*** For dividends received from connected corporations: Part IV tax = $\frac{\text{Column F x Column H}}{\text{Column G}}$

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

	A	B	C	D	D1
	Name of connected recipient corporation 400	Business Number 410	Tax year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430	Eligible dividends (included in column D)
1	The Corporation of the City of London	NR	2011-12-31	2,500,000	

Note

If your corporation's tax year-end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information for each tax year of the recipient corporation.

Total 2,500,000

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends (included in line 450)	450a		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column D above **plus** line 450)		460	2,500,000

Part 4 – Total dividends paid in the tax year

Complete this part if the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460 above) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			2,500,000
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	2,500,000
Deduct:			
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal		▶	
Total taxable dividends paid in the tax year that qualify for a dividend refund			2,500,000

Canada Revenue Agency — Agence du revenu du Canada

SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1);
  - is claiming provincial or territorial tax credits or rebates (see Part 2); or
  - has to pay taxes, other than income tax, for Newfoundland and Labrador, or Ontario (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 ______ Enter the Regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2*** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☐	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking centre: the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in calculating the corporation's income under section 33.1 of the federal *Income Tax Act*.

*** For corporations other than those described under Regulation 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the *T2 Corporation – Income Tax Guide*.
2. If the corporation has provincial or territorial tax payable, complete Part 2.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
5,469,972		5,469,972	606,369

	Line	Amount		Amount	
Ontario basic income tax (from Schedule 500)	270	642,609			
Deduct: Ontario small business deduction (from schedule 500)	402	36,240			
Subtotal		606,369	▶	606,369	A6
Add:					
Surtax re Ontario small business deduction (from Schedule 500)	272				
Ontario additional tax re Crown royalties (from Schedule 504)	274				
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal			▶		B6
Subtotal (amount A6 **plus** amount B6)				606,369	C6
Deduct:					
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario transitional tax credits (from Schedule 506)	414				
Ontario political contributions tax credit (from Schedule 525)	415				
Subtotal			▶		D6
Subtotal (amount C6 **minus** amount D6) (if negative, enter "0")				606,369	E6
Deduct: Ontario research and development tax credit (from Schedule 508)			416		
Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0")				606,369	F6
Deduct: Ontario corporate minimum tax credit (from schedule 510)			418		
Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0")				606,369	G6
Add:					
Ontario corporate minimum tax (from Schedule 510)	278				
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies)	282				
Subtotal			▶		H6
Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6)				606,369	I6
Deduct:					
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452	9,000			
Ontario apprenticeship training tax credit (from Schedule 552)	454	28,191			
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario sound recording tax credit (from Schedule 562)	464				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Other Ontario tax credits					
Subtotal		37,191	▶	37,191	J6
Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) (if a credit, enter a negative amount) Include this amount on line 255.			290	569,178	K6

Summary

Enter the total net tax payable or refundable credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable credits	**255**	569,178

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number (See Note) 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % **** 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (for declining balance method, column 7 **multiplied** by column 8, or a lower amount) (line 403 of Schedule 1) ***** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1.	1	Buildings	8,347,620	625,653		0	312,827	8,660,446	4	0	0	346,418	8,626,855
2.	1	Distribution Equip	85,940,943			0		85,940,943	4	0	0	3,437,638	82,503,305
3.	2	Distribution Equip	38,376,751			0		38,376,751	6	0	0	2,302,605	36,074,146
4.	8	SM	16,580,599	554,772		0	277,386	16,857,985	20	0	0	3,371,597	13,763,774
5.	8	Equipment	3,924,459	4,444,846		0	2,222,423	6,146,882	20	0	0	1,229,376	7,139,929
6.	10	Vehicles/Computer b/f March 07	3,866,259	223,290		0	111,645	3,977,904	30	0	0	1,193,371	2,896,178
7.	12	SM Software	1,829,297	2,266,918		0	1,133,459	2,962,756	100	0	0	2,962,756	1,133,459
8.	12	Computer Software	1,491,659	2,481,132		0	1,240,566	2,732,225	100	0	0	2,732,225	1,240,566
9.	38	Back Hoes	403,218	181,113		0	90,557	493,774	30	0	0	148,132	436,199
10.	47		59,439,389	16,451,194		472,112	7,989,541	67,428,930	8	0	0	5,394,314	70,024,157
11.	50		62,854	406,298		0	203,149	266,003	55	0	0	146,302	322,850
12.	50	SM Computer		1,309		0	655	654	55	0	0	360	949
13.	43.2	Renewable Genration Equipment		935,237		0	467,619	467,618	50	0	0	233,809	701,428
		Totals	220,263,048	28,571,762		472,112	14,049,827	234,312,871				23,498,903	224,863,795

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) **plus** or **minus** certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** Enter a rate only, if you are using the declining balance method. For any other method (for example the straignt-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 11.

***** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	The Corporation of the City of Lond		NR	1	1,001	100.000			96,116

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

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Canada

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SCHEDULE 10

CUMULATIVE ELIGIBLE CAPITAL DEDUCTION

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- For use by a corporation that has eligible capital property. For more information, see the *T2 Corporation Income Tax Guide*.
- A separate cumulative eligible capital account must be kept for each business.

Part 1 – Calculation of current year deduction and carry-forward

Cumulative eligible capital - Balance at the end of the preceding taxation year (if negative, enter "0") **200** 370,386 A

Add: Cost of eligible capital property acquired during the taxation year **222** 337,853

Other adjustments **226**

Subtotal (line 222 plus line 226) 337,853 x 3 / 4 = 253,390 B

Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an eligible capital property to the corporation after December 20, 2002 . . **228** x 1 / 2 = C

amount B minus amount C (if negative, enter "0") 253,390 ▶ 253,390 D

Amount transferred on amalgamation or wind-up of subsidiary . . . . **224** E

Subtotal (add amounts A, D, and E) **230** 623,776 F

Deduct: Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all eligible capital property during the taxation year . . . . **242** G

The gross amount of a reduction in respect of a forgiven debt obligation as provided for in subsection 80(7) . . . . . **244** H

Other adjustments . . . . **246** I

(add amounts G,H, and I) x 3 / 4 = **248** J

Cumulative eligible capital balance (amount F minus amount J) . . . . 623,776 K

(if amount K is negative, enter "0" at line M and proceed to Part 2)

Cumulative eligible capital for a property no longer owned after ceasing to carry on that business **249**

amount K 623,776

less amount from line 249

Current year deduction . . . . 623,776 x 7.00 % = **250** 43,664 *

(line 249 plus line 250) (enter this amount at line 405 of Schedule 1) 43,664 ▶ 43,664 L

Cumulative eligible capital – Closing balance (amount K minus amount L) (if negative, enter "0") . . . . . **300** 580,112 M

* You can claim any amount up to the maximum deduction of 7%. The deduction may not exceed the maximum amount prorated by the number of days in the taxation year divided by 365.

Part 2 – Amount to be included in income arising from disposition

(complete this part only if the amount at line K is negative)

Amount from line K (show as positive amount)						N
Total of cumulative eligible capital (CEC) deductions from income for taxation years beginning after June 30, 1988			400		1	
Total of all amounts which reduced CEC in the current or prior years under subsection 80(7)			401		2	
Total of CEC deductions claimed for taxation years beginning before July 1, 1988	402		3			
Negative balances in the CEC account that were included in income for taxation years beginning before July 1, 1988	408		4			
Line 3 minus line 4 (if negative, enter "0")			▶		5	
Total of lines 1, 2 and 5					6	
Amounts included in income under paragraph 14(1)(b), as that paragraph applied to taxation years ending after June 30, 1988 and before February 28, 2000, to the extent that it is for an amount described at line 400			7			
Amounts at line T from Schedule 10 of previous taxation years ending after February 27, 2000			8			
Subtotal (line 7 plus line 8)	409		▶		9	
Line 6 minus line 9 (if negative, enter "0")					▶	O
Line N minus line O (if negative, enter "0")						P
Line 5				x 1 / 2 =		Q
Line P minus line Q (if negative, enter "0")						R
Amount R				x 2 / 3 =		S
Amount N or amount O, whichever is less						T
Amount to be included in income (amount S plus amount T) (enter this amount on line 108 of Schedule 1)					410	

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless code 5 applies)
2 – CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 – Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 – Associated non-CCPC
5 – Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . . **050** Year 2011

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes ☐ 2 No X

	1 Names of associated corporations **100**	2 Business Number of associated corporations **200**	3 Association code **300**	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**
1	London Hydro Inc.	86483 7430 RC0001	1	500,000	100.0000	500,000
2	The Corporation of the City of London	NR	4			
				Total	100.0000	500,000 A

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

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SCHEDULE 31

INVESTMENT TAX CREDIT – CORPORATIONS

General information

1. For use by a corporation that during a tax year:
   - earned an investment tax credit (ITC);
   - is claiming a deduction against its Part I tax payable;
   - is claiming a refund of credit earned during the current tax year;
   - is claiming a carryforward of credit from previous tax years;
   - is transferring a credit following an amalgamation or wind-up of a subsidiary, as described under subsections 87(1) and 88(1) of the federal *Income Tax Act;*
   - is requesting a credit carryback; or
   - is subject to a recapture of ITC.
2. References to parts, sections, and subsections on this schedule are from the federal *Income Tax Act* and the federal *Income Tax Regulations*. References to interpretation bulletins and information circulars are to the latest versions.
3. The ITC is eligible for a three-year carryback (if not deductible in the year earned). It is also eligible for a twenty-year carryforward.
4. Investments or expenditures, as defined in subsection 127(9) and Part XLVI of the federal *Income Tax Regulations*, that earn the ITC are:
   - qualified property (Parts 4 to 7);
   - expenditures that are part of the SR&ED qualified expenditure pool (Parts 8 to 17). Complete and file Form T661, *Scientific Research and Experimental Development (SR&ED) Expenditures Claim*;
   - pre-production mining expenditures (Parts 18 to 20);
   - apprenticeship job creation expenditures (Parts 21 to 23); and
   - child care spaces expenditures (Parts 24 to 28).
5. Attach a completed copy of this schedule with the *T2 Corporation Income Tax Return.*
6. For more information on ITCs, see the section called "Investment Tax Credit" in the *T2 Corporation – Income Tax Guide*, Information Circular IC 78-4, *Investment Tax Credit Rates,* and its related Special Release. Also, see Interpretation Bulletin IT-151, *Scientific Research and Experimental Development Expenditures.*
7. For information on SR&ED, see Interpretation Bulletin IT-151 (**consolidated**), *Scientific Research and Experimental Development Expenditures*; Information Circular 86-4, *Scientific Research and Experimental Development*; Brochure RC4472, *Overview of the Scientific Research and Experimental Development Program (SR&ED) Tax Incentive Program*; Brochure RC4467, *Support for your R&D in Canada* and T4088, *Guide to Form T661 Scientific Research and Experimental Development (SR&ED) Expenditures Claim*.

Detailed information

1. For the purpose of this schedule, **"investment"** means:
   The capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property when it files the income tax return for the year in which the property was acquired.
2. An ITC deducted or refunded in a tax year for a depreciable property, other than a depreciable property deductible under paragraph 37(1)(b), reduces the capital cost of that property in the next tax year. It also reduces the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
3. Property acquired has to be "available for use" before a claim for an ITC can be made.
4. Expenditures for SR&ED and capital costs for a property qualifying for an ITC must be identified by the claimant on Form T661 and Schedule 31 no later than 12 months after the claimant's income tax return is due for the tax year in which the expenditures or capital costs were incurred.
5. Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITC's is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 of the Act is not applicable for the agreement to share any income or loss. Special rules apply to specified and limited partners. For more information, see Guide T4068-1, 2010 Supplement to the 2006 T4068, Guide for the T5013 Partnership Information Return.
6. For SR&ED expenditures, the expression "in Canada" includes the "exclusive economic zone" (as defined in the *Oceans Act* to generally consist of an area that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil for that zone.

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

Part 1 – Investments, expenditures and percentages

	Specified percentage
Investments	
Qualified property acquired primarily for use in Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick, the Gaspé Peninsula, or a prescribed offshore region	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than the corporation's expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 20 % rate.	
If you are a corporation that is not a CCPC that incurred qualified expenditures for SR&ED in any area in Canada	20 %
If you are a taxable Canadian corporation that incurred pre-production mining expenditures	10 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
If you incurred eligible expenditures after March 18, 2007, for the creation of licensed child care spaces for the children of your employees and, potentially, for other children	25 %

Part 2 – Determination of a qualifying corporation

Is the corporation a qualifying corporation? . . . . . **101** 1 Yes [ ] 2 No [X]

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and the taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC calculating a refundable ITC, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of both corporations; and
- one of the corporations has at least one shareholder who is not common to both corporations.

If you are a **qualifying** corporation, you will earn a **100%** refund on your share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100%** refund on their share of any ITCs earned at the 35% rate on qualified **current** expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified **capital** expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

The 100% refund will not be available to a corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to:

a) one or more persons exempt from Part I tax under section 149;

b) Her Majesty in right of a province, a Canadian municipality, or any other public authority; or

c) any combination of persons referred to in a) or b) above.

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** 1 Yes [ ] 2 No [X]

Contributions to agricultural organizations for SR&ED . . . . . **103** ____________

If **yes**, complete Schedule 125, *Income Statement Information*, to identify the type of farming industry the corporation is involved in. For more information on Schedule 125, see the *Guide to the General Index of Financial Information (GIFI) for Corporations.* Enter contributions on line 350 of Part 8.

QUALIFIED PROPERTY

Part 4 – Eligible investments for qualified property from the current tax year

	CCA* class number 105	Description of investment 110	Date available for use 115	Location used (province or territory) 120	Amount of investment 125
1.					

* CCA: capital cost allowance

Total investment – enter in formula on line 240 in Part 5

Part 5 – Calculation of current-year credit and account balances – ITC from investments in qualified property

ITC at the end of the previous tax year . . . . .

Deduct:

Credit deemed as a remittance of co-op corporations 210

Credit expired 215

Subtotal ▶

ITC at the beginning of the tax year 220

Add:

Credit transferred on amalgamation or wind-up of subsidiary 230

ITC from repayment of assistance 235

Total current-year credit: total of column 125 x 10 % = ... 240

Credit allocated from a partnership 250

Subtotal ▶

Total credit available . . . . .

Deduct:

Credit deducted from Part I tax (enter on line B1 in Part 30) 260

Credit carried back to the previous year(s) (from Part 6) . . . . . A

Credit transferred to offset Part VII tax liability 280

Subtotal ▶

Credit balance before refund . . . . . B

Deduct:

Refund of credit claimed on investments from qualified property (from Part 7) 310

ITC closing balance of investments from qualified property 320

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day		
1st previous tax year				. . . . . Credit to be applied	901
2nd previous tax year				. . . . . Credit to be applied	902
3rd previous tax year				. . . . . Credit to be applied	903

Total (enter on line A in Part 5)

Part 7 – Calculation of refund for qualifying corporations on investments from qualified property

Current-year ITCs (total of lines 240 and 250 in Part 5) C

Credit balance before refund (amount B from Part 5) . . . . . D

Refund (40 % of amount C or D, whichever is less) . . . . . E

Enter amount E or a lesser amount on line 310 in Part 5 (also enter it on line 780 of the T2 return if the corporation does not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Current expenditures

Current expenditures (from line 557 on Form T661)			
Add:			
Contributions to agricultural organizations for SR&ED*			
Current expenditures (including contributions to agricultural organizations for SR&ED at line 103 in Part 3)* (from line 557 on Form T661)		► 350	
Capital expenditures (from line 558 on Form T661)		360	
Repayments made in the year (from line 560 on Form T661)		370	
Total (this must equal the amount from line 570 on Form T661)*		380	

* Do not file form T661 if you are only claiming contributions made to agricultural organizations for SR&ED.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 only applies if the corporation is a CCPC.

Note: A CCPC that calculates SR&ED expenditure limit, is considered to be associated with another corporation if it meets any of the conditions in subsection 256(1), except where:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation; and
- one of the corporations has at least one shareholder who is not common to both corporations.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . **385** 1 Yes [ ] 2 No [X]

Complete lines 390 and 398, if you answered **no** to the question at line 385 above or if the corporation is not associated with any other corporations (the amounts for associated corporations will be determined on Schedule 49).

Enter your taxable income for the previous tax year* (prior to any loss carry-backs applied). . . . . **390** ____________

Enter your taxable capital employed in Canada for the previous tax year minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. . . . . **398** ____________

* If either of the tax years referred to at line 390 is less than 51 weeks, multiply the taxable income by the following result: 365 divided by the number of days in these tax years.

Part 10 – Calculation of SR&ED expenditure limit for a CCPC

For stand-alone corporations:

Calculation 1A: Tax year ends before January 1, 2010.

[($7,000,000 **minus** (10 x (line 390 from Part 9 or $400,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 1: Tax year starts after December 31, 2009.

[($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)] . . . . ________

Calculation 2: Tax year straddles January 1, 2010.

EE + [(FF **minus** EE) x (GG **divided by** HH)] where, ... ________

EE = [($7,000,000 **minus** (10**A**)) x (($40,000,000 **minus B**) **divided by** $40,000,000)];

FF = [($8,000,000 **minus** (10 x (line 390 from Part 9 or $500,000, whichever is more))) x (($40,000,000 **minus** line 398 from Part 9) **divided by** $40,000,000)];

GG = number of days in the tax year after December 31, 2009;

HH = number of days in the tax year.

Amount A **408** ________ Amount B **409** ________

A = the greater of:

- $400,000; and
- your taxable income for the last tax year* ending in the previous calendar year (tax years ending in 2008) (prior to any loss carry-backs applied).

B = the taxable capital employed in Canada for the last tax year ending in the previous calendar year (tax years ending in 2008) minus $10 million. If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million.

* If any of the tax years referred to in **A** above are less than 51 weeks, gross up the taxable incomes for those tax years by the ratio that 365 is of the number of days in those tax years. Use these grossed up amounts when calculating the expenditure limit.

Enter the amount from Calculation 1A, 1 or 2, whichever is applicable ________ G*

For associated corporations:

If associated, the allocation of the SR&ED expenditure limit as provided on Schedule 49 . . . . **400** ________ H*

Where the tax year of the corporation is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Line G or H ________ x $\frac{\text{Number of days in the tax year}}{365}$ 365 = ... ________ I

Your SR&ED expenditure limit for the year (enter the amount from line G, H, or I, whichever applies) . . . . **410** ________

* Amount G or H cannot be more than $3,000,000.

Part 11 – Calculation of investment tax credits on SR&ED expenditures

Enter whichever is less: current expenditures (line 350 from Part 8) or the expenditure limit (line 410 from Part 10)*	420		x	35 % =		J
Line 350 minus line 410 (if negative, enter "0")	430		x	20 % =		K
Line 410 minus line 350 (if negative, enter "0")			L			
Enter whichever is less: capital expenditures (line 360 from Part 8) or line L above*	440		x	35 % =		M
Line 360 minus line L (if negative, enter "0")	450		x	20 % =		N

Repayments (amount from line 370 in Part 8) . . . .

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit at the rate that would have applied to the repaid amount. Enter the amount of the repayment on the line that corresponds to the appropriate rate.

460		x	35 % =			
480		x	20 % =			
			Total		▶	O

Current-year SR&ED ITC (total of lines J, K, M, N, and O; enter on line 540 in Part 12) . . . .

* For corporations that are not CCPCs, enter "0" on lines J and M.

Part 12 – Calculation of current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
	Subtotal		▶	
ITC at the beginning of the tax year			520	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	530			
Total current-year credit	540			
Credit allocated from a partnership	550			
	Subtotal		▶	
Total credit available				
Deduct:				
Credit deducted from Part I tax (enter on line B2 in Part 30)	560			
Credit carried back to the previous year(s) (from Part 13)			P	
Credit transferred to offset Part VII tax liability	580			
	Subtotal		▶	
Credit balance before refund				Q
Deduct:				
Refund of credit claimed on expenditures of SR&ED (from Part 14 or 15, whichever applies)			610	
ITC closing balance on SR&ED			620	

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	911	
2nd previous tax year				Credit to be applied	912	
3rd previous tax year				Credit to be applied	913	
				Total (enter on line P in Part 12)		

Part 14 – Calculation of refund of ITC for qualifying corporations – SR&ED

Complete this part only if you are a qualifying corporation as determined at line 101.

Is the corporation an excluded corporation as defined under subsection 127.1(2)?	650	1 Yes [ ]	2 No [X]
Credit balance before refund (amount Q from Part 12)		R	
Current-year ITC (lines 540 plus 550 from Part 12 **minus** line O from Part 11)		S	
Refundable credits (amount R or S, whichever is less)*			T
Amount J from Part 11		U	
Subtract: Amount T or U, whichever is less			V
Net amount (if negative, enter "0")			W
Amount W ___ x 40 %			X
Add: Amount V			Y
Refund of ITC (amounts X **plus** Y – enter this, or a lesser amount, on line 610 in Part 12)			Z

Enter the total of lines 310 from Part 5 and 610 from Part 12 on line 780 of the T2 return.

* If you are also an excluded corporation [as defined in subsection 127.1(2)], this amount must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC on line Z.

Part 15 – Calculation of refund of ITC for CCPCs that are not qualifying or excluded corporations – SR&ED

Complete this box only if you are a CCPC that is not a qualifying or excluded corporation as determined in Part 2.

Credit balance before refund (amount Q from Part 12)		AA
Amount J from Part 11	BB	
Subtract: Amount AA or BB, whichever is less		CC
Net amount (if negative, enter "0")		DD
Amount M from Part 11		EE
Amount DD or EE, whichever is less ___ x 40 %		FF
Add : Amount CC above		GG
Refund of ITC (amounts FF **plus** GG)		HH

Enter HH, or a lesser amount, on line 610 in Part 12 and also on line 780 of the T2 return.

RECAPTURE – SR&ED

Part 16 – Calculating the recapture of ITC for corporations and corporate partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, if the credit was earned in a tax year ending after 1997 and did not expire before 2008;
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661;
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures; and
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to.

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

	Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the note above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less
1.			

Subtotal (enter this amount on line LL in Part 17) ______ II

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at line JJ in Part 16.

	A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	**B** Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	**C** Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**
1.			

Calculation 2 (continued) – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil on line JJ below.

	D Amount determined by the formula (A x B) – C	**E** ITC earned by the transferee for the qualified expenditures that were transferred **750**	**F** Amount from column D or E, whichever is less
1.			

Subtotal (enter this amount on line MM in Part 17) ______ JJ

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line KK below.

Corporate partner's share of the excess of SR&ED ITC (amount to be reported on line NN in Part 17) **760** ______ KK

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC for calculation 1 from line II in Part 16		LL
Recaptured ITC for calculation 2 from line JJ in Part 16 above		MM
Recaptured ITC for calculation 3 from line KK in Part 16 above		NN
Total recapture of SR&ED investment tax credit – Add lines LL, MM and NN		OO

Enter amount OO at line A1 in Part 29.

PRE-PRODUCTION MINING

Part 18 – Pre-production mining expenditures

Exploration information

A mineral resource that qualifies for the credit means a mineral deposit from which the principal mineral to be extracted is diamond, a base or precious metal deposit, or a mineral deposit from which the principal mineral to be extracted is an industrial mineral that, when refined, results in a base or precious metal.

In column 800, list all minerals for which pre-production mining expenditures have taken place in the tax year.

	List of minerals 800
1.	

For each of the minerals reported in column 800 above, identify each project, mineral title, and mining division where title is registered. If there is no mineral title, identify the project and mining division only.

	Project name 805	Mineral title 806	Mining division 807
1.			

Pre-production mining expenditures *

Pre-production mining expenditures that the corporation incurred in the tax year for the purpose of determining the existence, location, extent, or quality of a mineral resource in Canada:

Prospecting	810		PP
Geological, geophysical, or geochemical surveys	811		QQ
Drilling by rotary, diamond, percussion, or other methods	812		RR
Trenching, digging test pits, and preliminary sampling	813		SS

Pre-production mining expenditures incurred in the tax year for bringing a new mine in a mineral resource in Canada into production in reasonable commercial quantities and incurred before the new mine comes into production in such quantities:

Clearing, removing overburden, and stripping	820		TT
Sinking a mine shaft, constructing an adit, or other underground entry	821		UU

Other pre-production mining expenditures incurred in the tax year:

	Description 825	Amount 826
1.		

Add amounts at column 826	▶		VV
Total pre-production mining expenditures (add amounts PP to VV)	830		
Deduct: Total of all assistance (grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line 830 above	832		
Excess (line 830 minus line 832) (if negative, enter "0")			WW
Add: Repayments of government and non-government assistance	835		XX
Pre-production mining expenditures (amount WW plus amount XX)			YY

* A pre-production mining expenditure is defined under subsection 127(9).

Part 22 – Calculation of current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				
Deduct:				
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal			▶	
ITC at the beginning of the tax year			625	
Add:				
Credit transferred on amalgamation or wind-up of subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (total of column 605)	640	6,000		
Credit allocated from a partnership	655			
Subtotal		6,000	▶	6,000
Total credit available				6,000
Deduct:				
Credit deducted from Part I tax (enter on line B4 in Part 30)	660	6,000		
Credit carried back to the previous year(s) (from Part 23)			DDD	
Subtotal		6,000	▶	6,000
ITC closing balance from apprenticeship job creation expenditures			690	

Part 23 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	
				Total (enter on line DDD in Part 22)		

CHILD CARE SPACES

Part 24 – Eligible child care spaces expenditures

Enter the eligible expenditures that the corporation incurred to create licensed child care spaces for the children of the employees and, potentially, for other children. The corporation cannot be carrying on a child care services business. The eligible expenditures include:

- the cost of depreciable property (other than specified property); and
- the specified child care start-up expenditures;

acquired or incurred only to create new child care spaces at a licensed child care facility.

Cost of depreciable property from the current tax year

	CCA* class number 665	Description of investment 675	Date available for use 685	Amount of investment 695
1.				

Total cost of depreciable property from the current tax year	715		EEE
Add: Specified child care start-up expenditures from the current tax year	705		FFF
Total gross eligible expenditures for child care spaces (line 715 **plus** line 705)			GGG
Deduct: Total of all assistance (including grants, subsidies, rebates, and forgivable loans) or reimbursements that the corporation has received or is entitled to receive in respect of the amounts referred to at line GGG)	725		HHH
Excess (amount GGG **minus** amount HHH) (if negative, enter "0")			III
Add: Repayments of government and non-government assistance	735		JJJ
Total eligible expenditures for child care spaces (amount III **plus** amount JJJ)	745		

* CCA: capital cost allowance

Part 25 – Calculation of current-year credit – ITC from child care spaces expenditures

The credit is equal to 25% of eligible child care spaces expenditures incurred to a maximum of $10,000 per child care space created in a licensed child care facility.

Eligible expenditures (line 745)			x 25 % =		KKK
Number of child care spaces	755		x $ 10,000 =		LLL
ITC from child care spaces expenditures (amount KKK or LLL, whichever is less)					MMM

Part 26 – Calculation of current-year credit and account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year			
Deduct:			
Credit deemed as a remittance of co-op corporations	765		
Credit expired after 20 tax years	770		
Subtotal			▶
ITC at the beginning of the tax year	775		
Add:			
Credit transferred on amalgamation or wind-up of subsidiary	777		
Total current-year credit (amount MMM above)	780		
Credit allocated from a partnership	782		
Subtotal			▶
Total credit available			
Deduct:			
Credit deducted from Part I tax (enter on line B5 in Part 30)	785		
Credit carried back to the previous year(s) (from Part 27)		NNN	
Subtotal			▶
ITC closing balance from child care spaces expenditures	790		

Part 27 – Request for carryback of credit from child care space expenditures

	Year Month Day			
1st previous tax year	2010-12-31	Credit to be applied	941	
2nd previous tax year	2009-12-31	Credit to be applied	942	
3rd previous tax year	2008-12-31	Credit to be applied	943	
		Total (enter on line NNN in Part 26)		

RECAPTURE – CHILD CARE SPACES

Part 28 – Calculating the recapture of ITC for corporations and corporate partnerships – Child care spaces

The ITC will be recovered against the taxpayer's tax otherwise payable under Part I of the Act if, at any time within 60 months of the day on which the taxpayer acquired the property:

- the new child care space is no longer available; or
- property that was an eligible expenditure for the child care space is:
  - disposed of or leased to a lessee; or
  - converted to another use.

If the property disposed of is a child care space, the amount that can reasonably be considered to have been included in the original ITC (paragraph 127(27.12)(a))	792		ZZZ
In the case of eligible expenditures (paragraph 127(27.12)(b)), the lesser of:			
The amount that can reasonably be considered to have been included in the original ITC	795		
25% of either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value (in any other case) of the property	797		
Amount from line 795 or line 797, whichever is less			OOO

Corporate partnerships

As a member of the partnership, you will report your share of the child care spaces ITC of the partnership after the child care spaces ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 782 in Part 26. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line PPP below.

Corporate partner's share of the excess of ITC	799		PPP
Total recapture of child care spaces investment tax credit – Add lines ZZZ, OOO, and PPP Enter amount QQQ on line A2 in Part 29.			QQQ

Part 29 – Total recapture of investment tax credit

Recaptured SR&ED ITC from line OO in Part 17		A1
Recaptured child care spaces ITC from line QQQ in Part 28 above		A2
Total recapture of investment tax credit – Add lines A1 and A2 Enter amount A3 on line 602 of the T2 return.		A3

Part 30 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (from line 260 in Part 5)		B1
ITC from SR&ED expenditures deducted from Part I tax (from line 560 in Part 12)		B2
ITC from pre-production mining expenditures deducted from Part I tax (from line 885 in Part 19)		B3
ITC from apprenticeship job creation expenditures deducted from Part I tax (from line 660 in Part 22)	6,000	B4
ITC from child care space expenditures deducted from Part I tax (from line 785 in Part 26)		B5
Total ITC deducted from Part I tax (add lines B1, B2, B3, B4, and B5) Enter amount B6 at line 652 of the T2 return.	6,000	B6

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Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
6,000	6,000			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				
2006-12-31				
2005-12-31				
2004-12-31				
2003-12-31				
2002-12-31				
2001-12-31				*
2001-09-30				
2000-09-30				
1999-09-30				
1998-09-30				
1997-09-30				
1996-09-30				
1995-09-30				
1994-09-30				
1993-09-30				
1992-09-30				*
Total				

B+C+D+G **Total ITC utilized** 6,000

* The **ITC end of year** includes the amount of ITC expired from the 10th preceding year if it is before January 1, 1998, or the amount of ITC expired from the 20th preceding year if it is after December 31, 1997. Note that this credit will only expire at the beginning of the subsequent fiscal period. Consequently, this amount will be posted on line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 of the subsequent fiscal year.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

Provide only one number per shareholder

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business Number (If a corporation is not registered, enter "NR") 200	Social insurance number 300	Trust number 350	Percentage common shares 400	Percentage preferred shares 500
1	The Corporation of the City of London	NR			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

On: 2011-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . [ ] Yes [X] No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . [X] Yes [ ] No
   If the answer to question 3 is yes, complete Part "GRIP addition for 2006".

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . [X] Yes [ ] No
5. Corporations that become a CCPC or a DIC . . . . [ ] Yes [X] No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . [ ] Yes [X] No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . [ ] Yes [ ] No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . [ ] Yes [ ] No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . [ ] Yes [X] No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . [ ] Yes [ ] No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . [ ] Yes [ ] No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

GRIP at the end of the previous tax year			100	49,267,462 A
Taxable income for the year (DICs enter "0") *	110	5,469,972 B		
Income for the credit union deduction * (amount E in Part 3 of Schedule 17)	120			
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less *	130			
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income *	140			
Subtotal (**add** lines 120, 130, and 140)		C		
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	5,469,972		
After-tax income (line 150 x general rate factor for the tax year ** 0.7)			190	3,828,980 D
Eligible dividends received in the tax year	200			
Dividends deductible under section 113 received in the tax year	210			
Subtotal (**add** lines 200 and 210)				E
GRIP addition:				
Becoming a CCPC (line PP from Part 4)	220			
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230			
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240			
Subtotal (**add** lines 220, 230, and 240)			290	F
Subtotal (**add** lines A, D, E, and F)				53,096,442 G
Eligible dividends paid in the previous tax year	300			
Excessive eligible dividend designations made in the previous tax year	310			
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.				
Subtotal (line 300 **minus** line 310)				H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)			490	53,096,442
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)			560	
GRIP at the end of the tax year (line 490 **minus** line 560)			590	53,096,442

Enter this amount on line 160 of Schedule 55.

* For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

** The **general rate factor** for a tax year is 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560.

First previous tax year 2010-12-31

Taxable income before specified future tax consequences from the current tax year		7,757,111 J1	
Enter the following amounts before specified future tax consequences from the current tax year:			
Income for the credit union deduction (amount E in Part 3 of Schedule 17)	K1		
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less	L1		
Aggregate investment income (line 440 of the T2 return)	M1		
Subtotal (**add** lines K1, L1, and M1)		N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")		7,757,111	7,757,111 O1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R1

Aggregate investment income (line 440 of the T2 return) . . . . ____ S1

Subtotal (**add** lines Q1, R1, and S1) ____ ▶ ____ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ____ ▶ ____ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") ____ V1

GRIP adjustment for specified future tax consequences to the first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.7) . . . . **500** ____

Second previous tax year 2009-12-31

Taxable income before specified future tax consequences from the current tax year 10,288,016 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ L2

Aggregate investment income (line 440 of the T2 return) . . . . ____ M2

Subtotal (**add** lines K2, L2, and M2) ____ ▶ ____ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 10,288,016 ▶ 10,288,016 O2

Future tax consequences that occur for the current year

Amount carried back from the current year to a prior year

Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	Capital loss carry-back	Restricted farm loss carry-back	Farm loss carry-back	Other	Total carrybacks

Taxable income after specified future tax consequences . . . . ____ P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ____ Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ____ R2

Aggregate investment income (line 440 of the T2 return) . . . . ____ S2

Subtotal (**add** lines Q2, R2, and S2) ____ ▶ ____ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ____ ▶ ____ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") ____ V2

GRIP adjustment for specified future tax consequences to the second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.7) . . . . **520** ____

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year 13,570,105 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Subtotal (**add** lines K3, L3, and M3) ______ ▶ ______ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 13,570,105 ▶ 13,570,105 O3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ R3

Aggregate investment income (line 440 of the T2 return) . . . . ______ S3

Subtotal (**add** lines Q3, R3, and S3) ______ ▶ ______ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") ______ ▶ ______ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") ______ V3

GRIP adjustment for specified future tax consequences to the third previous tax year
(line V3 **multiplied by** the general rate factor for the tax year 0.7) . . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ______ W

Enter amount W on line 560.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or a DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or a DIC in its last tax year)
(line AA **minus** line DD) . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or a DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year . . . . ________ FF

The corporation's money on hand immediately before the end of its previous/last tax year . . . . ________ GG

Unused and unexpired losses at the end of the corporation's previous/last tax year:

Non-capital losses . . . . ________
Net capital losses . . . . ________
Farm losses . . . . ________
Restricted farm losses . . . . ________
Limited partnership losses . . . . ________

Subtotal ________ ► ________ HH

Subtotal (**add** lines FF, GG, and HH) ________ II

All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year . . . . ________ JJ

Paid-up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year . . . . ________ KK

All the corporation's reserves deducted in its previous/last tax year . . . . ________ LL

The corporation's capital dividend account immediately before the end of its previous/last tax year . . . . ________ MM

The corporation's low rate income pool immediately before the end of its previous/last tax year . . . . ________ NN

Subtotal (**add** lines JJ, KK, LL, MM, and NN) ________ ► ________ OO

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or a DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0") . . . . ________ PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 5 – General rate factor for the tax year

Complete this part to calculate the general rate factor for the tax year.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	/ 365	. . . . =		QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	. . . . =		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	365 / 365	. . . . =	0.70000	SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	. . . . =		TT

General rate factor for the tax year (total of lines QQ to TT) . . . . 0.70000 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation*, or Schedule 54, *Low Rate Income Pool (LRIP) Calculation*, whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- All legislative references on this schedule are to the federal *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Do not use this area

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		2,500,000			
Total taxable dividends paid in the tax year	100	2,500,000			
Total eligible dividends paid in the tax year			150		A
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	53,096,442	B
Excessive eligible dividend designation (line 150 **minus** line 160)					C
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			180		D
Subtotal (amount C **minus** amount D)					E
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount E **multiplied** by 20 %)			190		F

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (amount from line A of Schedule 54)					G
Deduct:					
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends*			280		H
Subtotal (amount G **minus** amount H)					I
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount I **multiplied** by 20 %)			290		J

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax. For more information on how to make this election, go to **www.cra.gc.ca/eligibledividends**.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- All legislative references are to the federal *Income Tax Act* and *Income Tax Regulations*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic rate of tax for the year

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	14.00 %	=	%	A1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	12.00 %	=	5.95068 %	A2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	11.50 %	=	5.79726 %	A3

Ontario basic rate of tax for the year (total of rates A1 to A3) 11.74794 ► 11.74794 % A4

Part 2 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . 5,469,972 B

Ontario basic income tax: amount B **multiplied** by Ontario basic rate of tax for the year (rate A4 from Part 1) . . . . 642,609 C

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount C on line 270 of Schedule 5, *Tax Calculation Supplementary – Corporations*. Otherwise, enter it on line 760 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 3 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return)		5,469,972	1
Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return)		5,469,972	2
Federal business limit before the application of subsection 125(5.1) * (amount from line 410 of the T2 return)	______ x ______ =	500,000	3
Enter the least of amounts 1, 2, and 3	line 4 on page 4 of the T2 return	500,000	D

Ontario domestic factor: Ontario taxable income ** / taxable income earned in all provinces and territories *** = 5,469,972.00 / 5,469,972 = 1.00000 E

Amount D x amount E	500,000	a
Ontario taxable income (amount B from Part 2)	5,469,972	b

Ontario small business income (lesser of amount a and amount b) . . . 500,000 F

Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x	8.50 %	=	%	G1
Number of days in the tax year after June 30, 2010, and before July 1, 2011 / Number of days in the tax year	181 / 365	x	7.50 %	=	3.71918 %	G2
Number of days in the tax year after June 30, 2011 / Number of days in the tax year	184 / 365	x	7.00 %	=	3.52877 %	G3

OSBD rate for the year (total of rates G1 to G3) . . . 7.24795 % G4

Ontario small business deduction: amount F **multiplied** by OSBD rate for the year (rate G4) . . . 36,240 H

Enter amount H on line 402 of Schedule 5.

* For 2011 and later tax years, enter the amount from line 410 of the T2 return on line 3 of this schedule. Otherwise, complete the calculation for this line.

** Enter amount B from Part 2.

*** Includes the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 4 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Note: For days in the tax year after June 30, 2010, the small business surtax rate is 0%. You do not have to complete this part if the corporation's tax year begins after June 30, 2010.

Adjusted taxable income * . . . . ______ I

Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501) . . . . ______ J

Aggregate adjusted taxable income (amount I **plus** amount J) . . . . ______ ▶ ______ K

Deduct:

Ontario business limit 500,000

Subtotal (amount K **minus** Ontario business limit) (if negative, enter "0" on this line and on line P) . . . . ______ L

Small business surtax rate for the year:

Number of days in the tax year before July 1, 2010 ______ / Number of days in the tax year 365 x 4.25 % = ______ % M

Amount L **multiplied by** % on line M = ... ______ N

Amount N ______ x Ontario small business income (amount F from Part 3) ______ / 500,000 500,000 = ... ______ O

Surtax re Ontario small business deduction: lesser of amount O and OSBD (amount H from Part 3) . . . . ______ P

Enter amount P on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 5 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Lesser of amount D and amount b from Part 3 . . . . 500,000 Q

Surtax payable (amount P from Part 4) ______ / Ontario domestic factor (amount E from Part 3) x OSBD rate (rate G6 from Part 3) 7.24795 % 0.07248 = ______ R

Note: Enter "0" on line R for tax years beginning after June 30, 2010.

Ontario adjusted small business income (amount Q **minus** amount R) (if negative, enter "0") . . . . 500,000 S

Enter amount S on line U in Part 6 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 6 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D from Part 3 of Schedule 17			T	
Deduct:				
Ontario adjusted small business income (amount S from Part 5)			U	
Subtotal (amount T **minus** amount U) (if negative, enter "0")			V	
OSBD rate for the year (rate G6 from Part 3)	7.24795 %			
Amount V **multiplied** by the OSBD rate for the year				W
Ontario domestic factor (amount E from Part 3)			1.00000	X
Ontario credit union tax reduction (amount W **multiplied** by amount X)				Y

Enter amount Y on line 410 of Schedule 5.

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SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the Ontario *Business Corporations Act* (BCA) or Ontario *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the *Ontario Corporations Information Act*.
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up-to-date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. Visit **www.ServiceOntario.ca** for more information.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
London Hydro Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-04-26	1800266

Part 2 – Head or registered office address (P.O. box not acceptable as stand-alone address)

200 Care of (if applicable)

210 Street number	**220** Street name/Rural route/Lot and Concession number	**230** Suite number
111	Horton Street	

240 Additional address information if applicable (line 220 must be completed first)

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
London	ON	CA	N6A 4H6

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS for the corporation with respect to names, addresses for service, and the date elected/appointed and, if applicable, the date the election/appointment ceased of the directors and five most senior officers, or with respect to the corporation's mailing address or language of preference? To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.

300 1 If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Arnold (Last name) **451** David (First name)

454 ______, (Middle name(s))

460 1 Please enter one of the following numbers in this box for the above-named person: **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number	**530** Street name/Rural route/Lot and Concession number	**540** Suite number

550 Additional address information if applicable (line 530 must be completed first)

560 Municipality (e.g., city, town)	**570** Province/state	**580** Country	**590** Postal/zip code

Part 6 – Language of preference

600 Indicate your language of preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communications with the corporation. It may be different from line 990 on the T2 return.

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SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information	**120** Telephone number including area code
David Arnold	(519) 661-5800

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes [ ] 2 No [X]

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** ____________

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
1.		15.000 %	12,384	30.000 %		18
2.		15.000 %	11,063	30.000 %		11
3.		15.000 %	12,530	30.000 %		18

	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
1.	3,715	3,000	3,000		3,000
2.	3,319	3,000	3,000		3,000
3.	3,759	3,000	3,000		3,000

Ontario co-operative education tax credit (total of amounts in column K) 500 9,000 L

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L ________ x percentage on line 170 in Part 1 ________ % = ... ________ M

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received. Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 552

ONTARIO APPRENTICESHIP TRAINING TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
London Hydro Inc.	86483 7430 RC0001	2011-12-31

- Use this schedule to claim an Ontario apprenticeship training tax credit (ATTC) under section 89 of the *Taxation Act, 2007* (Ontario).
- The ATTC is a refundable tax credit that is equal to a specified percentage (25% to 45%) of the eligible expenditures incurred by a corporation for a qualifying apprenticeship. Before March 27, 2009, the maximum credit for each apprentice is $5,000 per year to a maximum credit of $15,000 over the first 36-month period of the qualifying apprenticeship. After March 26, 2009, the maximum credit for each apprentice is $10,000 per year to a maximum credit of $40,000 over the first 48-month period of the qualifying apprenticeship. The maximum credit amount is prorated for an employment period of an apprentice that straddles March 26, 2009.
- Eligible expenditures are salaries and wages (including taxable benefits) paid to an apprentice in a qualifying apprenticeship or fees paid to an employment agency for the provision of services performed by the apprentice in a qualifying apprenticeship. These expenditures must be:
  - paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario;
  - for services provided by the apprentice during the first 36 months of the apprenticeship program, if incurred before March 27, 2009; and
  - for services provided by the apprentice during the first 48 months of the apprenticeship program, if incurred after March 26, 2009.
- An expenditure is not eligible for an ATTC if:
  - the same expenditure was used, or will be used, to claim a co-operative education tax credit; or
  - it is more than an amount that would be paid to an arm's length apprentice.
- An apprenticeship must meet the following conditions to be a qualifying apprenticeship:
  - the apprenticeship is in a qualifying skilled trade approved by the Ministry of Training, Colleges and Universities (Ontario); and
  - the corporation and the apprentice must be participating in an apprenticeship program in which the training agreement has been registered under the *Ontario College of Trades and Apprenticeship Act, 2009 or* the *Apprenticeship and Certification Act, 1998* or in which the contract of apprenticeship has been registered under the *Trades Qualification and Apprenticeship Act*.
- Make sure you keep a copy of the training agreement or contract of apprenticeship to support your claim. Do not submit the training agreement or contract of apprenticeship with your *T2 Corporation Income Tax Return*.
- File this schedule with your *T2 Corporation Income Tax Return*.

Part 1 – Corporate information (please print)

110 Name of person to contact for more information	**120** Telephone number including area code
David Arnold	(519) 661-5800

Is the claim filed for an ATTC earned through a partnership? * . . . . **150** 1 Yes [ ] 2 No [X]

If **yes** to the question at line 150, what is the name of the partnership? . . . . **160** ______

Enter the percentage of the partnership's ATTC allocated to the corporation . . . . **170** ______ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 552 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 552 to claim the partner's share of the partnership's ATTC. The total of the partners' allocated amounts can never exceed the amount of the partnership's ATTC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . **200** 1 Yes [X] 2 No [ ]
2. Was the corporation exempt from tax under Part III of the *Taxation Act, 2007* (Ontario)? . . . . **210** 1 Yes [ ] 2 No [X]

If you answered **no** to question 1 or **yes** to question 2, then you are **not eligible** for the ATTC.

Part 4 – Calculation of the Ontario apprenticeship training tax credit (continued)

	H1 Number of days employed as an apprentice in the tax year before March 27, 2009 (see note 1 below) 441	H2 Number of days employed as an apprentice in the tax year after March 26, 2009 (see note 1 below) 442	H3 Number of days employed as an apprentice in the tax year (column H1 **plus** column H2) 440	I Maximum credit amount for the tax year (see note 2 below) 445
1.		147	147	4,027
2.		365	365	10,000
3.		365	365	10,000
4.		152	152	4,164

	J1 Eligible expenditures before March 27, 2009 (see note 3 below) 451	J2 Eligible expenditures after March 26, 2009 (see note 3 below) 452	J3 Eligible expenditures for the tax year (column J1 **plus** column J2) 450	K Eligible expenditures **multiplied** by specified percentage (see note 4 below) 460
1.		83,232	83,232	29,131
2.		63,652	63,652	22,278
3.		66,726	66,726	23,354
4.		24,895	24,895	8,713

	L ATTC on eligible expenditures (lesser of columns I and K) 470	M ATTC on repayment of government assistance (see note 5 below) 480	N ATTC for each apprentice (column L or column M, whichever applies) 490
1.	4,027		4,027
2.	10,000		10,000
3.	10,000		10,000
4.	4,164		4,164

Ontario apprenticeship training tax credit (total of amounts in column N) **500** 28,191 **O**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount O:

Amount O ______ x percentage on line 170 in Part 1 ______ % = ... ______ **P**

Enter amount O or P, whichever applies, on line 454 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 552, add the amounts from line O or P, whichever applies, on all the schedules, and enter the total amount on line 454 of Schedule 5.

Note 1: When there are multiple employment periods as an apprentice in the tax year with the corporation, do not include days in which the individual was not employed as an apprentice.
For H1: The days employed as an apprentice must be within 36 months of the registration date provided in column E.
For H2: The days employed as an apprentice must be within 48 months of the registration date provided in column E.

Note 2: Maximum credit = ($5,000 x H1/365*) + ($10,000 x H2/365*)
* 366 days, if the tax year includes February 29

Note 3: Reduce eligible expenditures by all government assistance, as defined under subsection 89(19) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, in respect of the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.
For J1: Eligible expenditures before March 27, 2009, must be for services provided by the apprentice during the first 36 months of the apprenticeship program.
For J2: Eligible expenditures after March 26, 2009, must be for services provided by the apprentice during the first 48 months of the apprenticeship program.

Note 4: Calculate the amount in column K as follows:
Column K = (J1 x line 310) + (J2 x line 312)

Note 5: Include the amount of government assistance repaid in the tax year multiplied by the specified percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the ATTC in that tax year.
Complete a **separate entry** for each repayment of government assistance.

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APPENDIX 4H – PILs 2010 (Assessment MAY 1, 2012)

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Ontario

Ministry of Finance
33 King St W
PO Box 622
Oshawa ON L1H 8H6

HPL - tL060

000004

LONDON HYDRO INC.
ATTENTION: C/O DAVID WILLIAMSON J.STEPHENS
111 HORTON ST E
LONDON ON N6B 3N9

Issue Date	01-May-2012
Business No.	864837430TW0001
Reference No.	L0078396288

Notice of Re-Assessment - Hydro Payment in Lieu

Electricity Act, 1998, Corporations Tax Act

We have received and processed your return for the period ending 31-Dec-2010. Based on the information provided, your return has been corrected as follows:

	Previous	Revised
Total Federal Tax	$1,392,280.00	$1,286,950.00
Total Ontario Tax	$1,167,854.00	$1,137,954.00
Total Credits	($35,014.00)	($35,014.00)
Loss Carry-back	$0.00	$0.00
Total Tax Payable	$2,525,120.00	$2,389,890.00
Interest		$0.00
Current Penalty		$0.00
Credits/Payments		($2,389,890.00)
Total Assessment		**$0.00**

As of 01-May-2012, including the amount assessed above, you have an overall credit balance on your account of ($135,230.00).

If you have any questions concerning this Notice of Re-Assessment, please call the number listed below. After discussion with a ministry representative, if you still do not agree with this re-assessment you have the right to file a Notice of Objection with the Objections and Appeals Branch within 180 days of the issue date of this form. Any taxes, interest and penalties that are outstanding as a result of the re-assessment are due and payable even if you have filed, or intend to file, a Notice of Objection.

If you have any questions or require additional information, please visit our website or call the Ministry of Finance at the number listed below.

Ministry use only

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APPENDIX 4I – PILs 2009 (Assessment JULY 8, 2010)

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Detach and return this REMITTANCE FORM with your payment.

Remittance Advice - Payment-in-Lieu (PIL)

Electricity Act, 1998
Corporations Tax Act, R.S.O. 1990

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Account No.
1800266

35
PX5003

LONDON HYDRO INC.
C/O DAVID WILLIAMSON
111 HORTON ST

LONDON ON
N6A 4H6

10 HPL

Taxation Year End: (YYYYMMDD) [ ]

Payment Amount: $ [ ]

Taxation Year End: (YYYYMMDD) 2 0 0 9 1 2 3 1

Payment Amount: $ [ ]

Total Payment Enclosed: $ [ ]

Keep this portion for your records.

Notice of Assessment

Ontario

Ministry of Revenue
Hydro PIL
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Electricity Act, 1998 ▪ Corporations Tax Act, R.S.O. 1990
from 2009/01/01 **to** 2009/12/31

	Account No.	Assessment Date (year, month, day)	Page
LONDON HYDRO INC.	1800266	2010/07/08	1 of 1

ASSESSMENT NO. 241

Tax: Federal and Provincial PIL		3,789,346.00
Assessment Interest		733.70
Total Assessment Liability		3,790,079.70
SUMMARY OF 2009/12/31 TAXATION YEAR TRANSACTIONS		
Payments/Transfers	5,034,500.00CR	
Sub-Total		5,034,500.00CR
CREDIT BALANCE AVAILABLE IN THIS TAXATION YEAR		1,244,420.30CR

In accordance with s.s.80(8) of the Corporations Tax Act, as made applicable by s.95 of the Electricity Act, 1998, notice is hereby given of the amount of tax, penalty and interest for which you are assessed.

Total tax assessed as per company estimate

Steve Coss, MOF Compliance Electricity
905-837-5201

Walter Johnson
Accounts
905-433-5272

Tax (Re)Assessment Enquiries:	▪ ~~1-866-ONT-TAXS (1-866-668-8297) ext. 21113~~ ▪ FAX 416 218-3276	▪ TTY 1 800 263-7776 ▪ ontario.ca/revenue	Account Billing Enquiries & Change of Address Information:	▪ ~~1-866-ONT-TAXS (1-866-668-8297)~~ ▪ FAX 905 433-5197

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APPENDIX 4J – PILs 2008 (Assessment JULY 27, 2011)

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Ontario

PO Box 622
33 King St. West
Oshawa ON L1H 8H6

CP 622
33 rue King ouest
Oshawa ON L1H 8H6

Ministry of Revenue
Ministère du Revenu

Tax Compliance Branch
Direction de l'observation fiscale

Statement of Adjustments re Taxes Assessed
Relevé des redressements de cotisations

Name of Corporation / Raison sociale de la compagnie	Account No. / N° de compte: 1800266
London Hydro Inc.	Taxation Year End / Fin de l'année d'imposition: 31 December,2008

INCOME TAX

	Federal	Ontario
Taxable Income as previously assessed	$ 13,575,105	$ 13,509,754
Federal Income Tax		
As previously assessed		$ 2,402,532
Ontario Income Tax		
As previously assessed		1,870,767
Federal Part 1.3 Tax		
As previously assessed		0
Revised Ontario Capital Tax		
As per Schedule 1		527,915
TOTAL PAYMENTS IN LIEU OF TAXES		$ 4,801,214

Alan T. Ogle,MRK 665

*"DESIGNATED ASSESSMENT"
The items marked with an asterisk above are designated parts of this assess-ment. This description is authorized by section 92 of the Corporations Tax Act, for assessments which correspond to those issued by Revenue Canada under the Income Tax Act (Canada). It is not necessary to serve a Notice of Objection to those portions of the assessment. The Corporation and the Minister will be bound by the final disposition of a federal Notice of Objection or Appeal.

If you wish not to be bound by the disposition of the corresponding federal objection or appeal, you must serve a Notice of Objection on the prescribed form in accordance with section 84. See under "Notice of Objection" on the accompanying "Notice of Re-Assessment"

*"COTISATION DESIGNEE"
Les postes ci-dessus marqués d'un astérisque sont les parties désignées de cette cotisation. Cette description est autorisée en vertu de l'article 92 de la Loi sur l'imposition des corporations, pour les cotisations qui correspondent à celles établies par Revenu Canada en vertu de la Loi de l'impôt sur le revenu (Canada). Il n'est pas nécessaire de signifier un Avis d'opposition pour ces parties des cotisations. La compagnie et le ministre seront liés par la décision finale relative à l'avis féderal d'opposition ou d'appel.

Si vous désirez ne pas être lié par la décision relative à l'opposition ou à l'appel fédéral correspondant, vous pouvez signifier un avis d'opposition sur la formule prévue à cette fin conformément à l'article 84. Voir "Avis d'opposition" sur l'Avis de nouvelle cotisation ci-joint.

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APPENDIX 4K – LONDON HYDRO PROCUREMENT POLICY

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London Hydro
Purchasing Department Policies and Procedures
Purchase Initiation and Supplier Selection

Procedure No.- Original Release Date: May 28,1997		Revision: - 3 Date: August 23, 2012
Approved By: Director of Finance & Regulatory Affairs	Chief Executive Officer	Chief Financial Officer

1.0 DEFINITIONS

An ***Engineered Product*** is a product requiring a high degree of technical specification, such as primary cable, transformers and other electrical inventory products that require the supplier to demonstrate technical capabilities including performance and/or quality standards prior to being included on an approved vendor list.

A ***Request for Quotation*** is a request for suppliers to submit an unsealed bid for the supply of certain goods or services at a particular price to London Hydro. Characteristics:

- Submitted in an unsealed bid to the Purchasing Department
- Sent directly to the known suppliers of the product or service from an established vendor list
- Not advertised in the public media
- Not opened publicly
- Results are not submitted to the Board of Directors for approval nor awarding of the contract
- Process is used for the acquisition of goods or services greater than $15,000 and less than $25,000.

A ***Formal Request for Quotation*** is a request for suppliers to submit a sealed bid for the supply of certain goods or services at a particular price to London Hydro. Characteristics:

- Submitted in a sealed bid to the Executive Assistant to the Board of Directors, or designate
- Sent directly to the known suppliers of the product or service from an established vendor list
- Not advertised in the public media
- Not opened publicly
- Process is used for the acquisition of goods or services greater than $25,000 and less than $50,000 and for the acquisition of "engineered products" greater than $50,000
- Results are not submitted to the Board of Directors for approval nor awarding of the contract, with the exception of "engineered products" over $50,000 that are not inventory replenishments.

A ***Request for Proposal (RFP)*** is a form of tender document used to purchase complex services where other criteria as well as price will be used to evaluate the bids.
Characteristics:

- Submitted in a formal sealed bid to the Executive Assistant to the Board of Directors, or designate
- Sent directly to the known suppliers of the product or service
- May be advertised in appropriate public media where other potential suppliers may exist
- Not opened publicly unless advertised publicly
- Awarded on the basis of several criteria as well as price
- Results are reported to the Board of Directors after awarding of the contract by appropriate management authorities noted in 8.8
- This process is used for the acquisition of goods or services exceeding $50,000 (excluding engineered products and inventory replenishments).

A ***Tender*** is a request for suppliers to submit a formal sealed bid which contains a written offer made in a specified format for the supply of certain goods or services at a particular price to London Hydro.
Characteristics:

- Submitted in a formal sealed bid to the Executive Assistant to the Board of Directors, or designate
- Sent directly to the known suppliers of the product or service
- Always advertised in appropriate public media
- Always opened publicly
- Awarded on the basis of the lowest price meeting specifications as defined or described in the tender documents
- Results are reported to the Board of Directors after awarding of the contract by appropriate management authorities noted in 8.8
- Process is used for the acquisition of goods or services exceeding $50,000 (excluding engineered products and inventory replenishments).

2.0 PURPOSE

To ensure that the best prices for acceptable products and services are obtained from suppliers in a fair, consistent and unbiased manner which promotes participation from eligible suppliers. To ensure that purchase transactions are properly initiated and assessed in accordance with the authorization levels detailed in the approved signing authority register.

3.0 SCOPE

3.1 These procedures apply to all purchases of services and products initiated by the organization with the exception of the replenishment or acquisition of certain items that fall into the category of "engineered products". (The procedures applied to the acquisition of engineered products are outlined in section 3.1 ii).

In certain circumstances, the selection of suppliers as required by this policy is achieved, in whole or in part, by other acceptable procedures. The following supplier selection procedures are considered to be acceptable and may be utilized in place of the procedures, detailed in this policy:

i) Supplier selection is performed by established organizations or buying groups who ensure adherence to supplier selection criteria similar to and compatible with the principles and policies of this policy. Such organizations can be utilized on the authorization of the Chief Executive Officer (CEO).

ii) Certain products requiring a high degree of technical specification, such as primary cable, transformers and other engineered products, require the supplier to demonstrate technical capabilities and/or performance or quality standards prior to being included on the approved vendor list. All such purchases greater than $15,000 will be subject to either a request for ***quotation*** or formal request for quotation from suppliers on the approved vendor list. In order to classify a product as an engineered product, a Declaration of Engineered Product form must be completed by the requesting department and approved by the Finance Department.

(iii) Maintenance of the approved vendor list will be the responsibility of the Engineering Department.

(iv) The processes detailed in Sections 4.4 and 8.7 will govern the request for and evaluation of quotations.

4.0 RESPONSIBILITIES

4.1 Department Managers will be responsible for adherence to the approved signing authority register in the initiation of purchases for their department.

4.2 Department Managers will be responsible for communication of purchase requests to the Purchasing department for the initiation of supplier selection.

4.3 Overall responsibility for supplier selection in accordance with procedures outlined in sections 5.0 to 8.0 will reside with the Chief Financial Officer (CFO).

4.4 Where there are unique criteria (e.g. technical specifications, performance requirements) which require specialized knowledge, responsibility for the assessment of such criteria will reside with the applicable Department Manager. Upon receipt of the responses to a request for quotation, the Purchasing department will assess and document pricing and standard selection criteria.

The Department Manager shall provide the assessment of the unique criteria and communicate this information to the Purchasing department for consideration in the completion of the supplier selection.

5.0 PURCHASES LESS THAN $15,000

5.1 All purchases less than $15,000 shall be made from a vendor on the approved vendor list.

5.2 If a purchase of less than $15,000 cannot be made from the approved vendor list, supplier selection will be governed by the supplier selection criteria and the reasons for the supplier selection will be documented in the supplier file.

5.3 Vendor evaluation will be made in accordance with the supplier selection criteria prior to the selection of a supplier for inclusion on the approved vendor list.

5.4 The vendor list will be reviewed and updated periodically and each vendor re-examined as to its performance in relation to the supplier selection criteria and the results of this review will be documented in the purchase order file.

6.0 PURCHASES >$15,000 AND <$25,000

6.1 Except as provided in subsequent paragraphs of this section, all purchases will be subject to a request for quotation and require a minimum of three quotes (e-mail and facsimile acceptable). The preparation of the request for quotation and the aggregation of responses will be conducted by the Purchasing department.

6.2 In unique situations where there are reasons to support a lesser number of quotes due to sole source suppliers or other reasons, the circumstances will be documented in the purchase order file accompanied by authorization by the CFO.

6.3 Selection of the supplier will be the responsibility of the CFO and will be directed by the supplier selection criteria.

6.4 The purchase order file shall include documentation of the request for quotation, the responses from all responding suppliers, and the rationale for the selection of any supplier above the lowest quote, accompanied by authorization of the selection by the CFO.

7.0 Purchases >$25,000 AND <$50,000 - Formal Request for Quotation

7.1 Except as noted in 7.5 below, the selection of suppliers will be governed by the same procedures as prescribed in Section 6.0 with the following exceptions and amendments:

7.2 The Executive Assistant to the Board of Directors, or an appropriate designate approved by the CEO, will perform the receipt and aggregation of supplier responses and be responsible for ensuring that the responses are received by the due date and for the accumulation and security of these responses prior to closing date of the formal request for quotation. The responses will not be communicated or conveyed to any person prior to the review by the evaluation team.

7.3 The purchase of ***new*** inventory items that have not been previously inventoried on a regular basis, and where the total initial order is in excess of $25,000, will require the approval of the CEO.

7.4 An evaluation team comprised of the CFO and two other individuals in positions not related to the Purchasing department will perform the evaluation and selection of the supplier. The evaluations will be conducted at established intervals as determined by the Purchasing department.

7.5 For all non-recurring expenditures related to consulting, professional services and similar expenditures for which there is the potential for high public exposure regarding the selection of the supplier, the nature of the review and its results, or the potential for incremental fees beyond the initial scope of the project, the supplier selection will be governed by the Tender or Request for Proposal process as detailed in Section 8.0. The responsibility for the identification of qualifying purchases will reside with the Department Manager initiating the request.

8.0 PURCHASES > $50,000

(a) <u>Process and Submission Evaluation</u>

For the acquisition of "Engineered Products" and the replenishment of inventory, the Formal Quotation process will be used. For all other goods and services, the Tender or Request for Proposal procedure will be used.

8.1 Purchases greater than $50,000 will be subject to the Formal Quotation, Tender or Request for Proposal process. The responsibility for the identification of qualifying purchases will be the responsibility of the Department Manager.

8.2 The Department Manager will be responsible for the organization of the evaluation team, which will include members with the appropriate knowledge base to create the Formal Quotation, Tender or Request for Proposal and evaluate the responses received. The evaluation team will consist of an appropriate number of members to conduct the evaluation process and will include members from areas other than the department initiating the request.

8.3 No publicly advertised Tender or Request for Proposal will be released without the prior written authorization of the CEO or designate.

8.4 The Purchasing department will be responsible for the co-ordination, control and documentation of the requests distributed.

8.5 The Executive Assistant to the Board of Directors, or an appropriate designate approved by the CEO, will perform the receipt and aggregation of supplier responses and be responsible for ensuring that the responses are received by the due date and for the accumulation and security of these responses prior to the public opening. The public opening procedure is applicable for the Tender and Request for Proposal processes only.

8.6 A public opening of the responses received will occur as stated in the Tender or Request for Proposal documents immediately after the closing time in the presence of the Executive Assistant to the Board of Directors (or designate), the CEO or designate and the CFO or designate. The CEO or designate will sign each response and a log maintained of all qualifying responses completed and retained in the Executive offices.

8.7 The evaluation team will be responsible for the evaluation of the responses received in accordance with the criteria established and documented in the Formal Quotation, Tender or Request for Proposal document. The team will be further responsible for the summarization and communication of the results including the provision of all information to the Purchasing department. The Purchasing department will be responsible for the retention of all information relating to the process.

(b) <u>Approval and Award of Purchases > $50,000</u>

8.8 Exception: The guidelines listed in this section pertain to approval awards for specific projects, direct item purchases and single-year contracts. Any approval awards committing to multi-year contracts will be presented to the Board of Directors for approval.

8.9 The evaluation and other information and results will be summarized in the standard format and submitted with sufficient information to allow those in the approval process to make an assessment. The summary will be signed by the VP of the business unit requesting the purchase/award.

8.10 In addition to the department supervisor and the Purchasing Coordinator, the following signatures are required to be obtained for each department requesting approval:

- 8.10.1 For Engineering and Operations: the Chief Engineer & Vice President (VP) of Operations; the CFO; and the CEO;
- 8.10.2 For Corporate Services: the VP of Corporate Services; the CFO; and the CEO;
- 8.10.3 For the Finance Department: a VP other than the CFO; the CFO; and the CEO;
- 8.10.4 For Executive Services: a VP other than the CFO; the CFO; and the CEO.

The above noted approvals of contracts, including formal quotes for the replenishment of inventory, are reported to the Board of Directors on the monthly expenditure reports of amounts over $5,000.